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UKERC Review of Evidence for Global Oil Depletion

Technical Report 4:

Decline rates and depletion rates

July 2009: REF UKERC/WP/TPA/2009/019

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Preface

This report has been produced by the UK Energy Research Centre's Technology and Policy Assessment (TPA) function.

The TPA was set up to address key controversies in the energy field through comprehensive assessments of the current state of knowledge. It aims to provide authoritative reports that set high standards for rigour and transparency, while explaining results in a way that is useful to policymakers.

This report forms part of the TPA's assessment of evidence for **near-term physical constraints on global oil supply**. The subject of this assessment was chosen after consultation with energy sector stakeholders and upon the recommendation of the TPA Advisory Group, which is comprised of independent experts from government, academia and the private sector. The assessment addresses the following question:

What evidence is there to support the proposition that the global supply of 'conventional oil' will be constrained by physical depletion before 2030?

The results of the project are summarised in a *Main Report*, supported by the following *Technical Reports*:

1. Data sources and issues
2. Definition and interpretation of reserve estimates
3. Nature and importance of reserve growth
4. Decline rates and depletion rates
5. Methods for estimating ultimately recoverable resources
6. Methods for forecasting future oil supply
7. Comparison of global supply forecasts

The assessment was led by the Sussex Energy Group (SEG) at the University of Sussex, with contributions from the Centre for Energy Policy and Technology at Imperial College, the Energy and Resources Group at the University of California (Berkeley) and a number of independent consultants. The assessment was overseen by a panel of experts and is very wide ranging, reviewing more than 500 studies and reports from around the world.

Technical Report 4: Decline rates and depletion rates examines how rapidly the production from different categories of field is declining and how this may be expected to change in the future. It also assesses how rapidly the remaining resources in a field or region can be produced. The topics covered include definitions and models of decline and depletion rates, illustrative examples and current estimates of regional and global average rates.

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1 Introduction

The dispute between 'optimists' and 'pessimists' over the future of global oil supply is underpinned by equally polarised disagreements over a set of more technical issues. Given the complexity and multi-dimensional nature of this topic, the existence of such disagreements is unsurprising. However, the situation is made worse by the inadequacy of the publicly available data and the scope this creates for competing views and interpretations. Improved data on individual fields could go a long way towards resolving such disagreements, but this seems unlikely to become available in the foreseeable future. Nevertheless, there is potential for increasing the degree of consensus in a number of areas and some progress has already been made. This report looks in more detail at two of these issues, namely:

- *Decline rates*: how rapidly the production from different categories of field is declining and how this may be expected to change in the future.
- *Depletion rates:* how rapidly the remaining resources in a field or region can be produced.

Section 2 summarises the causes of production decline and introduces some simple empirical equations to model decline. Section 3 provides some illustrative examples of production decline at both the field and regional level and shows how decline rates can vary with the size and age of fields. Section 4 summarises the results of three studies that seek to estimate the global average rate of decline of post-peak oil fields and to forecast how this may change in the future. This variable is of critical importance for future global oil supply. Section 5 examines the related concept of depletion rates, including the available estimates of the rate of depletion the different types of field and the importance of this variable for global supply forecasts. Section 6 concludes.

2 Analysis of decline rates

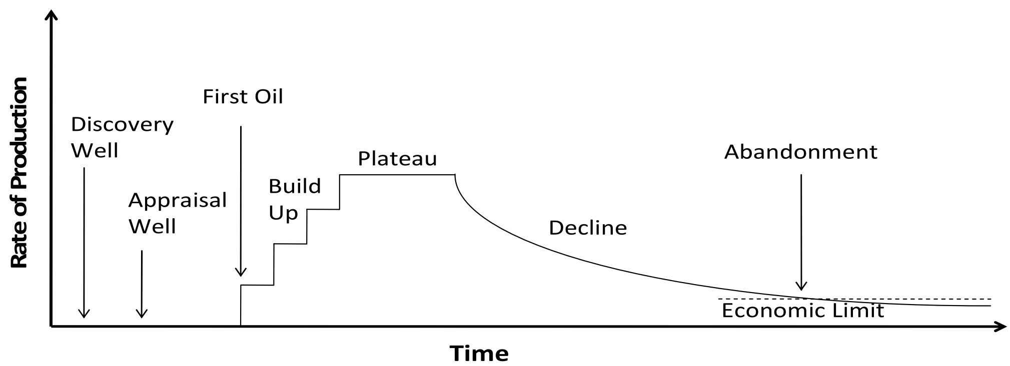
While most analysts focus upon global demand trends, a more important determinant of future investment needs is the rate of decline of production from currently producing fields. Supply forecasts are more sensitive to assumptions about the rate of decline than to assumptions about future oil demand, but the former have generated controversy owing to lack of data (Simmons, 2000). This section examines the source and nature of production decline shows how it can be analysed.

1.1 The nature of production decline

Oil field decline is the gradual fall in the *rate* of production that is observed in oil-fields that are past their peak of production.

The production profile of individual fields can vary widely depending upon their geology and location and the manner in which they are developed (Figure 2.1). As a field is brought on-line, its rate of production typically rises rapidly to a peak which may extend into a multi-year plateau as a consequence of the limited capacity of the surface facilities and/or the steady development of the field through additional drilling. The length of plateau tends to be greater for large fields and the production profile can be complicated by interruptions and the introduction of new technology. But at some point, the rate of production will begin to decline. The decline phase usually encompasses the bulk of the field's producing life, with more than half of the recoverable resources of a field being produced during the decline phase.

Figure 2.1 Stylised production profile of an oil field



Source: Höök (2009)

Decline arises for several physical reasons, but primarily from the fall in reservoir pressure, and consequently the rate at which oil flows from the reservoir rock into the well. Other causes can include the movement of fine mineral grains in the fluid that progressively block pore throats, or the formation of tiny bubbles of gas as pressure falls. Ultimately, water break-through occurs, when the formation water that underlies the oil reaches the well bore, and thereby severely displaces the production of oil. In mature fields, the ‘water-cut’ may represent 90% or more of the volume of produced liquids.

The term ‘decline’ is loosely applied at various levels of aggregation, including single wells, reservoirs, fields, basins and countries. When applied to a region, it is important to distinguish between the *overall* decline rate which includes fields that have yet to pass their peak, and the *post-peak* decline rate which refers to the subset of fields that are in decline (see Box 2.1). Regional decline rates may either be quoted as a simple average of the decline rates of individual fields or, more usefully, as the production-weighted average.

Decline rates are normally measured on an annual basis, but since the production profile of individual fields is rarely smooth, the point at which decline begins can be ambiguous. The plateau period is commonly defined in terms of an annual rate of production that is greater than 95% of that in the peak year, but the precise figure can vary from one study to another. The onset of decline is commonly defined as the end of the plateau period, but in some cases decline may be defined as beginning immediately after the year of peak production.

Box 2.1 Decline rate definitions

Build-Up Phase is the period of production from a field before peak production is reached.

Peak Production is the highest annual production recorded at a field or region.

Plateau is defined as the period during which the annual production of a field exceeds some percentage of the peak production from that field.

Decline is defined the period during which the annual production from a field is falling. The onset of decline is normally defined as when annual production falls some percentage below peak production. Normally this coincides with the end of the plateau period, but in some cases decline may be defined as beginning immediately after the year of peak production.

Post Peak Decline Rate is the annual decline rate of a single field once decline has begun. The decline rate is commonly averaged over several years. If decline is defined as beginning immediately after the year of peak production, a distinction may be made between the post-peak decline rate and the post-plateau decline rate. But if decline is defined as beginning at the end of the plateau period, these measures are the same.

Aggregate Post Peak Decline Rate is the average annual rate of production decline from a group of fields that are past their peak of production. This may either be a simple average or (more commonly) a production-weighted average.

Overall Decline Rate is the average decline rate for a group of fields where some are in build-up, some are in plateau and some are in decline. This is normally a production-weighted average.

Observed Decline Rate is the decline rate which can be measured from available production data. This may refer to the post-peak decline rate of a single field, all the aggregate post-peak or overall decline rate of a group of fields. This measure of decline includes the effects of capital investment for secondary or enhanced recovery.

Natural Decline Rate is the estimate of the decline rate that would have occurred in the absence of extra capital investment. For individual fields or groups of fields where no capital investment is applied, the observed decline rate is equal to the natural decline rate.

There are three categories of oil **Recovery:**

Primary Recovery is the recovery of oil under its own pressure, involving no capital investment beyond that associated with the initial development of the field

Secondary Recovery is the recovery of oil using techniques such as water flooding or gas injection which requires additional capital investment.

Enhanced Oil Recovery (EOR) is the recovery of oil using techniques which change the properties of oil. This typically involves the introduction of gas, solvents, chemicals, microbes, directional boreholes or heat.

1.2 Empirical equations to model production decline

Production from individual wells, reservoirs and fields is usually assumed to decline exponentially at a constant rate, although there is no physical law requiring this and the rate of decline often falls during the later stages of the production cycle. Arps (1945) introduced empirical equations to model production decline that have since seen wide application.[1] While production from some fields may only be poorly approximated by such curves, they often work well for groups of fields.

[1] See for example Chaudhry (2003), Porges (2006) and Guo, *et al.* (2007).

The Arps (1945) decline curves are defined by three variables: the initial rate of production ($Q'(t_0)$), the curvature of decline (β) and the rate of decline (λ). The general *hyperbolic* equation for the rate of production is:

$$Q'(t) = \frac{Q'(t_o)}{(1+\lambda\beta(t-t_0))^{1/\beta}}$$

If $\beta = 0$, this reduces to *exponential* decline:

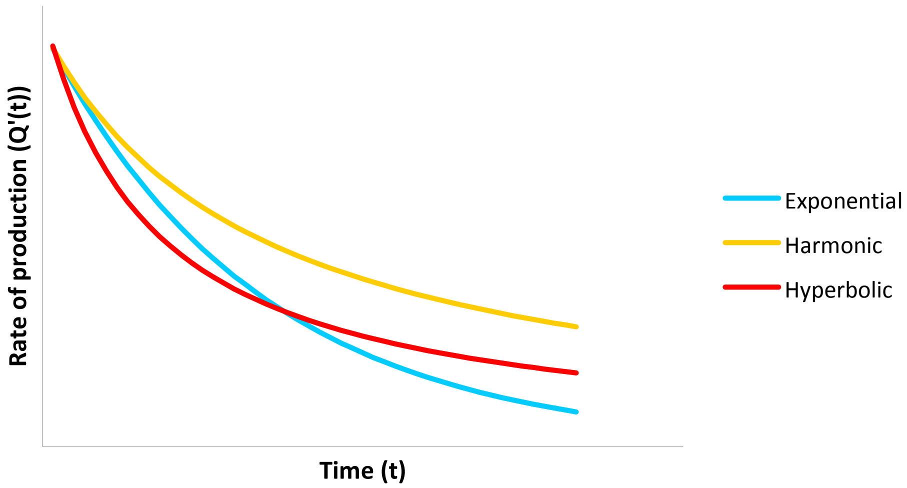
$$Q'(t) = Q'(t_o)e^{-\lambda(t-t_0)}$$

If $\beta = 1$, this reduces to *harmonic* decline:

$$Q'(t) = \frac{Q'(t_0)}{(1+\lambda(t-t_0))}$$

These three cases are presented in Figure 2.2.

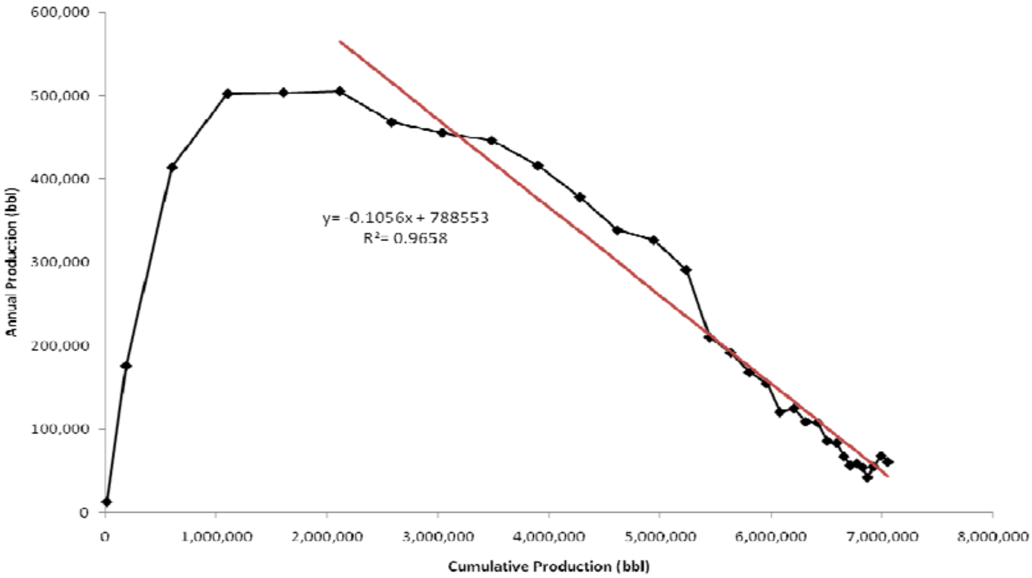
Figure 2.2: Exponential, harmonic and hyperbolic cases of the Arps Equation



It is difficult to predict which of these curves will provide the best fit when applied to the data of a given field (Agbigbi and Ng, 1987). The exponential model is the most widely used, largely on the grounds of simplicity, but it can underestimate production during the later stages of a field's life. In contrast, the harmonic decline curve can do the opposite.

If decline is approximately exponential, a plot of the rate of production as a function of cumulative production is approximately linear (Figure 2.3). This means that the ultimately recoverable resources (URR) of a the field may be estimated by plotting production against cumulative production, fitting a linear regression and extrapolating this until it crosses the cumulative production axis. This technique is widely used, but alternative functional forms for decline rates should also be investigated since the exponential model can underestimate the URR (Kemp and Kasim, 2005; Li and Horne, 2007).

Figure 2.3 Linearisation of exponential production decline for the UK Forties field



Source: Gowdy and Roxana (2007)
Note: The introduction of EOR techniques in 1986 appears to have only temporarily increased production in this field without having a significant impact on the URR. Gowdy and Roxana (2007) observe similar patterns in the Yates field in Texas and at Prudhoe Bay in Alaska, where EOR appears to have increased production at the expense of steeper decline rates in later years. Whether this conclusion applies more generally is a topic of considerable dispute.

Decline models have since been developed in a variety of ways, including linearised curves (Li, 2003; Luther, 1985; Spivey, 1986), and the econometric analysis of residuals (Chen, 1991). Kemp and Kasim (2005) proposed an alternative logistic model of oil field decline:

$$D(t) = \frac{D(\infty)}{1 + be^{-at}}$$

Where *D(t)* is the current relative-to-peak production decline rate and $D(\infty)$ is the asymptotic or steady state decline rate. Kemp and Kasim (2005) found that this provided a better fit than the Arps curves when applied to data for fields in the UK Continental Shelf (UKCS).

In practice, no single decline equation fits every case. In what follows, we will apply the simple exponential decline model, noting that case histories may deviate above or below this model, and that the model is always only an approximation to real-life behaviour.

1.3 Affecting decline rates

Decline is almost irreversible. During typical secondary recovery, more wells are drilled, and pressure is raised by the injection of water or gas (air, nitrogen). These can temporarily reduce the decline rate but do not generally raise the total recovery. These techniques rarely access oil that was otherwise physically unobtainable and may presage a higher subsequent decline rate (Gowdy and Roxana, 2007). Enhanced oil recovery techniques, (EOR), such as the injection of steam or solvents (light hydrocarbons, carbon dioxide), can slow decline, and also raise the eventual total recovery. The cost of EOR is high (especially for smaller fields), making economics a major control on decline rates through the amount of investment deemed cost-effective.

It is common to differentiate between *natural* field decline, where no interruption or further engineering activity occurs; *managed* field decline, where interruptions (e.g. break-downs) occur and efforts to enhance recovery are made; and *manipulated* decline, where rates of production levels are restricted by management policy (e.g. OPEC quotas). The rate of decline can differ according to this context. It is important to be precise in defining exactly *what* is declining, and under what conditions. The most useful general value is probably the *overall regional decline rate*, because this provides the most accurate picture of what happens in the real world of reservoir management and unexpected interruptions, averaged over a group of producing fields in the region.

The economics of modern oil production typically dictates that fields should be produced rapidly, so that cash and resources are tied up for the shortest time. Off-shore fields have higher costs associated with their rigs, platforms and infrastructure, and tend to be produced at higher rates than many on-shore fields, to recover these costs sooner. Consequently off-shore fields may be expected to have higher peaks, shorter plateaus, and steeper declines.

1.4 Data sources for estimating decline rates

The analysis of decline rates requires time-series data of the rates of production from individual fields. A reliable record of annual production is required and decline must be well established for some years. Also, to obtain a good estimate of the managed or natural decline rate, production should not be restricted for economic or political reasons.

Unfortunately, there is relatively little data of this type available in the public domain. Indeed, for most giant and supergiant fields[2], there is virtually no publicly available data, and the analyses of smaller fields presented here should be used cautiously since other fields will have different decline characteristics. There are several commercial database providers, such as IHS and Wood Mackenzie, but these are beyond the financial reach of most analysts. Some useful public data sources include the following:

- The final issue of the *Oil and Gas Journal* each year contains annual production data for hundreds or thousands of individual fields, although there has been a trend in recent years for data to be consolidated by country or production company
- Data for Australian field is available from the APPEA web-site, as well as the West Australian Oil and Gas Review.

[2] We follow the IEA (2008) in defining super-giant fields as having a URR exceeding 5 Gb, 'giant' fields as having a URR in the range 0.5-5 Gb and 'large' fields as having a URR in the range 0.1-0.5 Gb.

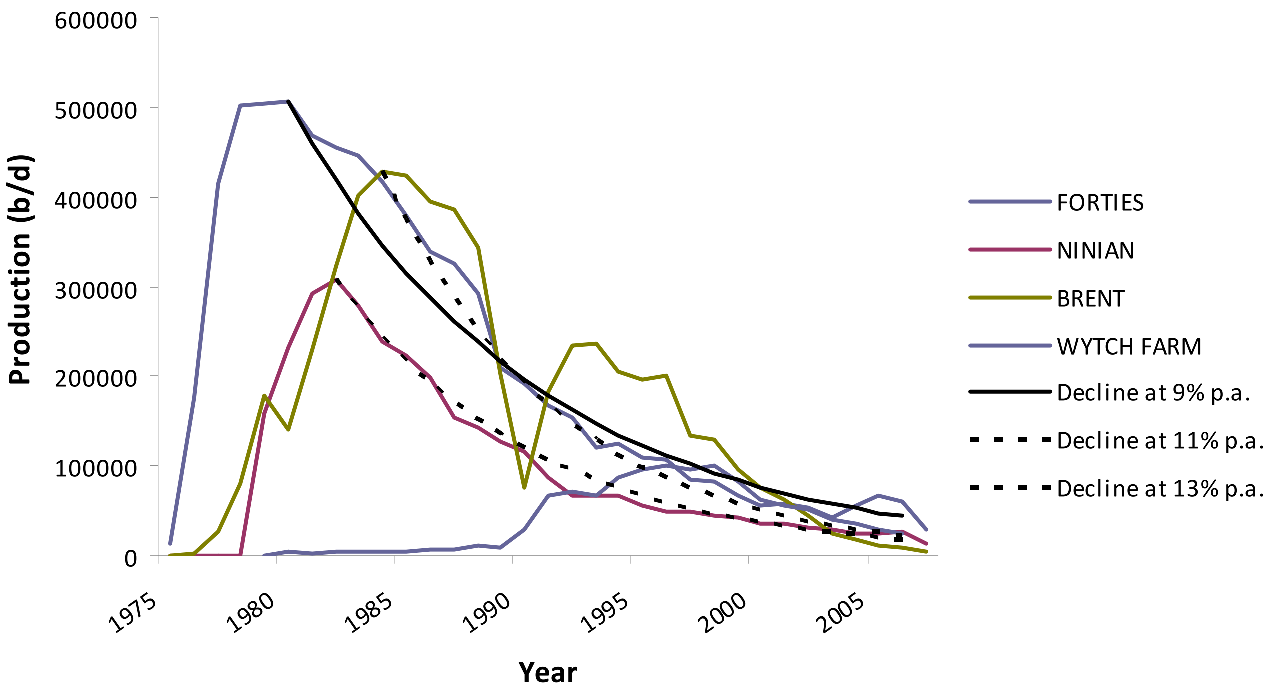
- For UKCS fields, BERR has an excellent database.
- For Gulf of Mexico fields, the Minerals Management Service provides data but this is often scattered or catalogued by block rather than by field.
- Past issues of the IEA's *World Energy Outlook* contain some useful field production and reserves data for major producing countries.
- The EIA provides some data on international fields, but this is scattered throughout its international summaries.
- Data on individual fields throughout the world can frequently be obtained from news reports and company press or data releases.

3 Examples of Decline

1.5 Examples of single field decline

Figure 3.1 shows the annual production from start-up of the UK's three largest North Sea (i.e. off-shore) fields by peak production rate – Forties, Brent and Ninian – and Wytch Farm, the UK's largest onshore field. This is entirely a managed decline, with various efforts made to increase productivity and ultimate recovery. No account is taken of disruptions, e.g. for break-downs or maintenance – these affect all fields, and this is therefore an estimate of actual field behaviour under realistic conditions.

Figure 3.1: Production from four UK oil fields fitted by three exponential decline models



Source: BERR

By the end of 2006:

- Forties had produced 2,575 mb, of which 30% was produced up to and including the peak year, production had declined to 60,700 b/d, and peak production in 1979 was 505,300 b/d. Plateau production had lasted for three years.

- Brent had produced 2,006 mb, of which 33% was produced up to and including the peak year, production had declined to 8,700 b/d, and peak production in 1984 was 428,000 b/d. Plateau production had lasted for two years.

- Ninian had produced 1,171 mb, of which 31% was produced up to and including the peak year, production had declined to 26,500 b/d, and peak production in 1982 was 307,400 b/d. Plateau production had lasted for up to two years.

- Wytch Farm, the on-shore field, had produced 419 mb, of which 50% was produced up to and including the peak year, production had declined to 24,200 b/d, and peak production in 1996 was 100,500 b/d. The end of plateau was in 1998 at 99,800 b/d. Plateau production had lasted for four years.

Overall from peak, Forties appears to show around 9% per year exponential decline, Ninian a good fit at 11% per year, and Brent a very poor fit of around 12% per year. Initial decline rates for Forties and Brent were much lower, and later rates correspondingly higher; Brent has declined at an average 23%/year since 1993. Wytch Farm's eventual decline rate is similar to the off-shore fields, but much more oil was produced pre-peak.

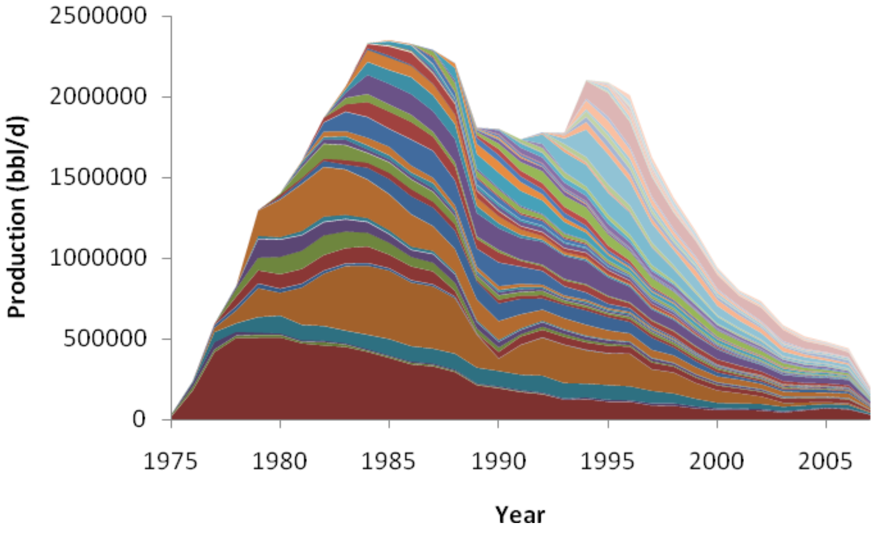
1.6 Examples of regional decline

Figure 3.2 below shows the annual production for a group of 77 North Sea UKCS fields, which is the subset which reached peak in or before 1996, excluding Piper.[3] Each field therefore has a minimum ten-year history of decline. These data are confined to oil, and neither adjusted for increases due to secondary recovery or EOR, nor for decreases due to disruptions. Note that production from the UKCS underwent a hiatus following the Piper Alpha explosion in 1988, when new developments were delayed.

Figure 3.3 shows the same curves stacked around their peak year. The post-Piper "saddle" is still apparent, but a steady decline is also evident. Figure 3.4 shows the same data normalised to 100% at peak. This suggests that the production-weighted average decline rate of this group of post-peak fields is approximately 12.5%/year. Production up to and including the peak year was 5,496 mb, and in the following ten years was 8,463 mb. At least 60% of production has been post-peak, and these fields are still producing.

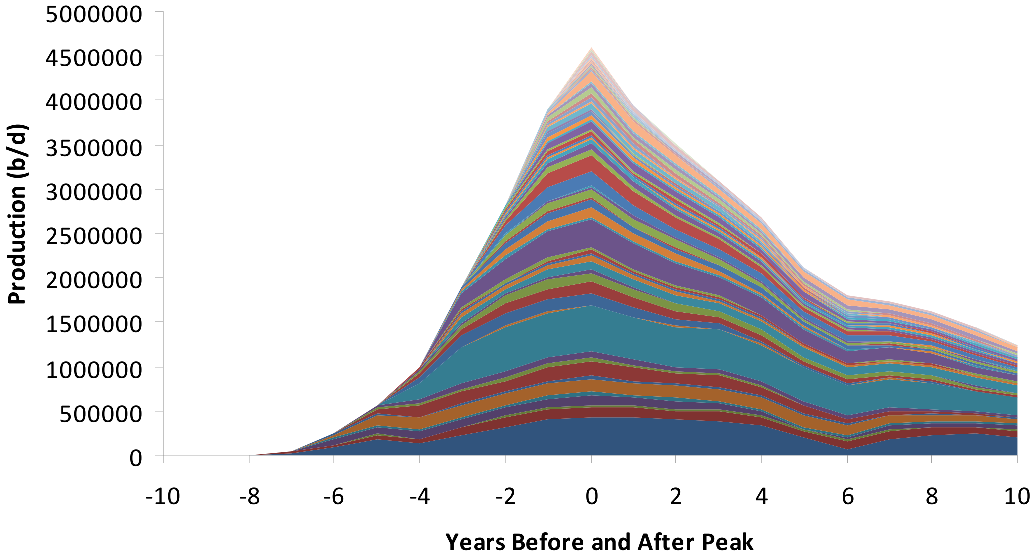
[3] Piper Alpha production was interrupted for some years by a disastrous explosion in 1988. The entire UKCS industry was required to carry out a significant programme of safety inspection and upgrading which interrupted normal exploration and development, and sometimes production.

Figure 3.2: Oil production from UKCS fields which peaked before 1997



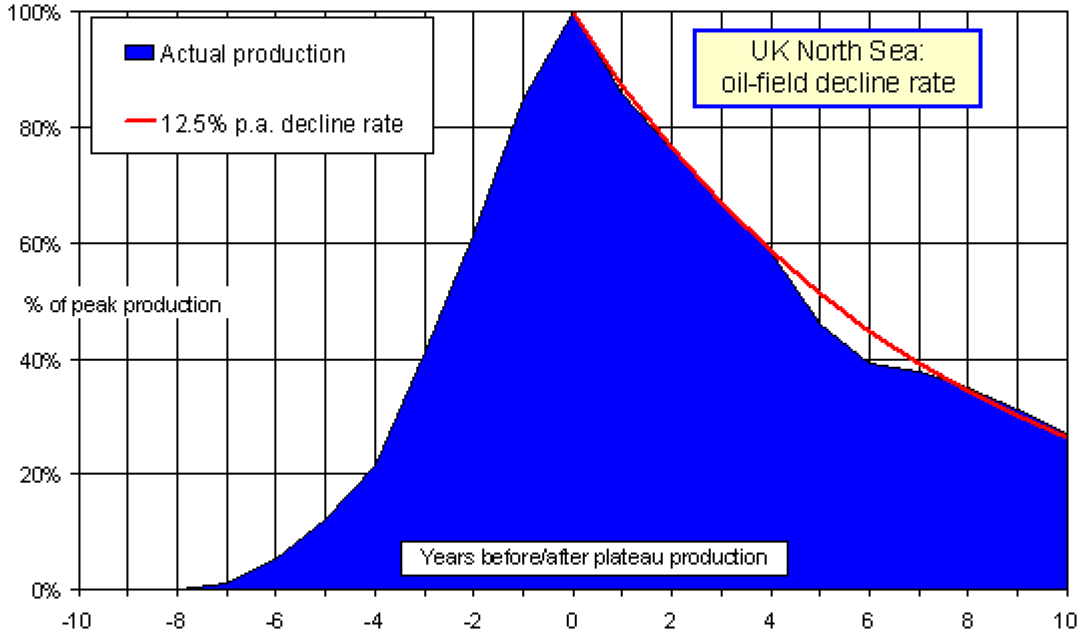
Source: BERR

Figure 3.3: Oil production from UKCS fields which peaked before 1997, stacked by peak year



Source: BERR

Figure 3.4: Estimated production-weighted average decline rate of UKCS oil fields which peaked before 1997



Source: BERR

Similar analyses have been carried out for several other regions, as illustrated in Figure 3.5. The following observations may be made on this Figure:

- *Argentina onshore (7%/year)*: This database is old and occasionally incomplete. The data are stacked by peak as far as this is known. This chart does not show the growth which preceded the peak, because for a few old fields there may be an earlier, unknown peak.

- *Alberta offshore (4.6%/year):* This shows a clear picture of managed basin decline. Secondary recovery and EOR have been practiced, and the effect can be clearly seen in the raw data.[4] The fields in this chart are not stacked by peak but by year, the available data set being incomplete for earlier years, but the chart suffices to show the decline.

- *Australia offshore (15%/year):* Relatively good data is available for this region.

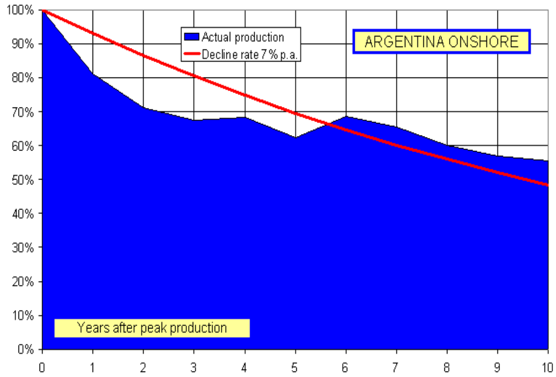
- *Norway offshore (10%/year)*: The data for Norway is readily available from the Norwegian Petroleum Directorate. In a recent analysis of this data Höök and Aleklett (2008) found an average production-weighted decline rate of 13.8%/year for the giant fields and 18.%/year for the 'dwarf' fields (i.e. higher than indicated here).

[4] The data source used for Alberta fields, *Oil and Gas Journal*, contains serious errors. In the 1992 data set there is complete mis-matching of individual fields and production rates, although the total appears correct. In the 1997 data set, the second half of the volume data was obviously shifted down one place in the table. In the 2000 data set, one field datum has an extra digit. In the 2004 data, most of the volume data was shifted down one place in the table.

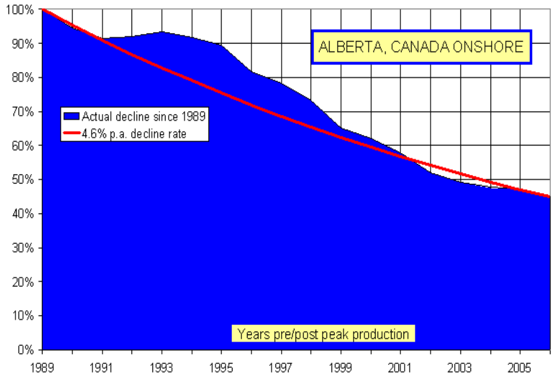
- *Brazil offshore (5-12%/year)*: A two-stage decline appears to be a better fit than a single stage of this region.

- *Gulf of Mexico offshore (20-23%/year)*: Two possible decline curves might fit the available data.

Figure 3.5: Average post-peak decline rates for various countries. Other than Canada and Argentina, all fields are stacked by peak year (see notes below)



Source: OGJ



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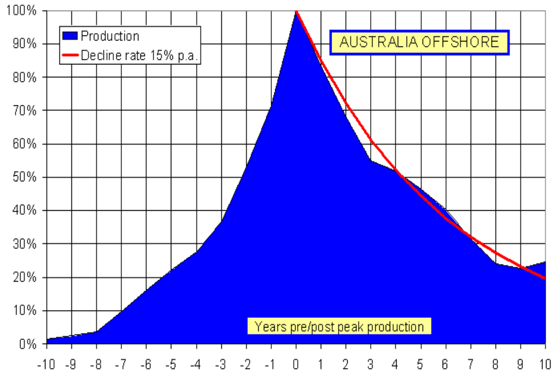
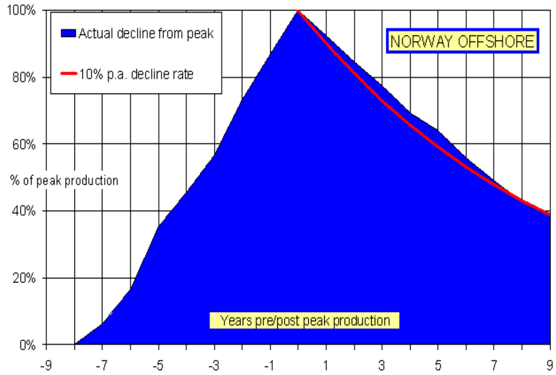


Source: APPAE



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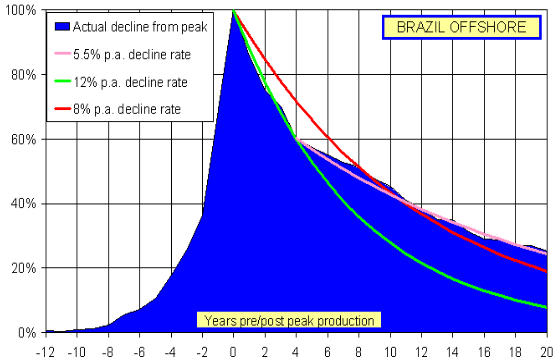

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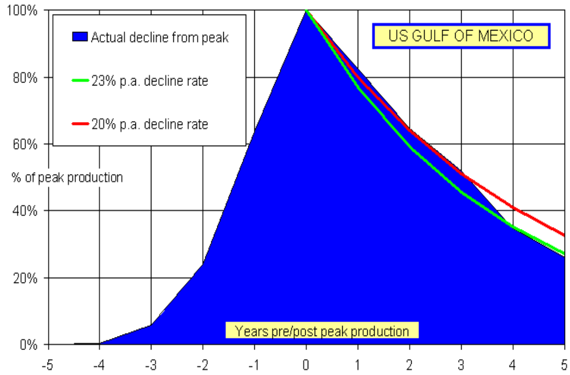


Source: MMS

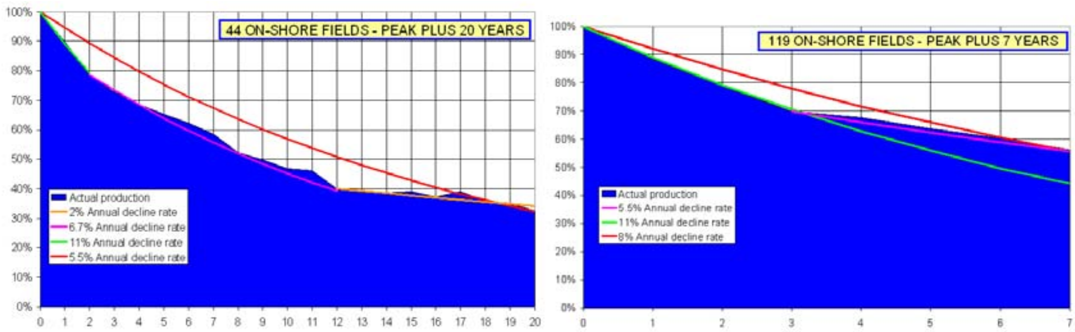
1.7 On-shore and off-shore basins

Figure 3.5 suggests that offshore fields decline faster than onshore fields. Australia, UK offshore, Norway, Gulf of Mexico and Brazil are good examples of offshore developments, at a variety of water depths, and show decline rates up to 23%/year.

Only two onshore regions, Alberta and Argentina, have comprehensive data sets. Figure 3.6 compiles data from 119 onshore oil fields of significant size from 14 countries. There are no Russian, Chinese or American fields, and only one Middle Eastern field. All have at least 7 years of decline. The data are not adjusted for secondary recovery or EOR effects, nor for decreases due to disruptions, but fields with obvious multiple peaks due to EOR, and those liable to OPEC quotas, are excluded. As far as possible, the charts of Figure 3.6 commence at the peak, but again poor data may mean that a few fields had an earlier peak. Charts are shown for 7 and 20 years after peak; the data set for 20 years consists of just 44 fields.

The most rapid decline measured onshore is around 11%/year, and the average is 5-8%. Partial data available but not shown suggests that the largest onshore fields have decline rates of the order of just 2-4%. Moreover, the decline rate clearly decreases with time.

Figure 3.6: Onshore field decline, for 20 years, (left) and 7 years (right) after peak production. The red curve in each chart is a single, fixed, approximate decline curve, but the actual decline rate falls with time



Source: OGJ, MMS,

1.8 Changes in decline rates with time

The common view is that field annual decline rates drop with time, so that production rates eventually become more stable. To the extent that this is the case, the simple exponential decline may not be the best long-term model. However, evidence is mixed on this point.

Off-shore, a single decline rate ranging from 10 to 20%/year is a reasonable fit to each of the basins in Figure 3.5, except Brazil. Here, the decline rate is around 12%/year for the first four years, but then falls sharply to 5.5%/year for the next 16 years. For the on-shore basins in Figure 3.5, a progressive drop in the decline rate is apparent. Decline is initially around 11%/year for the first two years, then falls to 6.7%/year until year 12, then falls again to around 2% until year 20.

The falling decline rate may be a real physical effect, or may be related to the fact that the fields which have been in decline for 20 years are relatively old. Since they were developed much earlier than fields which have only been in decline for 7 years, it is possible that they were developed in a different manner.

1.9 Changes in field decline rate with age

Figure 3.7 shows the average decline rate for suites of UKCS fields that entered decline at 5-year intervals. Table 3.1 presents the average field size within each of these intervals. The earliest suite, of just 6 fields which passed peak between 1976 and 1980, declines at about 8%/year, but exponential decline is not a good fit. The 1981-1985 and 1986-1990 tranches show increasing rates of exponential decline at 11.5%/year and 13%/year respectively. The last three tranches, of fields which passed peak between 1991 and 2005, are essentially similar, showing an early exponential decline of some 20% which appears to reduce significantly after 4 years.

Figure 3.7: Decline curves for UKCS fields entering decline at 5-year intervals

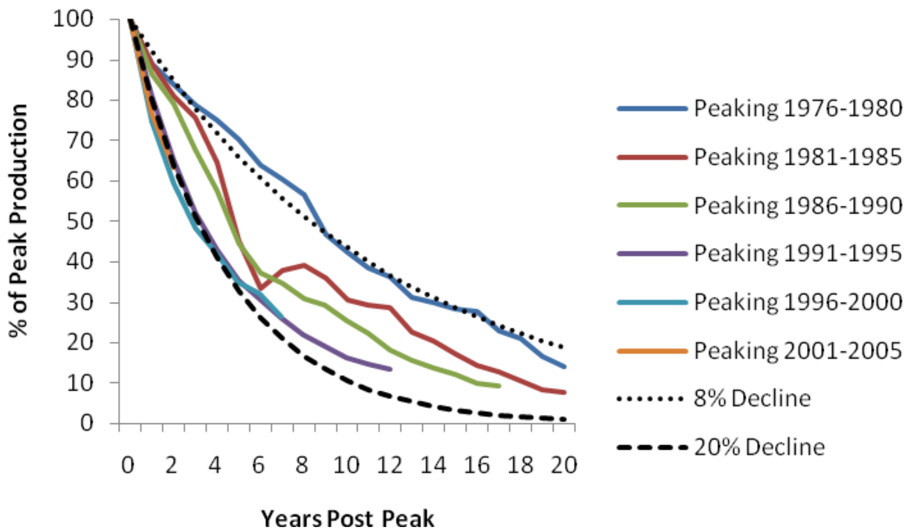


Table 3.1: Mean field size for each interval of peaking fields in Figure 3.7

Fields Peaking Between:	**Mean Field Size (MMbbl)**
1976-1980	874
1981-1985	582
1986-1990	405
1991-1995	88
1996-2000	80
2001-2005	70

These data show that older fields in the UKCS have smaller rates of decline, but they do not tell us why. The three giants of Forties, Brent and Ninian are in the two oldest tranches, so the data may indicate that larger fields, which are usually found first, decline at slower rates. Alternatively, changes in the economic and technological context with time might have changed the development of later fields, so that they were planned for faster production, with higher peaks and steeper declines than similar-sized older fields.

In a detailed study of decline rates in the UKCS, Kemp and Kasim (2005) compared several models of decline for a sample of 235 fields. Their key findings were:

- The logistic model of decline provided a better fit (on the basis of R^2) than either the linear or exponential models in the majority of cases (Table 3.2.). Decline rates range from 1.5% for the logistic model in 1973 to 15% for the exponential model in 2000. In general, the exponential model gives higher estimates of decline rates than the logistic model.

- Many fields were better fit by the sum of two or more logistic curves, indicating shifts in the pattern of decline in response to investment and other factors

- The exponential model performed poorly, raising questions about its position as the preferred decline rate model. This implies that forecasts of future production and estimates of URR that rely upon the exponential model may be misleading.

- Decline rates appear to increase with field vintage, with younger fields having higher decline rates (Figure 3.8).

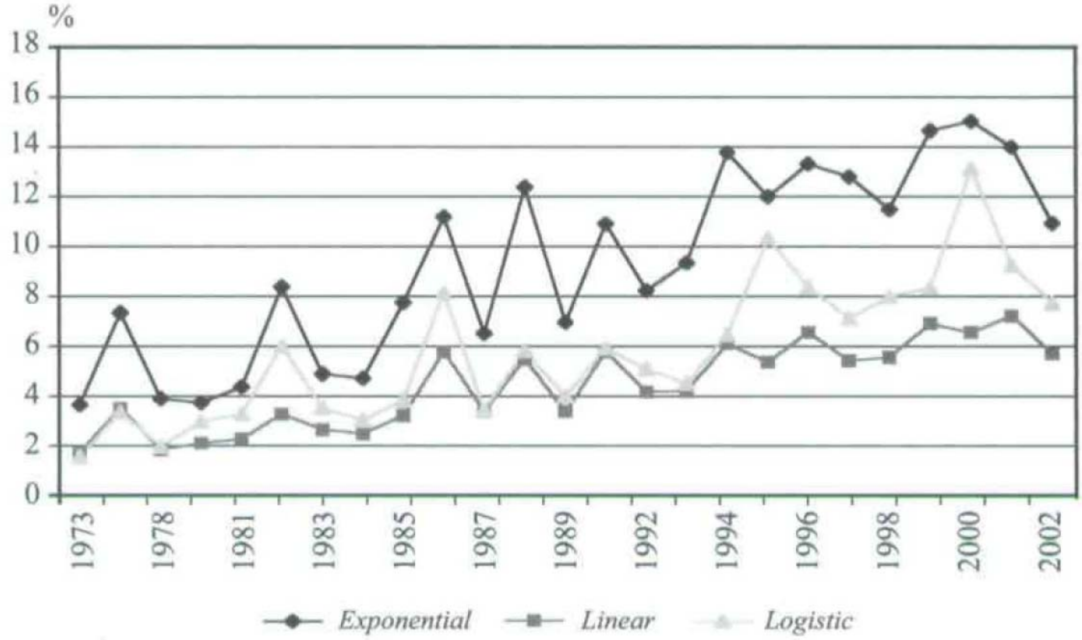
- Investment in in-fill drilling and EOR significantly reduced decline rates. But investment in younger fields had a greater effect on slowing decline rates than investment in older fields. The effect of investment was largely independent of location, resource type, size of field, water depth and the size of investment.

Table 3.2: Best fit models as percentage of fields in vintage

Field Vintage By First Production	**Logistic**	**Linear**	**Exponential**
Pre 1970	66.7	33.3	0.0
1970's	77.8	22.2	0.0
1980's	63.5	26.9	9.6
1990's	65.3	29.1	5.7
2000's	81.8	18.2	0.0
Total	*67.3*	*27.0*	*5.8*

Source: Kemp and Kasim (2005)

Figure 3.8: UKCS – Annual mean production decline rates by year of commencement



Source: : Kemp and Kasim (2005)

4 Global average decline rates

Three recent studies have estimated decline rates from a globally representative sample of fields. While each study uses a different sample, they all include the giant fields which account for over half of global production. Collectively, these three studies greatly improve our understanding of decline rates and provide an important reference for future forecasts of global oil supply. However, there are a number of inconsistencies both within and between these studies and comparison is hampered by competing definitions and different approaches to production weighting.

The basic features of each study are summarised in Table 4.1. Each study follows the IEA (2008) in defining super-giant fields as having a URR exceeding 5 Gb, 'giant' fields as having a URR in the range 0.5-5 Gb and 'large' fields as having a URR in the range 0.1-0.5 Gb. As discussed in Sorrell and Speirs (2009), around 100 giant and super-giant fields account for up to half of the global production of crude oil, while up to 500 fields account for two thirds of cumulative discoveries. Most of these fields are relatively old, many are well past their peak of production and most of the rest will begin to decline within the next decade or so. The rate of production decline from these fields is therefore of critical importance for future global supply.

Table 4.1 Comparison of global decline rate studies

	IEA	**Hook *et al.***	**CERA**[1]
No. of fields in sample	651 (54 supergiant, 263 giant, 334 large)	331 (all giant)	811 (400 large and above)
No. post-peak fields	580[1, 2]	261[3]	-
% of total production of crude oil in sample	~58%	~50%	~66%
Cumulative discoveries of crude oil in sample	1241 Gb	1130 Gb	1155 Gb
Definition of plateau	Production >85% of peak	Production >96% of peak	Production >80% of peak
Definition of onset of decline	After year of peak production	After last year of plateau	After last year of plateau
Production weighting	Cumulative production[4]	Annual production	Annual production

Source: IEA(2008), CERA (2008) and Höök, *et al.*(2009; 2008; 2009a; 2009b).
Notes:
- 101 fields in plateau (production >85% of peak), 117 fields in 'phase 1 decline' (production >50% of peak), 362 fields in 'phase 3' decline (production <50% of peak)
- 387 onshore, 264 offshore, 185 OPEC and 466 non-OPEC.
- 261 onshore, 214 offshore, 143 OPEC and 188 non-OPEC.
- IEA weights by annual production when estimating historical trends in decline rates.

1.10 Key results from the three studies

These studies estimate the production-weighted aggregate decline rate of their sample of post-peak fields to be 5.1%/year (IEA), 5.5%/year (Hook *et al.*) and 5.8%/year (CERA) (Table 4.2). The production-weighted decline is less than the simple average decline because fields with higher production tend to be larger and decline slower. The studies also agree that:

- Decline rates are lower for OPEC fields and particularly for Middle East fields (Table 4.2). This is partly reflects differences in average size, but also quota restrictions and disruptions from political conflict.
- Decline rates are higher for offshore fields (Table 4.2). These tend to be produced at higher rates in order to recover their higher fixed costs, leading to higher peaks, shorter plateaus and steeper declines.
- Decline rates are lower for larger fields and are particularly low for the super-giant fields in the Middle East (Table 4.3). Large fields reach their peak later than small fields, but also produce a greater proportion of their URR during the decline phase (IEA, 2008).
- Decline rates are higher for fields in the later stages of decline (Table 4.4). This largely reflects the mix of fields within each stage rather than the evolution of decline rates from individual fields over time.[5]

Table 4.2 Estimates of production-weighted aggregate decline rates for samples of large post-peak fields

Parameter	IEA	Höök, *et al.*	CERA
Onshore	4.3	3.9	-
Offshore	7.3	9.7	-
Non-OPEC	7.1	7.1	-
OPEC	3.1	3.4	-
Total	**5.1**	**5.5**	**5.8**

Source: IEA(2008), CERA (2008) and Höök*, et al.*(2009; 2008; 2009a; 2009b).
Note: Studies use different data sets, definitions and methods of production weighting. Details missing for CERA since we do not have access to the full study.

Table 4.3 IEA estimates of aggregate production-weighted decline rates for different sizes of post-peak field

	Total	Supergiant	Giant	Other
Onshore	4.3	3.4	5.6	8.8
Offshore	7.3	3.4	8.6	11.6
Non-OPEC	7.1	5.7	6.9	10.5
OPEC	3.1	2.3	5.4	9.1
All fields	**5.1**	**3.4**	**6.5**	**10.4**

Source: IEA(2008)
Note: The production-weighted decline rate is 1.4% in decline phase 1, 3.6% in decline phase 2 and 6.7% in decline phase 3. The production-weighted sample average for post-plateau fields is 5.8%.

[5] For example, the very low average decline rate for 'decline phase 1' (peak to end of plateau) is largely due to the low decline rate of the world's largest field - Ghawar in Saudi Arabia.

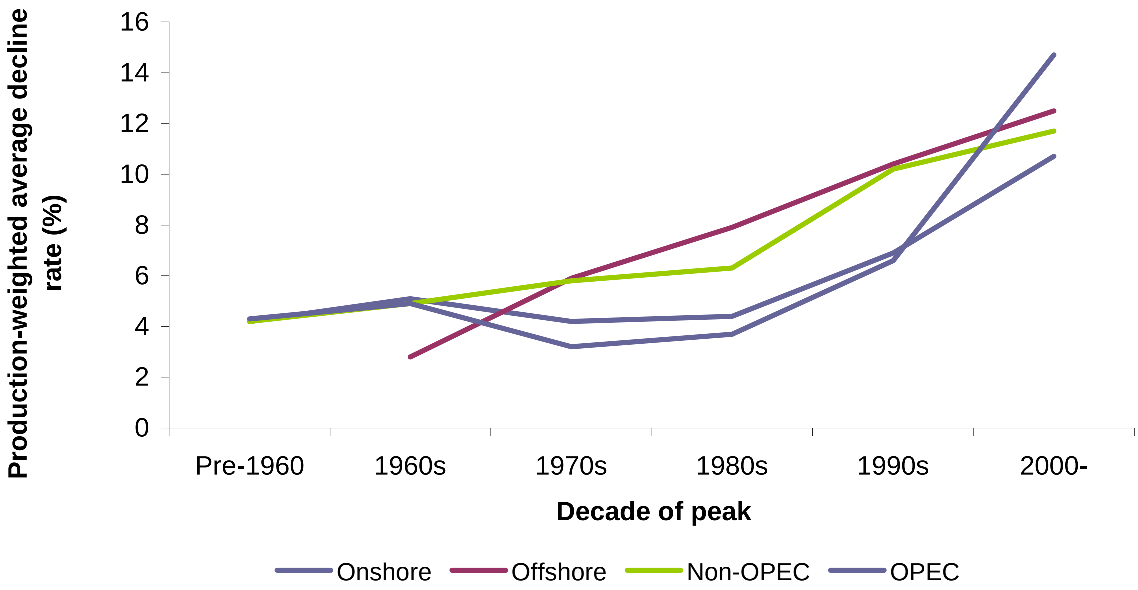
Table 4.4:Production-weighted average decline rates by decline phase (%)

	Decline Phase 1 (peak to end of plateau)	Decline Phase 2 (plateau to 50% of peak)	Decline Phase 3 (50% of peak to latest year)	Total
Super-Giant	0.8	3.0	4.9	3.4
Giant	3.0	3.7	7.6	6.5
Large	5.5	7.2	11.8	10.4
All fields	**1.4**	**3.6**	**6.7**	**5.1**

Source: IEA WEO 2008

Importantly, both the IEA and Höök, *et al.* find decline rates to be significantly higher for newer fields (Figure 4.1 and Table 4.5). The IEA argues that newer fields built up more quickly to a higher plateau that is maintained over a shorter period of time, but Höök, *et al.* (2009a) show that the length of plateau for giant fields has *increased* together with the proportion of the remaining resources produced prior to peak. They argue that new technology allows the plateau to be maintained for extended periods of time, but at the cost of more rapid decline following the peak (see also Gowdy and Roxana, 2007). The collapse of production at Canterell following extensive use of nitrogen injection is a notable example.

Figure 4.1 Evolution of production-weighted giant oilfield decline rates over time



Source: Höök, *et al.*(2009b)
Note: Figures for most recent decade less certain since sample of fields is much smaller

Table 4.5: Production-weighted average post-peak decline rates by vintage (%)

	Pre-1970's	1970's	1980's	1990's	2000's	Average
OPEC	2.8	3.5	4.6	7.5	5.0	3.1
Non-OPEC	5.9	6.8	8.3	11.6	14.5	7.1
All fields	**3.9**	**5.9**	**7.9**	**10.6**	**12.6**	**5.1**

Source: IEA (2008)
Note: Vintage is year of first production

1.11 Global average decline rates

The above figures are likely to underestimate the global average decline rate for *all* post-peak fields since the mean size of each sample of fields is greater than that of the global population. Under the optimistic assumption that that decline rate for smaller fields is the same as that for the sample of large fields (10.4%), the IEA estimate a production-weighted global average decline rate of **6.7%/year** for all post-peak fields.

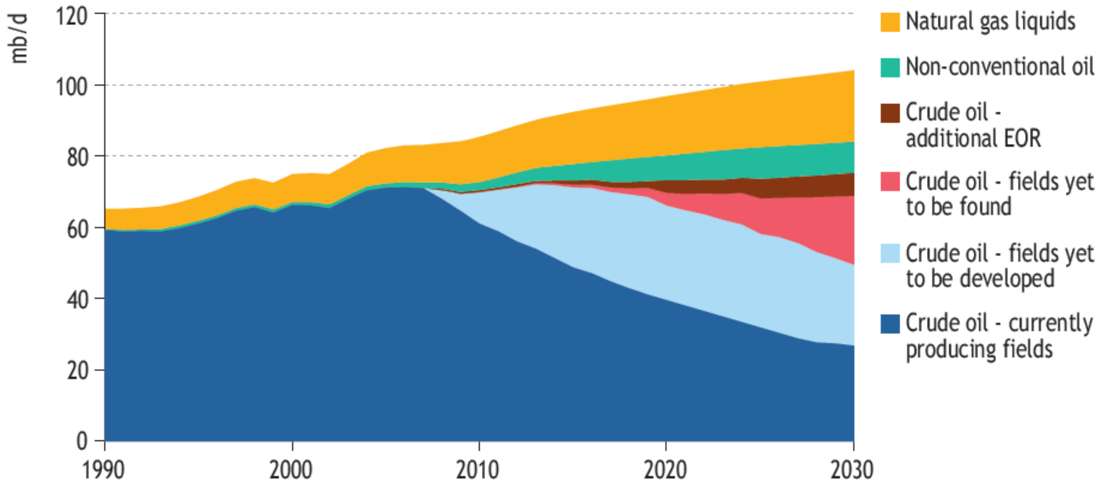
To prevent overall global production from declining, this loss of production needs to be replaced by a combination of:

- increased output from existing fields through investment in EOR or related techniques,
- the development of 'fallow' fields (i.e. fields that have been discovered but have yet to be brought into production); and
- the discovery and development of new fields.

To estimate the additional capacity required each year it is necessary to know either the proportion of production from post-peak fields, or the production-weighted aggregate decline rate of *all* fields, including those in plateau and build-up. Oddly, both of these figures are absent from the IEA study and they appear to calculate the capacity requirements incorrectly. Specifically, the IEA appear to multiply the production-weighted aggregate decline rate of post-peak fields (6.7%) by global crude oil production (70 mb/d) to estimate an annual loss of output of 4.7 mb/d. But the correct procedure is to multiply by the production-weighted aggregate decline rate of *all* fields, including those in plateau and build-up.

The IEA provide this figure for OPEC (3.3%) and non-OPEC fields (4.7%), but not for the world as a whole. However, by weighting by the 2007 production of each region, we estimated the global average figure to be ~**4.1%/year.** This compares to CERA's estimate of 4.5%/year and also appears consistent with the IEA's graphs (Figure 4.2). This implies that approximately 3 mb/d of production capacity needs to be added each year by new investment, simply to maintain production flat. This is equivalent to adding the production capacity of Saudi Arabia every three years.

Figure 4.2 IEA WEO 2008 projection of future world oil production



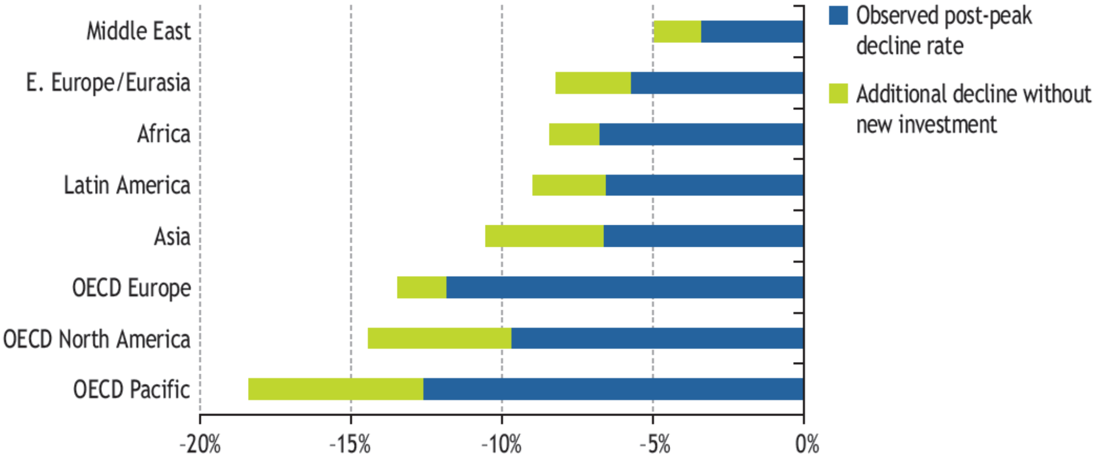
Source: IEA (2008)

The IEA (2008) also estimate the *natural* decline rate of their sample of fields – or the decline rate that would have occurred in the absence of extra capital investment. To do this they 'strip out' the estimated impact of the investment in these fields over the past five years. Given the large amount of judgement required and the deficiencies of the data, the results are presented as indicative only.

Over the period 2003-2007, the IEA estimate the global average production-weighted natural decline rate of *all* post-peak fields to be 9.0%/year. This is 2.3% higher than the estimated observed decline rate of those fields (6.7%/year). Figure 4.3 illustrates how these rates vary between different oil producing regions.

The IEA also found a trend towards increasing natural decline rates over time. The global average was estimated to have increased from 8.7%/year in 2003 to 9.7%/year in 2007. This is probably the result of an increasing share of production deriving from younger, smaller and offshore fields that have higher decline rates (in part because of the fewer opportunities for infill drilling). In order to maintain observed decline rates, current investment must also be maintained. The global economic recession of 2008-09 has led to a reduction investment which will contribute to observed decline rates coming closer to the natural decline rates.

Figure 4.3 Estimates of regional average natural and observed decline rates of post-peak fields



Source: IEA (2008)

1.12 Future decline rates

A critical question for supply forecasting is how global average decline rates may be expected to develop in the period to 2030. Most existing fields should enter decline over this period, with a growing proportion of production from younger, smaller and offshore fields. The IEA expects the production-weighted global average decline rate of post-peak fields to increase to 8.5%/year by 2030, leading to an estimated loss of 61% of current capacity (43 mb/d). However, Höök, *et al.* (2009a) consider this estimate to be optimistic, given the trend towards higher decline rates in the giant fields and the observed tendency for the production-weighted decline rate to converge on the (higher) average rate (Höök and Aleklett, 2008).

In summary, the global average decline rate of post-peak fields is at least 6%/year and the corresponding overall decline rate is at least 4%/year. Both are on an upward trend as more giant fields enter decline, as production shifts towards smaller, younger and offshore fields and as changing production methods lead to more rapid post-peak decline. Significant investment is needed simply to offset the underlying natural decline rates and if this is not forthcoming (for example, as a result of the economic slowdown) decline rates will increase. While future trends in decline rates are difficult to forecast, a case could be made that the IEA's assumptions are optimistic. If so, more than two thirds of current crude oil production capacity will need to be replaced by 2030, simply to keep production constant. Given the long-term decline in new discoveries (Figure 2.8), this will present a major challenge even if 'above-ground' conditions prove favourable.

5 Depletion rates

Decline rates are a measure of the change in the rate of production of a field from one year to the next. They should not be confused with *depletion rates* which are a measure of the rate at which the recoverable resources of a field or region are being produced. The depletion rate is defined as the ratio of annual production to some estimate of recoverable resources, where the latter could be the URR, the remaining 1P reserves or the remaining 2P reserves. The depletion rate is simply the inverse of the more familiar reserve to production (R/P) ratio, although the latter is normally defined in relation to 1P reserves. While decline rates can be measured precisely, depletion rates are based upon uncertain resource estimates which vary between sources and over time - with higher resource estimates leading to lower estimates of depletion rates.

1.13 Giant field depletion rates

Höök (2009) has demonstrated the close links between depletion rates and decline rates. He shows how the depletion rate of a field generally increases during the build-up and plateau phase as resources deplete. Once decline begins, the depletion rate either remains constant or falls - provided the resource estimate remains unchanged. If decline is exponential the depletion rate equals the decline rate, while if decline is hyperbolic the maximum depletion rate is reached just prior to the onset of decline. Höök, *et al.* (2009b) show that the maximum depletion rate of giant oil fields typically falls within a relatively narrow band, with a production-weighted mean of 7.2% (Table 5.1). As with decline rates, the maximum depletion rate is higher for offshore fields and lower for OPEC fields.

Höök, *et al.* (2009b) also estimate the *depletion at peak*, or the proportion of URR produced at the onset of field decline. The production-weighted mean of their sample of giant fields is 37%, with the average being higher for offshore fields and lower for OPEC fields. A similar analysis is conducted by the IEA (2008) who find values ranging from 15% for large fields to 25% for small offshore fields. These results demonstrate that most fields reach their peak when less than half - and often less than one third - of their recoverable resources have been produced. The IEA estimates that giant fields are on average 48% depleted, with the regional average varying from 37% in the Middle East to 78% in North America.

Table 5.1 Estimated depletion at peak and depletion rate at peak for giant oil fields

	Depletion at peak	**Depletion rate at peak**
All land	34.1%	5.8%
Offshore	44.0%	11.0%
Non-OPEC	37.4%	8.7%
OPEC	31.5%	5.3%
All fields	**36.8%**	**7.2%**

Source: Höök, *et al.* (2009b)
Notes:
Depletion rate = Ratio of annual production to remaining resources
Depletion = Ratio of cumulative production to estimated ultimately recoverable resources
All figures production-weighted

1.14 Regional depletion rates

Depletion and depletion rates can also be estimated at the regional level, although the uncertainty on the resource estimates will necessarily be greater. Of particular interest are the values at peak for the countries that have passed their peak of production. Figure 5.1 shows these estimates for 55 post-peak countries. The estimates of regional URR are taken from the authoritative and widely cited global study by the US Geological Survey (USGS, 2000).[6] Post-peak countries for which URR estimates were not available are excluded. It is important to note that timing of the peak of production for many of these countries may be influenced by factors other than physical depletion.

Using these estimates, we estimate a simple mean for *depletion at peak* of 25%, a production-weighted mean of 26% and a maximum of 55%. In other words, most countries appear to have reached their peak well before half of their recoverable resources have been produced. Similarly, we estimate the mean *depletion rate at peak* for these countries to be 3.4%, the production-weighted mean to be 2.3% and the maximum to be 4.8% - for Argentina.[7] However, the average depletion rate over the full production cycle is typically lower than the maximum rate. At present, the global average depletion rate is approximately 1.2%.

This analysis shows that there are constraints on both the rate of depletion for a field or region and the proportion of the URR that can be produced prior to the peak. Hence, both measures can provide a useful reality check on supply forecasts (Aleklett, *et al.*, 2009). Specifically, a forecast that implies depletion rates that are significantly higher than experienced in other oil-producing regions will require careful justification. The same applies to forecasts that that delay the peak of production until significantly more than half of the URR has been produced. However, the usefulness of these 'rules-of-thumb' depends very much upon the accuracy of the estimated URR.

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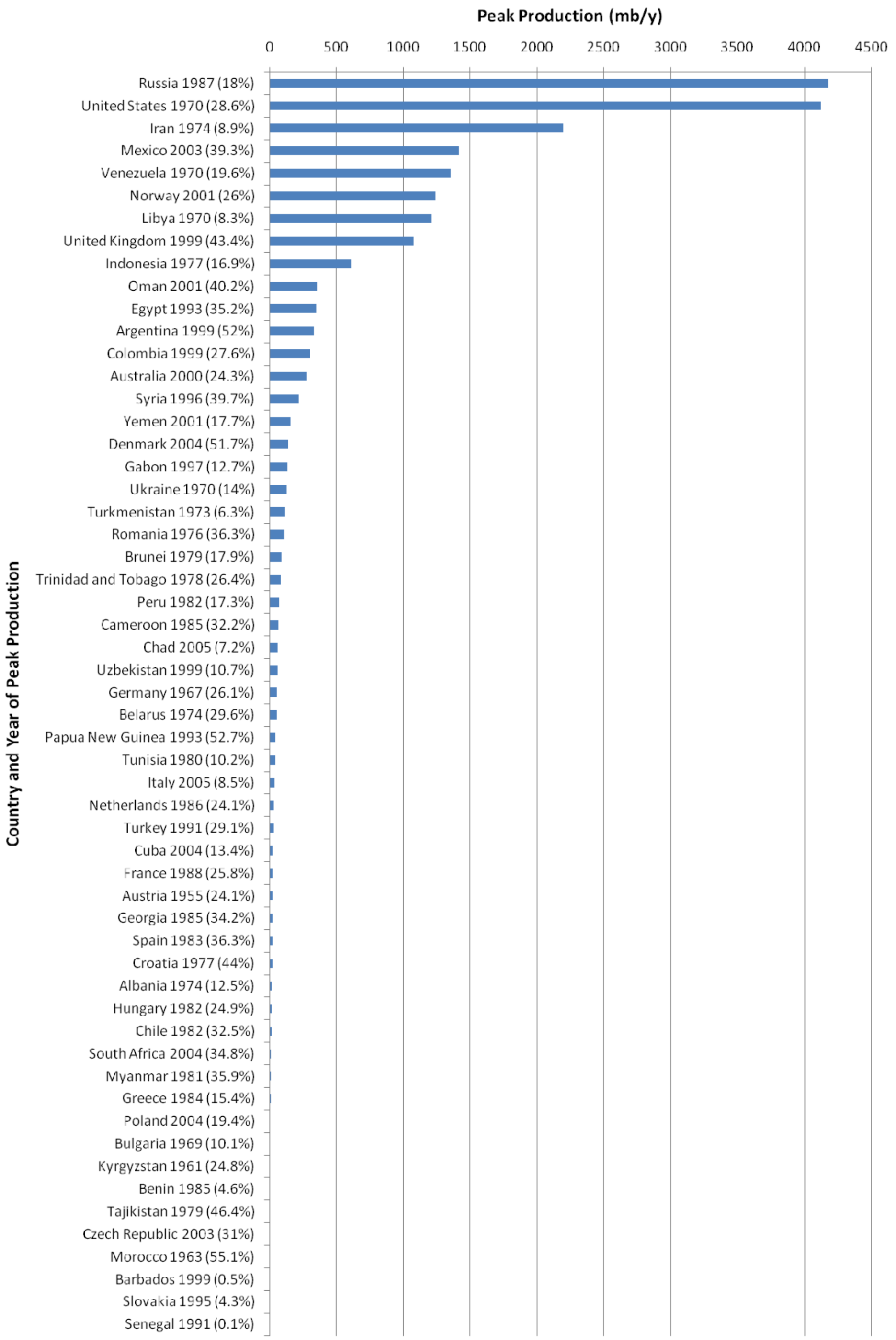
[6] Since the USGS only estimate reserve growth at the global level, this was allocated between countries in proportion to their estimated URR excluding reserve growth.
[7] We estimate the depletion rate at peak for the UK to be 4.4% assuming a URR of 43 Gb. In contrast, Aleklett, *et al.*(2009) estimate a depletion rate at peak of 6.9% assuming a lower URR of 35 Gb. This discrepancy highlights the sensitivity of these estimates to the assumed URR.

Depletion rates can also provide a useful bridge between estimates of the rate of reserve growth and/or new discoveries and the rate of production. While it is common to estimate these in Gb/year, to translate this into a feasible rate of production it is necessary to multiply by an assumed depletion rate. If the product of the two is less than the capacity anticipated to be lost through production decline, then aggregate production in a region may be expected to fall. For example, a global average decline rate of 4.1% implies an annual loss of 2.9 mb/d or ~1.0 Gb/year of production capacity. This capacity needs to be replaced by a combination of developing fallow fields, reserve growth at existing fields and new discoveries simply to maintain production at current levels. Using a peak depletion rate of ~5.0%/year, this leads to a requirement for ~20 Gb/year from these sources if global production is to be maintained. If instead the depletion rate of these resources is only 1.2%/year (the current global average for all production), ~80 Gb/year is required. As demand grows and decline rates increase in the medium to long-term, either the rate at which reserves are added from these sources, or the rate at which they are depleted needs to increase. However, the former runs counter to the trend of declining discoveries while the latter is subject to physical, engineering and economic limits.

Figure 5.1 Peak production, peak year and depletion rates of post-peak producers



Source: BP (2008); USGS (2000)
Note: Shows peak year and estimated percentage of USGS (2000) estimate of URR that was produced by the date of peak.

6 Summary

The main findings of this report are as follows.

- Oil field decline is a universal and natural physical phenomenon, but the precise decline rate will be influenced by a variety of geological, technical and economic factors including in particular the use of enhanced recovery methods.
- The decline of single fields is commonly approximated by an exponential model, but this is not always often a good fit to the data and it can underestimate production during the later stages of a field's life. Alternative models include harmonic, hyperbolic and logistic decline.
- Decline rates can be estimated for individual wells and fields and also for larger regions such as, basins and countries. Regional decline rates can either include or exclude the production from fields which have not yet peaked. The context is important and must be specified.
- Decline rates may be estimated using time-series data on the production from individual fields, but this is rarely available in the public domain. In particular, there is little reliable data available on the 14 or so 'supergiant' fields which produce more than 500 kb/d and whose production is of such critical importance for future global supply.
- There is considerable variability in decline rates, and the rates estimated for one region or group of fields may not be applicable to another region or group of fields or even for the same region or group at a later point in time.
- The rate of decline of production from existing fields is of greater importance for future supply than increases in demand. The global average decline rate of post-peak fields is at least 6%/year and the corresponding overall decline rate is at least 4%/year. Both are on an upward trend as more giant fields enter decline, as production shifts towards smaller, younger and offshore fields and as changing production methods lead to more rapid post-peak decline.
- These global decline estimates imply that some 3 mb/d of production is lost each year. This is the amount of new production that needs to come on-stream from new fields or enhanced recovery at existing fields, simply to maintain production at current levels. A greater volume of new production needs to come on-stream to accommodate demand growth. More than two thirds of current crude oil production capacity may need to be replaced by 2030, simply to keep production constant. At best, this is likely to prove extremely challenging.
- There are constraints upon the rate of depletion of a field or region, although estimates of these rates are contingent upon uncertain estimates of the URR. Historically, the maximum observed depletion rate has been ~6% for onshore giant fields and ~11% for offshore giant fields. Using URR estimates from the USGS, the maximum observed depletion rate for regions has been ~5%, although the average depletion rate over the production cycle is typically much lower than this. Hence, supply forecasts that assume or imply higher depletion rates are likely to require careful justification.

- To date, most giant fields and most countries appearing to have reached their peak well before half of the recoverable resources have been produced. Hence, supply forecasts that assume or imply the production of more than half the resources prior to the peak will also require careful justification. In addition, development patterns that delay the peak may be associated with more rapid post-peak decline.
- Depletion rates can be used to estimate the required rate of resource additions from new discoveries and enhanced recovery. If the average depletion rate for these resources was as high as previously seen in any oil-producing region, at least 20 Gb/year would be needed to compensate for production decline. In practice, a significantly higher rate of resource additions is likely to be required. Moreover, as demand grows and/or decline rates increase, this figure will need to increase.

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