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The future of oil supply

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Introduction

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Abundant supplies of oil form the foundation of modern industrial economies, but the capacity to maintain and grow global supply is attracting increasing concern. Some commentators forecast a peak in the near future and a subsequent terminal decline in global oil production, while others highlight the recent growth in 'tight oil' production and the scope for developing unconventional resources. There are disagreements over the size, cost and recoverability of different resources, the technical and economic potential of different technologies, the contribution of different factors to market trends and the economic implications of reduced supply. Few debates are more important, more contentious, more wide-ranging or more confused. This paper summarizes the main concepts, terms, issues and evidence that are necessary to understand the 'peak oil' debate. These include: the origin, nature and classification of oil resources; the trends in oil production and discoveries; the typical production profiles of oil fields, basins and producing regions; the mechanisms underlying those profiles; the extent of depletion of conventional oil; the risk of an approaching peak in global production; and the potential of various mitigation options. The aim is to introduce the subject to non-specialist readers and provide a basis for the subsequent papers in this Theme Issue.

1. Introduction

Abundant supplies of cheap natural liquid fuels form the foundation of modern industrial economies, and at present the vast majority of these fuels are obtained from so-called 'conventional' oil. Oil accounts for more than one third of global primary energy supply and more than 95% of transport energy use—a critically important sector where there are no easy substitutes. Our familiarity with oil can obstruct recognition of how

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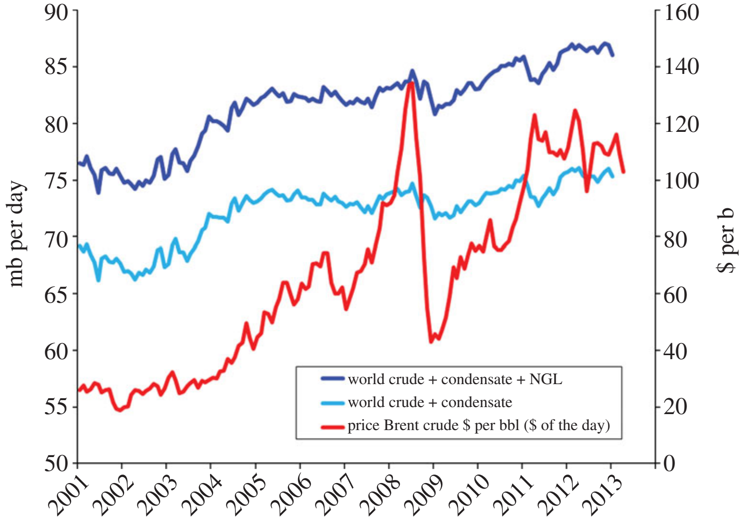

Figure 1. Monthly average crude oil price (right axis) and global oil supply (left axis). Source: US Energy Information Administration. For oil definitions see figure 2 and box 1. Oil supply has been slow to respond to the doubling of crude oil prices since mid-2005. This is partly because of political conflicts in key regions (e.g. Iraq) and the strategies of key exporters (e.g. Saudi Arabia), but largely reflects the growing lead times on new projects (5–10 years) and the increasing difficulty and cost (up 50% since 2005) of finding and developing new resources. (Online version in colour.)

remarkable a substance it is: oil took millions of years to form from the remains of marine and other organisms; it is only found in a limited number of locations where a specific combination of geological conditions coincide; it possesses an unequalled combination of high energy per unit mass and per unit volume; and it is both highly flexible and easily transportable. One litre of diesel contains enough energy to move a 40 tonne truck three kilometres—a feat that would be impossible with battery-electric propulsion for example. Nonetheless, despite heavy taxation in most countries and historically high global oil prices, a litre of diesel remains cheaper than a cup of coffee.

Oil is a finite and rapidly depleting fossil resource, and the capacity to maintain and grow supply has been a recurrent concern for over 50 years. During the first decade of this century, an increasing number of commentators began forecasting a near-term peak and subsequent terminal decline in the global production of conventional oil—so-called ‘peak oil’. This process was forecast to lead to substantial and sustained disruption of the global economy, with alternative sources of energy being unable to ‘fill the gap’ at acceptable cost on the time scale required. Countering this, other commentators argued that rising oil prices would stimulate the discovery and enhanced recovery of conventional oil, the development of ‘non-conventional’ resources such as oil sands, and the diffusion of substitutes such as biofuels and electric vehicles, without economic disruption. In support of their arguments, the first group cite the plateau in crude oil production since 2005 and the associated rise in oil prices (figure 1), while the latter group cite the recent rapid growth in US tight oil production. But despite these differences, there is a growing consensus that the era of cheap oil has passed and that we are entering a new and very different phase.

The contemporary debate over peak oil has its roots in long-standing disputes between ‘resource optimists’ and ‘resource pessimists’ that can be traced at least as far back as Malthus [1]. These disputes are underpinned by the differing perspectives of natural and social scientists, but in the case of oil they are greatly amplified by the difficulties in accessing the relevant data, the unreliability of the data that are available and the pervasive influence of powerful economic and political interests. Moreover, a full appraisal of the challenge posed by oil depletion must extend beyond geological assessments of resource size to include the potential of different extraction technologies, the cost of production of different resources, the operation of global fuel markets, the geopolitics of oil security, and the technical and economic potential for both efficiency improvements and resource substitution in multiple end-use sectors. In practice, few studies can adequately address this complexity.

In this paper, we introduce the data, concepts, terms and evidence that underlie this debate and provide a foundation and context for the papers that follow. The paper is structured as follows. Section 2 summarizes the origin, nature and classification of different types of oil resources, while §3 describes the mechanisms of oil production, the global estimates of resources and reserves and the trends in oil production and discoveries. Section 4 examines the typical production profiles of oil fields, basins and producing regions and shows how these underpin concerns about future supply. Section 5 summarizes the arguments for and against a near-term peak in global oil production and briefly evaluates some mitigation options. Finally, §6 introduces the papers in this Theme Issue.

2. Oil formation and classification

Petroleum comprises all naturally occurring hydrocarbons in rocks, and originates from organic materials (most commonly marine organisms) incorporated into sedimentary rocks.[1] These are termed *source rocks* and are typically fine-grained mudstones or shales. The subsidence and burial of these rocks over geological time raises their temperature and pressure and commences the process of organic *maturation*. This process first converts the fossilized organic material into an insoluble mixture of extremely large organic molecules, termed *kerogen*, and then as maturation increases, progressively breaks off smaller hydrogen-rich molecules which form a liquid, leaving an increasingly carbon-rich and refractory kerogen residue. Significant generation of liquid oil typically commences at temperatures around 70°C and continues until 120–160°C, a range called the *oil window*. Higher temperatures may cause further decomposition of remaining kerogen to produce gaseous C1–C5 hydrocarbons (methane–pentane) and also thermal breakdown of previously generated oil into progressively smaller molecules. The current rate of global oil generation has been estimated at no more than a few million barrels[2] per year [3], compared to global consumption of some 30 billion barrels per year. Crude oil production grew at approximately 1.5% per year between 1995 and 2005, but then plateaued with more recent increases in liquids supply deriving from natural gas liquids (NGLs; see box 1), oil sands and tight oil. These trends are expected to continue.

Mature source rock in contact with adjacent porous rocks may expel generated petroleum down the fluid pressure gradient. If oil cannot be expelled from its source rock it is described as *tight oil*, a class which includes all oil trapped in impermeable rocks. Expelled oil is less dense than water so will tend to slowly migrate upwards through permeable rocks, replacing pore water. Oil may migrate to the surface and emerge as a *seep*, but if it reaches an impermeable barrier or *seal*, in a structure forming a *trap*, it may accumulate in place as a *pool* within a *reservoir rock*. Reservoir rocks are primarily characterized by their porosity and permeability, but also by their thickness, continuity, uniformity and lithology (mineralogy, composition and structure). Typical impermeable seal lithologies include shale and salt. An oil pool usually has water-saturated rock underlying it and possibly a *gas cap* overlying it. An oil *play* is a specific set

[1] Alternative, non-biological ('abiogenic') origins for petroleum have also been proposed. These require a deep-Earth source of primordial methane which is converted, by Fischer–Tropsch reactions, into longer chain alkanes and other molecules, either in the upper mantle (the so-called Russian theory) or in the upper crust (the so-called Thomas Gold theory). These theories have been generally discredited, both on chemical and thermodynamic grounds and from considerable empirical evidence, such as the presence of biomarker molecules in oil that are directly traceable to biological precursors [2].

[2] Oil production and resources are commonly measured in volumetric terms, despite significant variations in specific gravity and energy content. One barrel (b) is approximately 158 litres and may weigh between 0.12 and 0.16 tonnes. Commonly used multiples include thousand (kb), million (mb) and billion barrels (Gb). A 'barrel of oil equivalent' (boe) is a quantity of fuel containing the average thermal energy of a barrel of oil, defined as 6.1 GJ (higher heating value).

Box 1. Categories of hydrocarbon liquids.

— *Crude oil* is a heterogeneous mix of hydrocarbons that remain in liquid phase when extracted to the surface. Crude oil is commonly classified by its density, measured in degrees of *API gravity* with higher API indicating lighter oil.[3] Industry definitions vary, but heavy oil is typically less than 20° API.

— *Condensate* is a very light, volatile liquid, typically 50–75° API, which condenses from produced gas when it cools at the surface. Condensate is generally mixed with crude oil and produced volumes are rarely reported separately.

— *Natural gas liquids* (*NGLs*) is a generic term for the non-methane fraction of natural gas (mostly ethane to pentane) that is either liquid at normal temperatures and pressures, or can be relatively easily turned into a liquid with the application of moderate pressure.

— *Extra-heavy oil* is crude oil with an API gravity of less than 10° and typical viscosity more than or equal to 10 000 centipoise.[4] Most current production is from the Orinoco belt in Venezuela.

— *Oil sands* (or tar sands) are a near-surface mixture of sand, water, clay and bitumen, where the latter has an API gravity less than 10° and typical viscosity 10 000–1 000 000 centipoise. The bitumen is the degraded remnant of conventional oil when oil in near-surface accumulations has been altered by the loss of the lighter hydrocarbon molecules, primarily by bacterial oxidation and biodegradation and by dissolution in groundwater. The remaining oil becomes progressively richer in bitumen, denser and more viscous. Most current production is from Alberta and uses surface mining to depths up to 65 m. The bitumen can be diluted or upgraded to a synthetic crude for transport by pipeline.

— *Tight oil* (or shale oil) is light crude oil contained in shale or carbonate rocks with very low permeabilities that can be produced using horizontal wells with multi-stage hydraulic fracturing. Most current production is from the Bakken and Eagle Ford shales in the USA.

— *Kerogen oil* (or ‘oil shale’ oil) is the oil obtained from processing the kerogen contained in fine-grained sedimentary rocks. This involves mining and crushing the rock, heating for prolonged periods at high temperatures, driving off a vapour and distilling. *In situ* processes are also under development, but neither approach is likely to be economic for the foreseeable future.

— *Gas-to-liquids* (*GTLs*) are derived through the liquefaction of methane using the Fischer–Tropsch process. This involves steam reforming of natural gas to produce carbon monoxide and hydrogen followed by catalysed chemical reactions to produce liquid hydrocarbons and water.

— *Coal-to-liquids* (*CTLs*) are derived either by pyrolysis of coal (low yield) or by gasification followed by a Fischer–Tropsch process (high yield).

— *Biofuels* are transport fuels derived from biological sources. At present, these consist of either ethanol produced through the yeast fermentation of sugar or starch-rich arable crops, or biodiesel derived from seed oils. Second generation cellulosic biofuels using non-food feedstocks are also under development.

of geological conditions, defined by source, maturity, migration route, reservoir, trap and seal, which is conducive to the existence of oil pools within a geographically defined region.

[3] API gravity is defined as (141.5/specific gravity) – 131.5. API gravity therefore rises as the specific gravity falls.

[4] Water at a temperature of 21°C has a viscosity of approximately one centipoise.

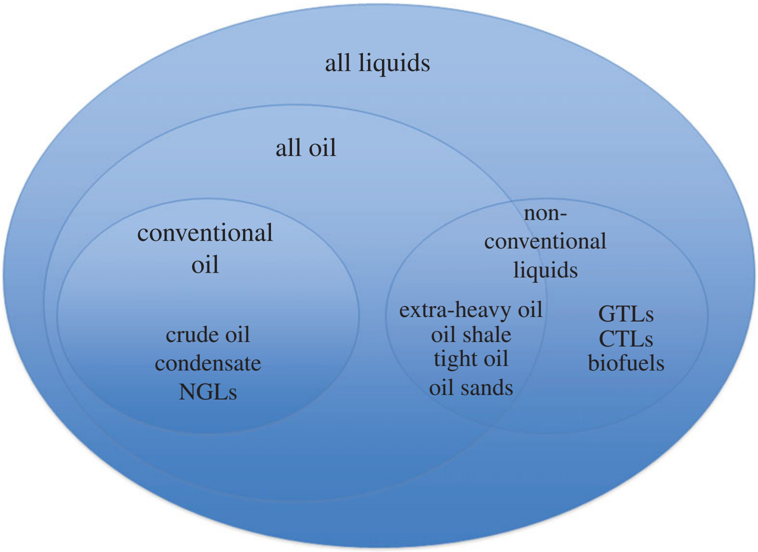

Figure 2. Classification of hydrocarbon liquids. (Online version in colour.)

An oil *field* may consist of one or more separate pools. Generally speaking, oil fields are accumulations large enough to be spatially defined, but are not necessarily economically viable. There is a complete size spectrum of accumulations ranging up to the giant and supergiant fields, which are usually defined as holding more than 500 million and 5000 million barrels of recoverable oil, respectively. The size distribution of commercial fields is fairly well known [4], but the distribution of smaller fields is not, in part because these are neither deliberately sought nor always announced when encountered.

In both individual plays and larger regions (*petroleum basins*), the majority of oil resources tend to be located within a small number of large accumulations. For example, although there are up to 70 000 producing oil fields in the world, around 500 giant and supergiant fields account for two-thirds of all the oil that has ever been discovered [4]. As discussed later, this basic physical characteristic of oil resources is of critical importance for future supply.

Oil resources are commonly classified into different categories on the basis of physical oil and rock properties, extraction technology or location, but there are inconsistencies in the terminology used. Figure 2 summarizes our classification, while box 1 expands upon these definitions. We define *conventional oil* as crude oil, condensate and NGLs and *non-conventional oil* as tight oil, extra-heavy oil, oil sands and kerogen oil. Since tight oil is similar in chemical composition to crude oil (while the other non-conventional oils are not), it could equally be classified as conventional. We classify it as non-conventional here, to emphasize the fact that tight oil is a new and rapidly growing source of liquid fuels that was historically excluded from conventional oil resource estimates and production forecasts. Tight oil also differs from conventional oil in both the geological characteristics of the resource and the methods of production.

The core issue for future supply is the extent and the rate of depletion of conventional oil, since this currently provides around 95% of global all-liquids supply. Options for mitigating this depletion include:

— substituting conventional oil with non-conventional oil;
— substituting all-oil with other non-conventional liquids (gas-to-liquids, coal-to-liquids and biofuels); and
— reducing demand for all-liquids (e.g. through improving end-use efficiency, substituting non-liquid energy carriers such as gas or electricity or reducing demand for the relevant energy services).

Both the extent and rate of depletion and the feasibility and cost of different mitigation options are the subject of intense debate.

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3. Oil production and resources

Conventional oil has traditionally been recovered through vertical oil wells, drilled through reservoirs from top to bottom. Since these typically contact only a few metres or tens of metres of the reservoir, large reservoirs require multiple wells. Today many wells commence vertically but are then deviated to follow the reservoir. Modern methods allow the drilling of several thousand metres of horizontal sections, thereby increasing access to the edges of the reservoir and achieving higher recovery with fewer wells.

After drilling, oil initially flows to the surface under its own pressure (*primary recovery*), but this is usually supplemented by pumping and by injecting water or gases into the field to maintain the pressure (*secondary recovery*). Falling pressure reduces the flow rate and may also permit gas to exsolve from the oil. On average around 35% of the *original oil in place* can be recovered by these methods [5–7]. Wells become uneconomic when the oil flow rate becomes too low, particularly when large volumes of water from secondary recovery are co-produced. In later life, many oil wells produce far more water than oil.

The *recovery factor* may be increased through the use of various *enhanced oil recovery* (*EOR*) techniques, such as steam injection, CO_2 injection and chemical flooding. These aim to reduce oil viscosity, to block the competing flow of gas or water and/or to drive oil towards the wells. The feasibility of different EOR techniques varies widely from one field to another and they currently account for less than 3% of global production. EOR typically raises recovery factors by 5–15%, but in rare cases total field recovery factors of over 70% can be achieved.

Recovery of tight oil is achieved through a combination of horizontal drilling and hydraulic fracturing ('fracking') of relatively impermeable rocks to release oil and gas at economic rates. Recovery of extra-heavy oil can be achieved through a variety of methods, but most commonly by steam injection followed by upgrading and/or dilution for transport by pipeline. Current recovery of oil sands is primarily through open-cast mining, but *in situ* methods using steam injection are being developed to access much larger deposits at greater depths and with lower environmental impacts. The recovery and conversion of kerogen oil is extremely energy intensive and is little practised on a commercial scale.

(a) Oil production

Global production of all-liquids averaged 85.7 million barrels per day (mb per day) in 2011, or 31.2 billion barrels per year (Gb per year). Global cumulative production amounted to approximately 1248 Gb, with half of this occurring since 1988 (figure 3). Crude oil and condensate[5] accounted for 80.0% of all-liquids production in 2011, with the remainder deriving from NGLs (14.1%) and non-conventional liquids (5.9%) (figure 4). Crude oil production grew at approximately 1.5% per year between 1995 and 2005, but then plateaued with more recent increases in liquids supply largely deriving from NGLs, oil sands and tight oil. These trends are expected to continue—for example, the International Energy Agency (IEA) [8] projects NGLs accounting for 19% of global all-liquids production by 2035, and unconventional oil 13.6% (figure 15). On a *per capita* basis, annual all-oil production peaked at 5.5 barrels in 1979 and has remained around 4.5 barrels since the mid-1980s. Annual consumption averages approximately 2.5 barrels per person in non-Organization for Economic Co-operation and Development (OECD) countries (82% of the global population) and approximately 14 barrels per person in the OECD, with the USA an outlier at 25 barrels per person.

Crude oil production is heavily concentrated in a small number of countries and a small number of giant fields, with approximately 100 fields producing one half of global supply,

[5]For brevity, the phrase 'crude oil' will be used in place of 'crude oil and condensate' in the remainder of this paper. This is because most data sources do not allow the produced volumes of these two liquids to be distinguished.

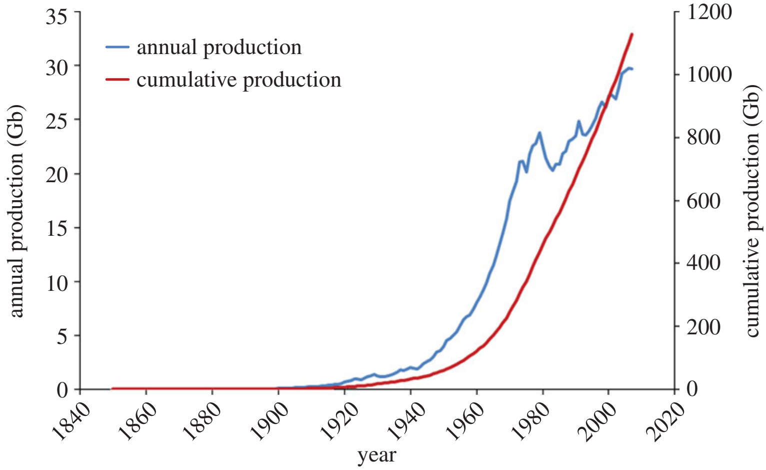

Figure 3. Global trends in all-oil production. Source: IHS Energy. Includes crude oil, condensate, NGLs, tight oil, heavy oil and syncrude from oil sands. (Online version in colour.)

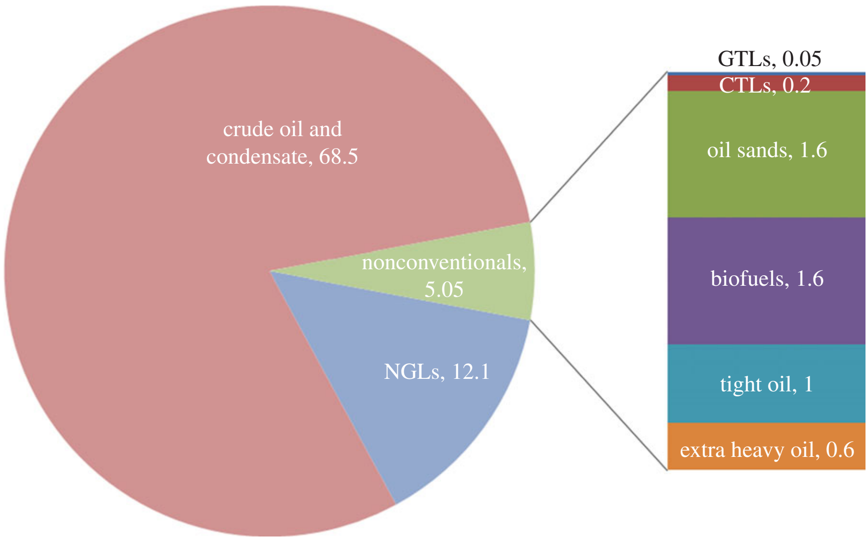

Figure 4. Breakdown of global all-liquids production in 2011 (mb per day). Source: IEA [8]. (Online version in colour.)

25 producing one quarter and a single field (Ghawar in Saudi Arabia) producing approximately 7% [5]. Most of these giant fields are relatively old, many are well past their peak of production [9], most of the rest seem likely to enter decline within the next decade or so and few new giant fields are expected to be found [4]. Future global production is therefore heavily dependent on the future prospects of the giant fields, but this remains uncertain—in part because the required field-level data are either unavailable or unreliable [4].[6]

(b) Oil reserves

The volumes of oil underground are variously described as reserves or resources depending upon how probable it is that these volumes will be produced over a given time frame with existing technologies. These volumes can be very different and must be clearly defined.

[6]Some field-level data are published annually by oil industry journals. More comprehensive data may be purchased (at considerable cost) from commercial sources, but there are questions over the reliability of some of these data, only a portion of which is audited.

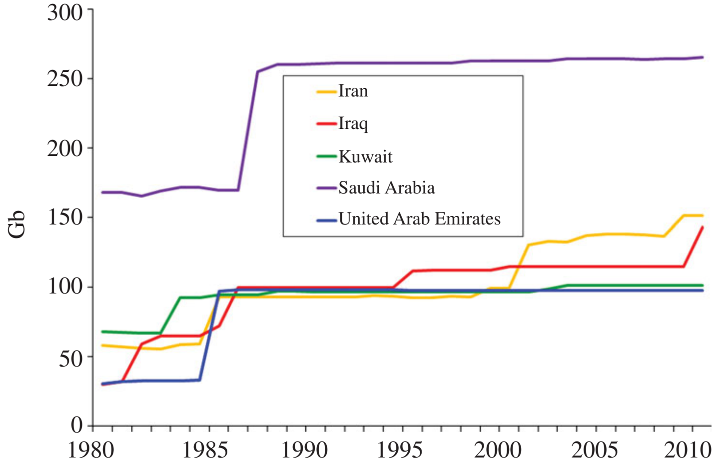

Figure 5. Annual proved reserves estimates for five Middle East states (1980–2011). Source: BP [13]. Saudi Arabia produced 100 Gb and the United Arab Emirates 27 Gb during this period. (Online version in colour.)

Oil reserves are those quantities of oil in known fields which are considered to be technically possible and economically feasible to extract under defined conditions. Reserve estimates rely upon uncertain assumptions about geology, technology and economics and are best expressed as a probability distribution. Point estimates may be quoted to three levels of confidence, namely *proved* (1P), *proved and probable* (2P) and *proved, probable and possible* (3P). While definitions vary, these are often considered equivalent to the probabilistic definitions P90, P50 and P10 which express the percentage probability that at least this quantity will be recovered [10]. Most data sources report proved reserves but these provide a highly conservative estimate of future recovery, especially at the regional level [11].[7]

Only a subset of global reserves is subject to formal reporting requirements and this is largely confined to the reporting of proved reserves for aggregate regions. Such data are notoriously unreliable, with many countries reporting unchanged reserves for decades (figure 5).[8] Proved and probable (2P) estimates should provide a more accurate guide to future recovery, as well as posing fewer problems with aggregation, but these estimates are more difficult to obtain and are not necessarily more reliable.

Globally, BP [13] estimates 1263 Gb of conventional proved reserves in 2011 (slightly more than cumulative production to date) and 389 Gb of non-conventional proved reserves. The latter comprise 169 Gb of Canadian oil sands and 220 Gb of Venezuelan extra-heavy oil, but both estimates are disputed and only a fraction of this volume is likely to be recovered over the next 25 years. In principle, global 2P reserves should be larger than 1P reserves, but according to an authoritative industry source (IHS Energy) global 2P reserves are approximately the same as national declared 1P reserves—suggesting an overstatement of proved reserves by several producing countries. Global proved reserves are rising, together with the global proved reserve to production (R/P) ratio (figure 6), suggesting to some that there is little risk of near-term supply constraints [15]. But proved reserves provide a misleading basis with which to measure depletion or forecast future production rates [16] and similar trends in R/P ratios have been observed in regions such as the UK where production has peaked and then declined [11].

[7]Regional reserve estimates are commonly derived by summing the estimates of individual fields, but such aggregation is only appropriate for mean estimates of recoverable resources and will lead to significant underestimation when applied to 1P (P90) estimates [11,12]. Aggregation of 2P (P50) estimates should lead to smaller errors, but the sign and magnitude of these will depend upon the shape of the underlying probability distribution.

[8]For example, the *Oil and Gas Journal* [14] reports identical reserves estimates for 2010 and 2011 from 69 of 101 oil-producing countries.

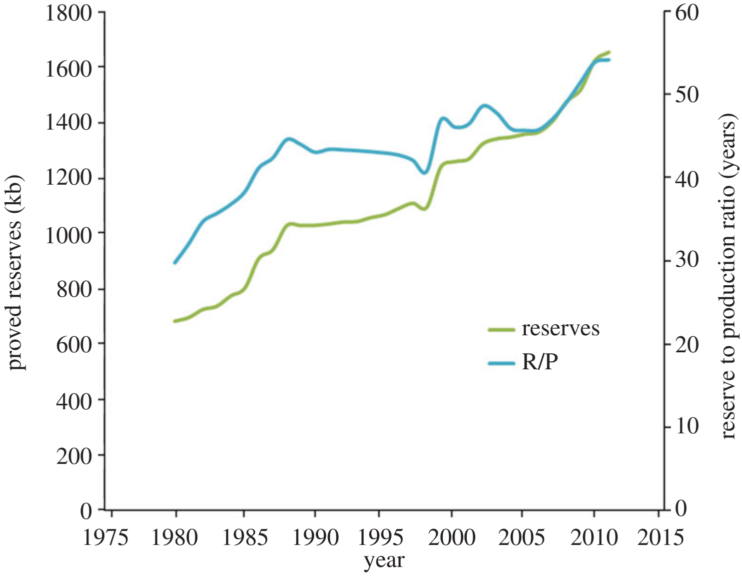

Figure 6. Global trends in all-oil proved reserves and the proved reserve to annual production ratio. Source: BP [13]. (Online version in colour.)

(c) Oil discoveries

The sum of cumulative production and reserves is commonly referred to as *cumulative discoveries*. At end 2011, both BP [13] and IHS Energy estimated global cumulative discoveries of conventional oil to be around 2486 Gb, although their reserve definitions and coverage of liquids do not coincide. Regional cumulative discovery estimates are changed by the discovery of new fields and by revisions to the reserve estimates for existing fields. The latter is commonly referred to as *reserve growth*, although cumulative discovery growth is a more accurate term, because high production rates may still cause the remaining reserves to fall year by year. Sources of reserve growth include better geological understanding, improved extraction technology, variations in economic conditions and changes in reporting practices.

The term *discoveries* may mean the resources contained in fields that are newly discovered within a particular time period or the change in cumulative discoveries from one period to the next. These are not necessarily the same, since reserve growth at existing fields contributes to 'discoveries' under the second definition even if no new fields are found. Some data sources (e.g. BP) record this reserve growth in the year in which the adjustments are made, while others (e.g. IHS) *backdate* the revisions to the year in which the relevant fields were discovered. Figure 7 (which uses backdated data) suggests that global new-field discoveries peaked in the 1960s and have fallen steadily since, although with an upturn around the turn of the century. Despite continuing improvements in exploration technology, most of the giant fields were discovered decades ago with more recent discoveries being smaller and more challenging to find and produce.

Figure 8 suggests that annual production has exceeded annual discoveries since 1980, but this conclusion neglects the contribution of reserve growth. The latter is hidden in figure 8 since the data source (IHS) backdates reserve revisions to the date of field discovery. When revisions are not backdated, annual reserve additions (i.e. the sum of newly discovered fields and reserve growth at existing fields) are found to *exceed* annual production, leading to an upward trend in global reserves (figure 6) [13,18]. Using industry 2P data, we estimate that approximately 48 Gb was added to global reserves each year between 2000 and 2007, split between approximately 15 Gb per year of new discoveries and approximately 33 Gb per year of reserve growth [11]. Reserve growth is therefore of considerable importance, but as production shifts towards newer, smaller

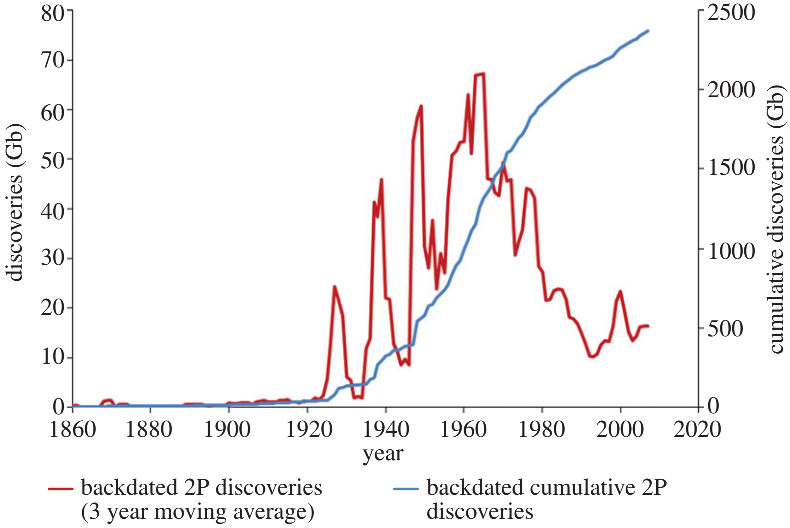

Figure 7. Global trends in backdated discoveries and cumulative discoveries. Source: IHS Energy. Includes crude oil, condensate, NGL, liquefied petroleum gas, heavy oil and syncrude. Based upon backdated 2P reserve estimates. (Online version in colour.)

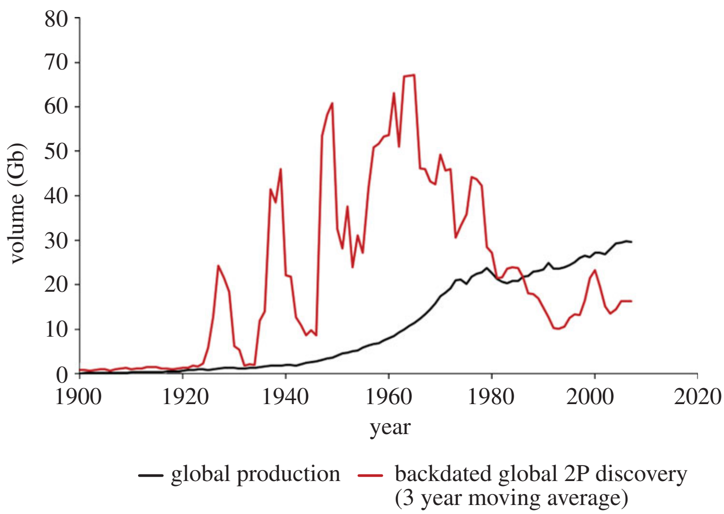

Figure 8. Global trends in production and backdated discoveries. Source: IHS Energy. Includes crude oil, condensate, NGLs, heavy oil and syncrude from oil sands. Discoveries based upon backdated 2P reserve estimates. While discoveries have fallen over time, the graph is potentially misleading since the discoveries for different years have not been estimated on a consistent basis. For example, the estimates for 1957 include 50 years of reserve growth, while the estimates for 2006 include only one year. This helps explain why comparable graphs published at different times have slightly different 'heights' and shapes for the backdated discovery data [17]. (Online version in colour.)

and offshore fields the rate of reserve growth is expected to decrease in both percentage and absolute terms [19–21].

(d) Oil resources

The *oil resource* may refer to all the oil in an area, regardless of whether or not it is dispersed or accumulated, discovered or undiscovered, technically recoverable or economic to produce.

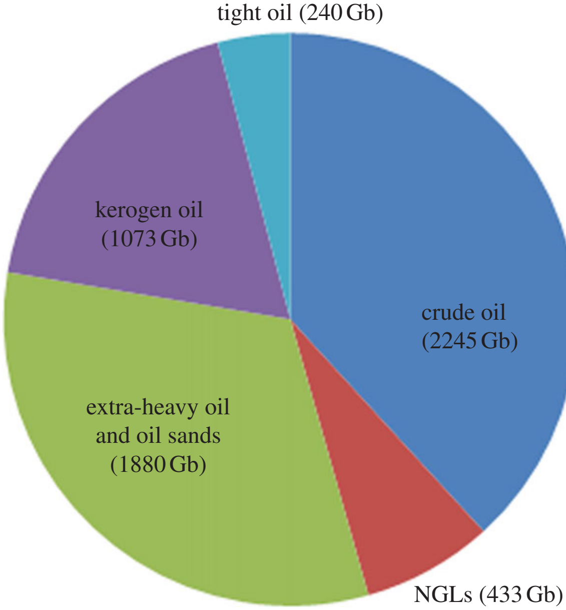

Figure 9. IEA estimate of the remaining technically recoverable resource of all-oil. Source: IEA [8]. (Online version in colour.)

Confusingly, the term sometimes refers solely to potentially recoverable oil. Estimates may be made of the *technically recoverable resource* (*TRR*) and/or the *economically recoverable resource* (*ERR*), but the range of uncertainty is usually very wide and these terms are often used interchangeably. The term *ultimately recoverable resource* (*URR*) refers to the oil that is estimated to be recoverable from a field or region over all time—from when production begins to when it finally ends.[9]

For conventional oil, the regional URR represents the sum of cumulative production, declared reserves, the anticipated reserve growth at known fields and the resources estimated to be recoverable from undiscovered fields—commonly termed the *yet-to-find* (*YTF*). The latter term is less appropriate for tight oil and oil sands, since these are located in continuous formations rather than discrete fields. However, extensive drilling is required to establish the spatial boundaries, geological characteristics and recoverable resources of these formations, and the productivity of individual wells varies widely both within and between such formations [22–25].

Estimates of the global URR for conventional oil fall within the range 2000–4300 Gb, compared to cumulative production of 1248 Gb through to 2011 [11]. The IEA's [8] most recent estimate is 3926 Gb which is higher than earlier estimates and reflects recent reassessments of the non-US YTF (731 Gb)[10] and future reserve growth (681 Gb) [27,28]. Estimates of the URR of all-oil are much larger (e.g. 7119 Gb from the IEA [8]) and suggest that only one-sixth of the total recoverable resources has been produced (figure 9). However, the confidence intervals for such estimates are very wide [11,27–29].

In interpreting these numbers, it is essential to recognize that large *quantities* of resources within the Earth's crust provide no guarantee that these can be produced at particular *rates* and/or at reasonable cost. There are huge variations both within and between resource types in terms of size of accumulation, depth, accessibility, chemical composition, energy content, extraction cost, net energy yield (i.e. the energy obtained from the resource minus the energy required to find, extract and process it), local and global environmental impacts and, most importantly, the feasible

[9]In principle, this includes oil that is currently undiscovered, not recoverable with existing technology and/or not currently economic, but which is expected to become so before production ceases.

[10]This estimate includes resources that are unlikely to be recoverable within the next 25 years, such as 74 Gb in the Arctic and FSU, but also excludes a number of smaller, less accessible regions that may potentially contain oil [26].

rate of extraction—to say nothing of the geopolitics of access. Higher quality resources tend to be found and developed first, and as production shifts down the ‘resource pyramid’, increasing reliance must be placed upon less accessible, poorer quality and more expensive resources that have a progressively lower net energy yield and are increasingly difficult to produce at high rates. Compare, for example, the monetary and energy investment required to produce 100 kb per day from the giant oil fields of the Middle East to that required to achieve comparable rates of production from deep-water oil fields, subarctic resources or the Canadian oil sands. To quote a widely used phrase in this context, it is not so much the size of the *tank* that matters but the size of the *tap*.

This is not simply an issue of the steeply rising production costs of poorer quality resources because technical and net energy constraints may make some resources inaccessible and some production rates unachievable regardless of cost. Kerogen oil is especially constrained in rate and net energy terms and may never become economic to produce, yet it accounts for 19% of the IEA estimate of remaining recoverable resources (figure 9). Hence, a critical evaluation of future supply prospects must go beyond appraisals of aggregate resource size and examine the technical, economic and political feasibility of accessing different resources at different rates over different periods of time.

4. Oil ‘peaking’

The production of conventional oil must eventually decline to almost zero, because it is a finite resource. The phenomenon of ‘peak oil’ derives from basic physical features of the oil resource that constrain the ‘shape’ of the production cycle from an oil-producing region (i.e. the rate of production over time) and typically lead production to rise to a peak and then decline. But these physical features are mediated by multiple technical, economic and political factors that create a range of possibilities for the shape of the production cycle for a region and considerable uncertainty about the timing of any future peaks in production. The relative importance of these ‘below-ground’ and ‘above-ground’ factors varies between regions and over time and has become a central focus of dispute.

(a) Well and field peaking

As an oil well is brought online, its rate of production rises rapidly to a peak which may be extended into a plateau by restricting the flow rate or injecting fluids to maintain reservoir pressure. But at some point, production begins to decline as a result of falling pressure and/or the breakthrough of gas or water (figure 9). In mature wells, the ‘water-cut’ may represent 90% or more of the volume of produced liquids, creating a challenge for disposal. Production profiles of individual fields tend to be similar, with larger fields having longer plateaus achieved in part by drilling new wells.

Post-plateau, the production from individual wells and fields typically declines at a constant rate (exponential decline) or at a falling rate (hyperbolic decline). Empirical equations to model this production decline are widely used to forecast future well or field production and to estimate ultimate recovery [9,30,31]. In practice, the shape of the production cycle is often modified by production interruptions, the introduction of new technology and other factors.

For most oil fields, the decline period accounts for the majority of the production cycle and the bulk of cumulative production. As an illustration, figure 10 shows how each of the UK’s largest offshore fields (Forties, Brent and Ninian) took 3–8 years to reach peak, stayed on a plateau for 2–3 years and then entered a prolonged and approximately exponential decline. Forties produced 29% of its cumulative production to date before peak, Ninian 30% and Brent 40%. From a sample of 77 post-peak UK fields, we estimate an average decline rate of approximately 12.5% per year, and an average of 40% of cumulative production before peak—a number that will fall with time because the fields are still producing [4].

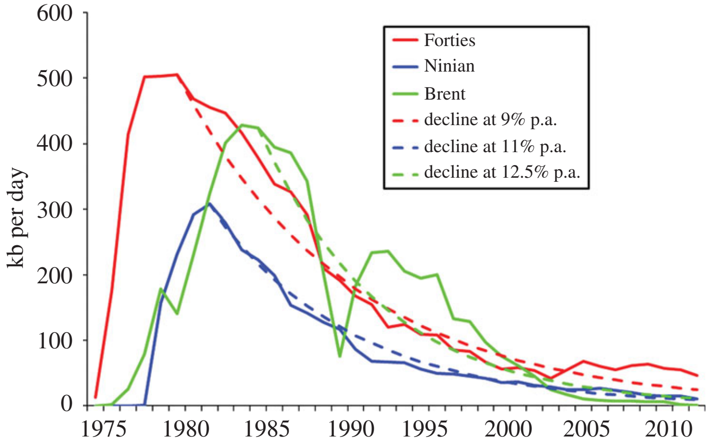

Figure 10. Production profiles for three UK North Sea oil fields, with indicative exponential decline curves. Source: UK Department of Energy and Climate Change. (Online version in colour.)

To maintain or increase regional production, the declining production from post-peak fields needs to be replaced by increased production from new fields.[11] Hence, the average rate of decline from post-peak fields is a critical determinant of regional and global investment needs and future oil supply. Recent studies of globally representative samples of post-peak crude oil fields find a production-weighted average decline rate of at least 6.5% per year [5,32,33]. This is lower than the average decline rate, since larger fields tend to decline more slowly [4,32–37]. Decline rates appear particularly low for the supergiant fields of the Middle East, but this is partly a consequence of quota restrictions of the Organization of the Petroleum Exporting Countries and disruptions from political conflict. The same studies also demonstrate that offshore fields decline faster than onshore fields and that newer fields decline faster than older fields [4]. If smaller, younger and offshore fields account for an increasing share of future global production, the average decline rate for conventional oil fields will increase prior to the peak [5].[12] Greater reliance upon tight oil resources produced using hydraulic fracturing will exacerbate any rising trend in global average decline rates, since these wells have no plateau and decline extremely fast—for example, by 90% or more in the first 5 years (figure 11) [24]. The implications of this for global production are explored further below.

(b) Regional peaking

A *petroleum basin* is a geologically defined region containing several fields, such as the North Sea. The shape of the basin production cycle depends upon the size distribution of the component fields, the order in which they are discovered and produced and the production cycle of each. Most oil resources in a basin tend to be located in a small number of large fields, with the balance being located in a much larger number of small fields [4,39–41].[13] The large fields tend to be discovered relatively early, in part because they occupy a larger area, with subsequent discoveries tending to be progressively smaller and requiring more effort to locate [11].

[11]Historically, EOR has only briefly been able to reverse the decline of any post-peak conventional field, and we see no reason for this behaviour to change. The effects of EOR are already included in contemporary estimates of the average rate of production decline from different groups of fields.

[12]In the long term, when global conventional production is past peak and the rate and size of discovery are falling, the old giant fields may increasingly dominate total production. If this occurs, the long term aggregate decline rate would converge towards the average decline rate of the giant fields [38].

[13]There is a long-standing debate about whether oil fields typically follow a lognormal or power-law size distribution [4]. But the uncertainties largely relate to the 'tail' of the distribution and do not affect this general conclusion.

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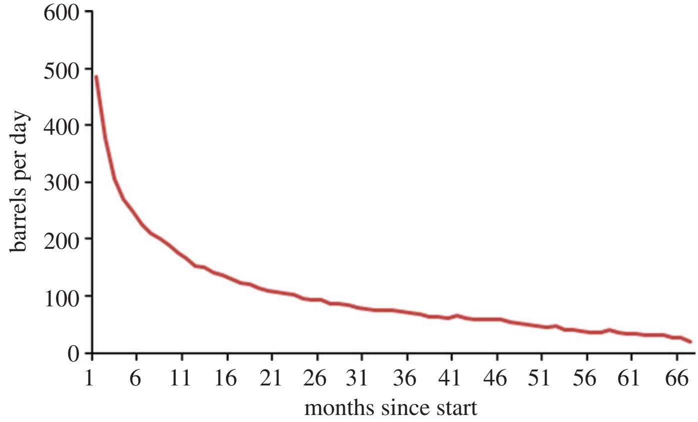


Figure 11. Mean decline curve of tight oil wells in the Bakken play in North America. Source: Hughes [24]. Compiled from 66 months of production data from Bakken wells up to May 2012. The total number of wells climbed from approximately 20 in 2004 to 4598 in May 2012. The mean first year decline is 69% and the overall decline over five years is 94%. (Online version in colour.)

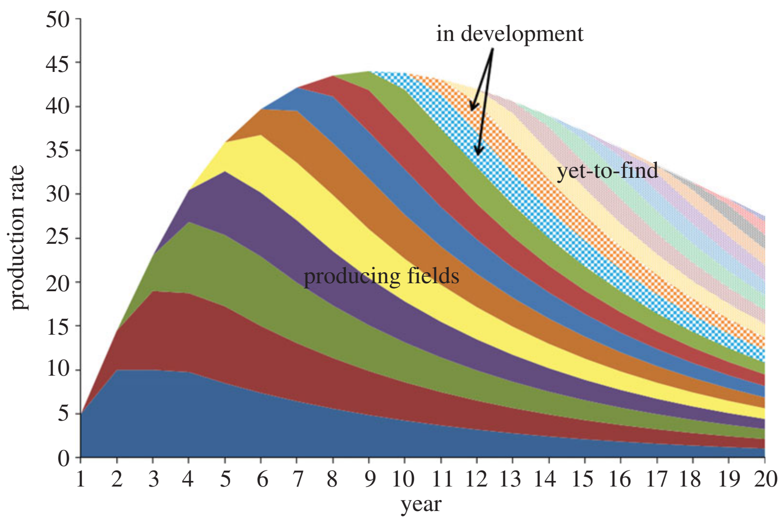


Figure 12. Simple model of the production cycle of a basin. Assume that (i) one field is brought on-stream each year in declining order of size; (ii) each field is 10% smaller than the previous field; (iii) fields take two years to reach peak, which is sustained for two years; (iv) peak production is 10% of URR annually; and (v) annual post-peak production is 13% of remaining resources, yielding a production decline rate of 13% per year. Source: based on Bentley *et al*. [42]. (Online version in colour.)

Despite varying political and economic influences on resource development, this broad pattern usually applies and has important implications that can be illustrated with the help of a simple model (figure 12). Here, it is assumed that one field is brought into production every year and each field is 10% smaller than its predecessor. In this example, the regional peak of production (in year nine) occurs when the additional production from the small fields that were developed relatively late becomes insufficient to compensate for the decline in production from the large fields that were developed relatively early. At this point, approximately one-third of the recoverable resources of the basin have been produced, half are contained in the reserves of producing and discovered fields, and one-fifth remain to be discovered.

Models such as this are robust to a variety of assumptions about the size distribution, discovery sequence and production cycle of individual fields, *provided* it is assumed that the larger fields are found and developed relatively early [43]. Such models suggest that production from the

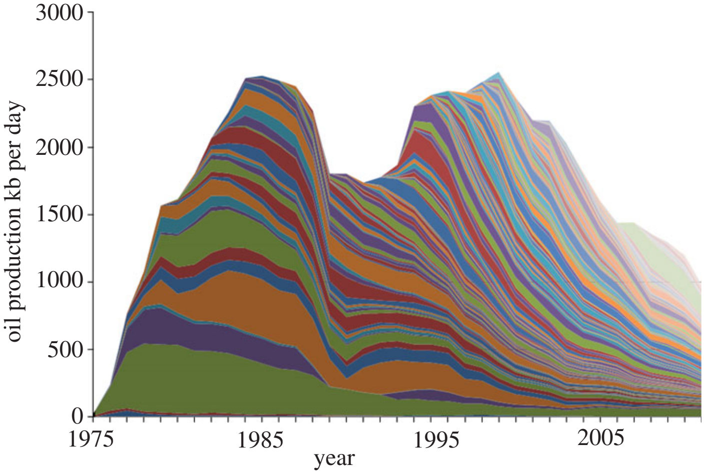


Figure 13. UK offshore oil production by field, 1975–2011. Source: data from UK Department of Energy and Climate Change. (Online version in colour.)

basin will begin to decline when less than half of the regional URR has been produced, leading to an aggregate production cycle that is asymmetric to the left [11]. This is strongly supported by empirical evidence from the growing number of oil-producing regions that have passed their peak of production. For example, Brandt [44] analysed 74 post-peak regions and found that the rate of production increase exceeded the rate of decline in over 90% of cases. Similarly we analysed 37 post-peak countries and found an average of only 24% of the estimated URR had been produced at the onset of decline.[14]

The UK North Sea (figure 13) provides an excellent example of this process and is one of few where the relevant data are in the public domain. The first peak preceded the Piper Alpha disaster of 1988, which led to extensive remedial engineering and lower production in many fields, but the second was driven by the mechanisms described above. It may not be a coincidence that this peak occurred in 1999 when oil prices and exploratory drilling were at a 30-year low, but the small size of subsequent discoveries suggests that the peak could not have been significantly delayed—and in the absence of Piper Alpha may have occurred earlier.

Oil-producing countries incorporate partial, single or multiple basins that are not necessarily developed in decreasing order of size. Nevertheless, country or regional production cycles are usually similar to those of individual basins. Figure 14 shows the aggregate production profile for the USA, broken down by region and oil type. The 1970 peak in Lower 48 production (9.6 mb per day) was anticipated by Hubbert [46] and largely driven by the declining size of newly discovered fields although state restrictions on production influenced the timing [47]. New plays in Alaska and the deep-water Gulf of Mexico temporarily increased aggregate US oil production in the late 1970s and mid-1980s, and the development of tight oil resources has done the same since 2008.

The production cycle for tight oil resources is driven by a slightly different set of mechanisms since this resource is located in continuous formations rather than discrete fields. Nevertheless, the outcome is similar to that for conventional oil. With exceptionally high decline rates for individual wells (figure 11) regional tight oil production can only be maintained through the continuous drilling of closely spaced wells.[15] But tight oil plays are heterogeneous, with much

[14]Using US Geological Survey [45] estimates of the regional URR, we estimated a simple mean for 'depletion at peak' of 22%, a production-weighted mean of 24% and a maximum of 52%. URR estimates tend to increase over time as knowledge expands, prices increase and technology improves, so estimates of the level of depletion at peak are likely to fall.

[15]The largest tight oil play in the USA is the Bakken in North Dakota. In May 2012, this was producing 0.57 mb per day from 4598 wells. Production was on a rising trend, sustained by drilling approximately 1500 wells each year. The US Energy Information Administration (EIA) estimates that there are only approximately 11 700 available drilling locations in the Bakken, although industry estimates are higher [24].

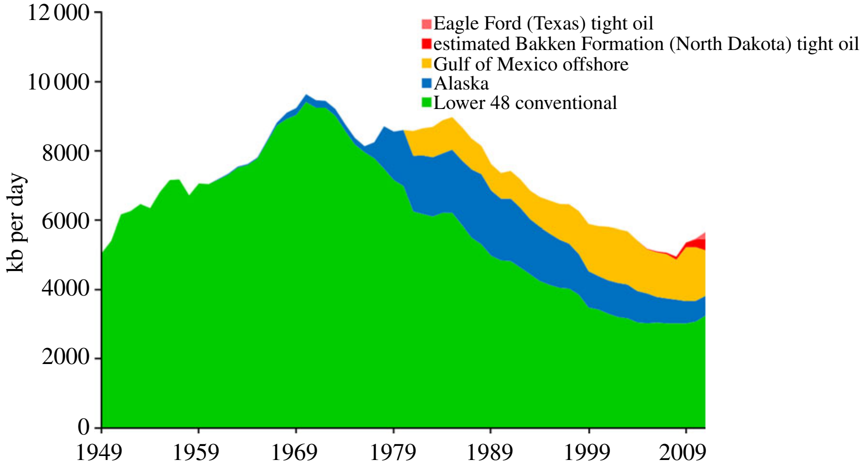


Figure 14. US crude oil production by region and type, 1949–2011. Source: US Energy Information Administration (http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0501b; http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm); North Dakota Department of Mineral Resources (http://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp); Texas Railroad Commission (http://www.rrc.state.tx.us/eagleford/index.php#stats). Bakken Formation tight oil production estimated by subtracting extrapolated conventional oil production from total production. (Online version in colour.)

higher well productivity in the 'sweet spots' than elsewhere [22–24,48]. So when the sweet spots become exhausted, it becomes increasingly difficult to maintain regional production. Based upon these considerations, Hughes [24] suggests that aggregate US tight oil production is likely to peak around 2.5 mb per day (compared to total US oil production of 6.9 mb per day in 2008) and is likely to decline very rapidly after 2017.[16] Other, less detailed studies are more optimistic: for example, the IEA projects a peak of 3.2 mb per day in 2025, followed by a slower decline.

5. Oil futures

(a) Anticipating the global peak

The same mechanisms that lead to peaks and declines in regional oil production should ultimately lead to a peak and decline in global production. This inevitability was first pointed out by Hubbert in the mid-1950s, but the multiple forecasts of regional and global peaks that have been made since that date have frequently proved premature [49]. More optimistic forecasts have often proved equally incorrect, but it takes longer for their errors to become evident [50,51].

The available methods for forecasting future oil supply vary widely in their theoretical basis, inclusion of different variables, level of aggregation and complexity [11,52]. Each approach has strengths and weaknesses and none can yet provide generally accepted estimates (box 2).

But despite multiple uncertainties, the timing of the global peak in *conventional* oil production appears relatively insensitive to both the size of recoverable resources and the shape of the production cycle [11,61]. Simple calculations suggest that delaying a global peak in conventional oil production beyond 2030 would require more than 1700 Gb of remaining recoverable resources (i.e. a URR > 3000 Gb), together with a relatively slow increase in production prior to the peak

[16]Hughes' [24] analysis is based upon the production history of 65 000 wells from 31 shale plays, contained in the DI Desktop/HDPI database, together with EIA data on the number of available drilling locations within each play. Assuming current drilling rates are maintained, Hughes projects a peak in US tight oil production of 2.3 mb per day in 2016, declining rapidly to 0.7 mb per day in 2025.

Box 2. Methods of forecasting oil supply.

Hubbert's method involved fitting curves to historical trends in regional production and discovery and extrapolating these forward in time, constrained by assumptions about the size of recoverable resources. This 'curve-fitting' approach is straightforward and widely used, but lacks an adequate theoretical basis, relies upon uncertain assumptions about the regional URR, is sensitive to the choice of functional form and neglects important economic and political variables [53]. The latter may be more easily accommodated with econometric techniques [54,55], but while these provide a better match to historical data this may not translate to more accurate forecasts of future production. Hybrids of curve-fitting and econometrics offer promise, but can also have the disadvantages of both [56,57]. Systems dynamic models [58,59] reproduce the physical and economic mechanisms that govern oil production, but can also be overcomplicated and unstable and frequently lack both empirical validation and sufficient data for parametrization. Perhaps the most promising approach is to model the production of individual fields and projects and to construct regional forecasts by aggregating this bottom-up information [60]. However, existing bottom-up models are hampered by their reliance on proprietary datasets, lack of transparency, uncertainty over key variables and the need to make multiple assumptions [52]. Given the potential for political, economic, or technological disruptions, no model can provide estimates of great precision. Moreover, increasing model complexity does little to address this problem and is subject to rapidly diminishing returns.

and a relatively rapid decline thereafter, especially if the peak is extended into a multi-year plateau [11].

Following an earlier literature review, we concluded that a sustained decline in global conventional production appears probable before 2030 and there is significant risk of this beginning before 2020 [11,62]. This assessment excluded tight oil resources since these were classified as unconventional. However, on current evidence the inclusion of tight oil resources appears unlikely to significantly affect this conclusion, partly because the resource base appears relatively modest (figure 9). Despite rising proved reserves, the depletion of conventional oil resources is relatively advanced with cumulative production equal to at least 30% of the global URR (i.e. close to the point at which production has typically been found to decline in a region). A significant portion of this resource is located in small fields in difficult locations that are unlikely to be accessed quickly. However, global supply is profoundly influenced by geopolitical factors and any supply constraints are likely to trigger much greater price increases and demand/substitution responses than would be the case at the regional level—a process that is already underway. As a consequence, a sharp peak in global conventional oil production appears unlikely.

To maintain or increase global liquids supply, any decline in production from post-peak fields needs to be replaced by investment in EOR at those fields (at much greater than historic investment rates, the effects of which contribute to the current global post-peak decline rate), the discovery and development of new fields or increased production of other liquid fuels. Current evidence on average field decline rates suggests that a minimum of 3 mb per day of new capacity must be brought on stream each year to compensate for declining crude oil production—equivalent to a new Saudi Arabia coming on stream every three years [4,8]. If demand grows and/or decline rates increase, significantly greater annual investment will be required.

Based upon these considerations, the IEA [8] anticipates crude oil production from existing fields falling from 68.5 mb per day in 2011 to only 26 mb per day in 2035 (figure 15). However, it expects total crude production to fall only slightly by that date (to 65.4 mb per day) as a result

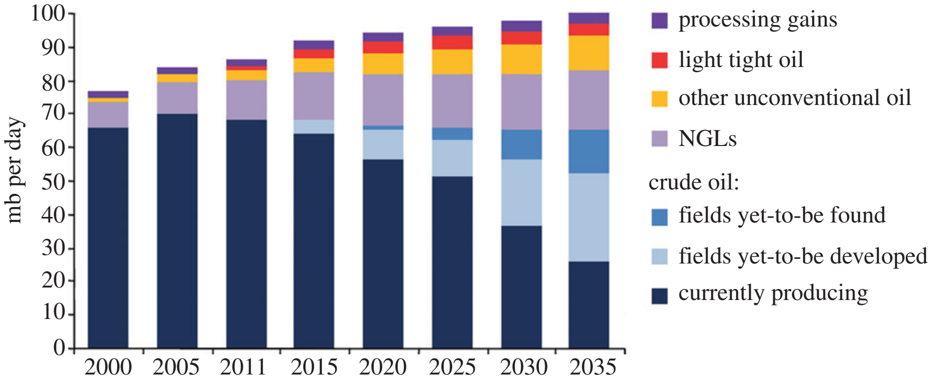


Figure 15. IEA projection of global all-liquids production to 2035. Source: IEA [8]. The 'New Policies' scenario takes into account policy commitments and plans that have already been implemented, as well as those that have been announced. (Online version in colour.)

of the rapid development of 'fallow'[17] and undiscovered crude oil fields. Moreover, it anticipates global all-liquids production increasing to 96.8 mb per day over that period as a result of rapid growth in NGL production and the development of tight oil, oil sands and other unconventional resources. In other words, while the IEA now suggests that global *crude oil* production is past its peak, it does not anticipate a significant decline before 2035 and it foresees no peak in *conventional*, *all-oil* or *all-liquids* production before that date.

Despite the projected global liquids supply up to 2035 being significantly lower than in earlier IEA publications, these projections remain the target of criticism. For example, Höök *et al.* [37] argue that production from existing fields could decline more quickly than the IEA assumes, while Aleklett *et al.* [63] argue that the projections rely upon implausible assumptions about the rate at which fallow and undiscovered fields can be developed and produced.[18] Both studies imply more rapid decline of global crude oil production and hence more difficulty in maintaining aggregate global liquids supply. Furthermore, the IEA projection assumes adequate investment, no geopolitical interruptions and prices that do not significantly constrain global economic growth.

(b) Substitution and demand reduction

Given the multiple uncertainties involved, disputes over the precise timing of a global peak in conventional oil production are unhelpful. What is more relevant is the appropriate response to the risk of rising prices and supply constraints and the extent to which markets can be relied upon to mitigate those risks. Mitigation can be achieved through fuel substitution and demand reduction but both will prove challenging owing to the scale of investment required and the associated lead times. For example, a 2008 report for the US Department of Energy [64] argued that large-scale mitigation programmes need to be initiated at least 20 years before a global peak if serious shortfalls in liquid fuels supply are to be avoided. While this report overlooked key options such as electric vehicles and tight oil, it also assumed a relatively modest rate of post-peak crude oil decline (2% per year)[19] and ignored the environmental consequences of expanding

[17]Fallow fields are fields that are discovered but not currently scheduled for development.

[18]Aleklett *et al.* estimate historical depletion rates for different regions, defined as the ratio of annual production to remaining recoverable resources, together with the depletion rates assumed by the IEA for fallow and undiscovered fields. This leads them to conclude that the depletion rates assumed by the IEA are implausibly large. But their comparison of regional depletion rates with the corresponding rates for specific groups of fields is potentially flawed.

[19]To frame this, a 2% decline in crude oil production implies the loss of 1.4 mb per day in the first year. On an energy equivalent basis, this corresponds to the output of ninety 1 GW nuclear power stations, or approximately one quarter of global nuclear capacity.

the supply of non-conventional resources. Avoiding these would necessarily restrict the range of available options.

Many sources anticipate large-scale substitution of *NGLs* for crude production over the next two decades, owing to expanding gas supply (including shale gas) and/or increases in the average NGL content of that gas. While the IEA [5] states that the latter is expected to remain constant, its projections imply a doubling. But even assuming production grows as anticipated, NGLs cannot fully substitute for crude oil since they contain about a third less energy per unit volume and only about one-third of that volume can be blended into transport fuels.[20] NGLs can substitute for crude oil as a petrochemical feedstock and may partially compensate for increased heavy oil within the refinery input mix, but at some point a rising volume of NGLs will be unable to adequately make up for reduced crude supply.

The rapid and largely unexpected expansion of *tight oil* since 2007 provides a powerful demonstration of how technical change, incentivized by rising prices, can offset depletion. Heralded by some as a revolution [65], this resource is at an early stage of development and its future prospects remain highly uncertain. On current evidence, tight oil appears unlikely to offset the depletion of crude oil for an extended period of time, in part because the resource base appears relatively modest (figure 9). The IEA mean estimate of 240 Gb is comparable to McGlade's [66] (278 Gb)[21] and is only 10% of its estimate of conventional oil resources. Also, the very high decline rates make it challenging to sustain regional production, and the requirement for continuous drilling of closely spaced wells is likely to restrict development in densely populated areas. Nevertheless, the future potential of this resource is much debated and is a key area of uncertainty to resolve.

Oil sands already make an important contribution to global liquids supply and most forecasts anticipate a significant expansion over the next 20 years. But according to the Canadian Association of Petroleum Producers [68], the Canadian oil sands will deliver only 5 mb per day by 2030, which represents less than 6% of the IEA projection of all-liquids production by that date. Similarly, Söderbergh *et al.* [69] conclude that a 'crash programme' to develop the oil sands could only deliver a comparable amount. Also, this resource is significantly more energy- and carbon-intensive than conventional oil, and surface mining has massive impacts on local and regional environments.

GTLs and CTLs are already produced in small volumes as high cost alternatives to conventional oil and may be expected to expand their contribution in the future. But the environmental impacts of CTL production are severe and the inefficiencies of the process mean that significant quantities of coal and gas would be required to provide more than a marginal contribution to total liquids supply [70]. Taken together, these features are likely to greatly restrict their potential contribution.

Finally, *biofuels* offer promise as well as potentially lower environmental impacts, but expansion of production is constrained by the large land areas required[22] and the probable conflicts with food production. Commercially produced biofuels also have a lower net energy yield than conventional oil, implying the need for a 50–600% increase in primary energy inputs to produce an equivalent volume of transportation fuels [72]. While several studies suggest that 'second-generation' biofuels could provide up to a quarter of global transport fuel by 2050 [73],

[20]Natural gasoline (pentane and above), isobutane and butane are conventionally blended into gasoline, but ethane and propane are not.

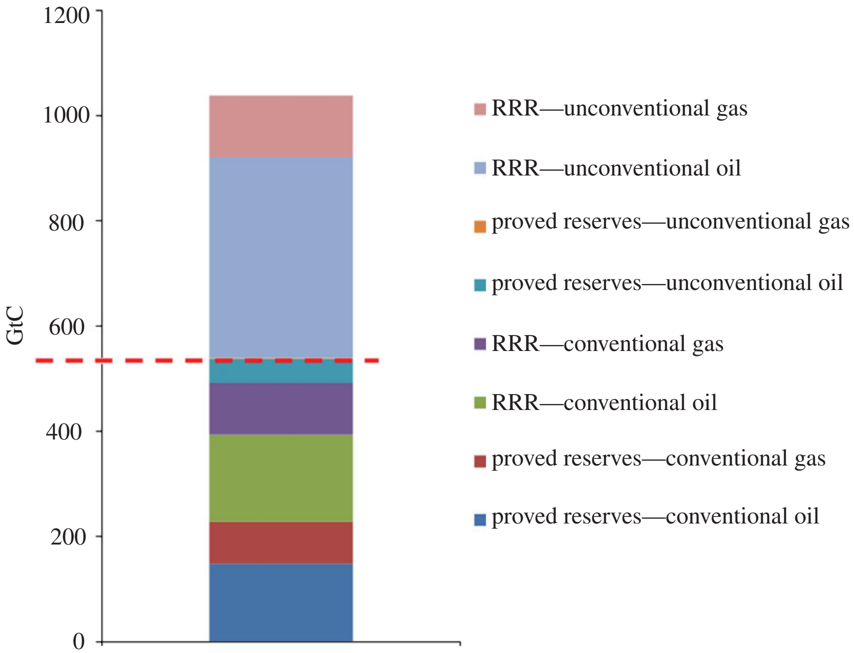
[21]Tight oil resources have not been systematically investigated on a global scale. McGlade [66] uses a relatively crude method based upon a review of shale gas resource estimates [67] and assumptions about the ratio of tight oil to shale gas within each region. This gives a range from 150 Gb to 508 Gb, with a central estimate of 278 Gb.

[22]For example, replacing US gasoline consumption with corn-based ethanol would require approximately two million km^2 of cropland, which is 15% larger than the total US farmland area. Moreover, this calculation neglects the primary energy required to produce, transport, process and deliver the ethanol which appears to be only slightly less than the energy obtained from using it [71]. Hence, corn-based ethanol production is heavily subsidized in energy (as well as monetary) terms, making large-scale substitution impractical over the longer term.

Box 3. Oil and gas resources and cumulative carbon emissions. Source: [8,13,66,67].

A growing body of evidence indicates that global temperature change is approximately linearly related to *cumulative* carbon dioxide emissions and largely independent of the pattern of emissions over time [78–82]. Several modelling studies suggest that the most probable cumulative emissions for an average global temperature increase of 2°C is around 1100 GtC, with a 5–95% uncertainty range of 1–2.5°C per 1000 GtC [80]. Given that humanity has already emitted some 550 GtC (to end 2011), a 50 : 50 chance of meeting the 2°C target is likely to require future cumulative emissions to remain below a similar value (approx. 550 GtC)—with a higher probability of meeting the target requiring lower emissions.

As the following figure indicates, such a threshold will be reached if the remaining recoverable resources (RRR) of conventional oil and gas are used, together with the proved reserves of oil sands and extra-heavy oil. Further exploitation of unconventional oil and gas resources would significantly reduce the probability of meeting the temperature target, unless those emissions can be captured and sequestered. However, this analysis *ignores* the emissions from coal combustion, which are currently 70% of those from oil and gas and are increasing more rapidly. As a result, the allowable 'budget' of oil and gas resources is much less than indicated here. Indeed, with a realistic allowance for future coal consumption, a 2°C target implies that only some of the *conventional* oil and gas resources can be used.



these projections are sensitive to key assumptions [74] and would require significant technological breakthroughs.

These judgements deserve much closer scrutiny and need to be re-evaluated as experience grows in producing these resources. Based upon current evidence [8,70,73,75–77], we estimate that around 11–15 mb per day of non-conventional liquids production could be achieved in the next 20 years at costs similar to or higher than today's 'marginal barrel' at approximately $90–120 per barrel (figure 16). This would justify the IEA projection (figure 15), but only if crude oil production remains on a plateau over that period and NGL production expands as anticipated. If crude oil production falls, then total liquids production seems likely to fall as well, leading to

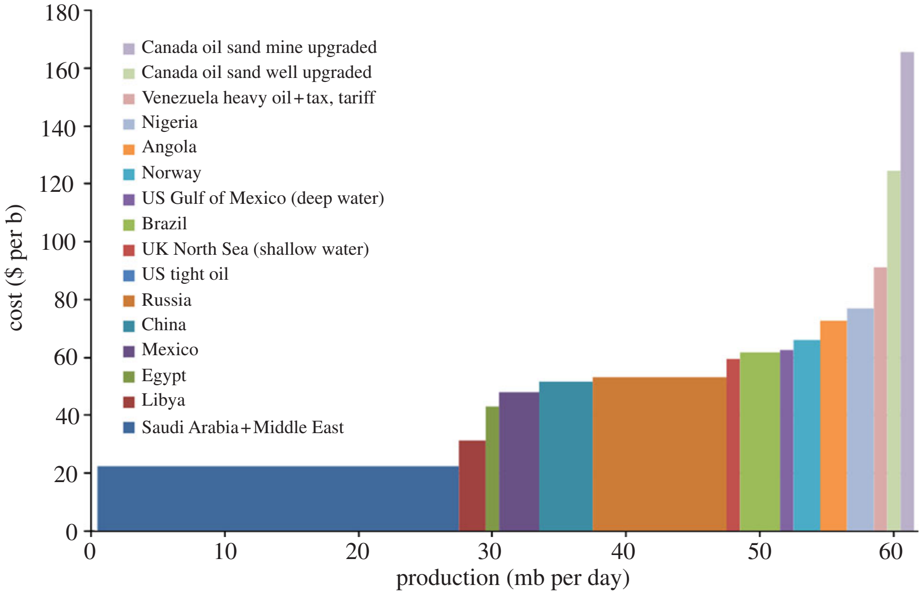


Figure 16. Estimated production cost of various oil resources. Source: IHS-CERA. Assumes 15% rate of return. Canadian oil sand production is relatively cheap at the mine mouth, but requires expensive upgrading before it can be transported by pipeline to refineries. Source: [8,13,66,67]. (Online version in colour.)

significant price increases and potentially serious impacts on the global economy. Also, figure 15 obscures the falling energy content per unit volume of global liquids supply, together with the falling net energy yield and growing carbon intensity. The last point is especially serious, since ambitious targets for reducing carbon emissions are likely to be inconsistent with expanding the supply of non-conventional liquids. As box 3 shows, avoiding dangerous climate change requires the bulk of these resources to remain in the ground.

The final and most promising mitigation option is to weaken the link between economic growth and liquid fuel *demand*. This will require major changes in the transport sector which accounts for half of global consumption and nearly two-thirds of OECD consumption. Passenger cars are responsible for approximately half of this, but substantial reductions can be achieved through improving vehicle efficiency, increasing average occupancy, accelerating the diffusion of alternative vehicle technologies, shifting to different transport modes or simply reducing the overall demand for mobility. Given the potential of all these alternatives [83] and the necessity to move rapidly towards low carbon transport systems, they deserve to be given the highest priority. Important changes in this direction are already underway, such as the recent halting of the long-term trend of increased passenger travel in OECD countries ('peak car') [84], and the multiple policy initiatives being introduced around the world. But the core issue is the *rate* at which this transition can be achieved and the extent to which it can offset the rapidly growing and potentially huge demand for car-based mobility in emerging economies and the developing world. For example, with over one hundred million cars, China is now the largest car market in the world, but *per capita* levels of car ownership remain comparable to that in the USA in 1920.

As Sager *et al.* [85] have shown, OECD levels of car-based mobility are unlikely to be sustainable for a global population of 9 billion, even assuming a rapid, global transition to battery-electric vehicles and very low carbon electricity systems. Hence, technical improvements will need to be accompanied by serious efforts to restrict the overall growth in mobility and to promote the most efficient modes. This conclusion applies even more strongly to shipping, road freight and aviation which currently account for 40% of transport energy use and which have comparatively few technical solutions available. We therefore expect the combination of oil depletion and environmental constraints to have far-reaching implications for these modes, along with the economic activities and social practices they enable. But most governments and electorates remain either unaware of these implications or reluctant to face up to them.

6. An overview of the Theme Issue

As the above discussion demonstrates, future oil supply is a complex and multifaceted topic, with multiple influencing variables and varying opportunities for mitigation. To improve understanding of these issues, the papers in this Theme Issue of *Philosophical Transactions A* seek to provide an up-to-date synthesis of the uncertainties and risks surrounding future global oil supply, as well as assessing the potential of several mitigation options. The papers include perspectives from both the natural and social sciences and reflect a range of views.

The first five papers examine a number of aspects of conventional oil depletion. In the first, *Sorrell & Speirs* [86] examine the use of curve-fitting techniques for estimating recoverable resources—an approach closely associated with the peak oil debate. They summarize the historical origins, contemporary application and strengths and weaknesses of nine different types of curve-fitting technique, and update and extend Hubbert's mathematical synthesis of those techniques [87,88]. Using illustrative data from a number of oil-producing regions, they demonstrate how different techniques, together with variations in the length of time series, functional form and number of curves, repeatedly lead to inconsistent results. They conclude that such techniques have a systematic tendency to underestimate recoverable resources and hence raise concerns about their use in forecasting future oil supply.

Höök et al. [89] summarize the current state of knowledge on the rate of decline of production from different types of crude oil fields (decline rates) and the rate at which remaining resources are being and can be produced (depletion rates). They clarify the definition of decline and depletion rates, identify their physical and economic determinants, explain their importance for regional and global oil supply and examine how these rates vary between different regions and types of field. They conclude that decline and depletion rates are generally higher for smaller fields and question the values that are assumed or implied for these variables within several global supply forecasts.

Murphy [90] examines the importance of the *energy return on investment* (EROI) for liquid fuels production and the implications of declining EROI for the global economy. From a review of the rather limited literature on this topic, Murphy concludes that: the EROI for global oil and gas production is roughly 15 and declining while that for the USA is 11 and declining; the EROI for unconventional oil and biofuels is generally less than 10; there is a negative exponential relationship between oil prices and aggregate EROI which may become nonlinear as the latter falls below 10; and the minimum oil price needed to increase oil supply is consistent with that which has historically triggered economic recessions. Murphy concludes that the declining EROI of liquid fuels will make it increasingly difficult to sustain global economic growth.

Jackson & Smith [38] provide an optimistic view of global oil supply, based in part upon industry data on the production from individual fields and assumptions about the contribution of new technology and tight oil. They emphasize the economic and political factors influencing long-term supply and argue that resource depletion will not provide a significant constraint for at least two or three decades. Instead, they anticipate significantly lower rates of demand growth contributing to an initial 'undulating plateau' and subsequent slow decline of both conventional and all-oil production sometime after 2040. They anticipate a steady increase in upstream investment requirements and oil price volatility, leading to fuel substitution and improved energy efficiency.

Kumhof & Muir [91] use the International Monetary Fund's Global Integrated Monetary and Fiscal Model to assess the implications of oil supply constraints for the global economy. They initially assume that oil demand and supply are unresponsive to price changes and find that a small reduction in the growth rate of world oil production has only modest effects on gross domestic product. They then investigate three alternative scenarios in which: (i) there is less scope for substitution between oil and other energy resources; (ii) the contribution of oil to economic output is higher than conventionally assumed; and (iii) the reduction in global oil production is larger. Each scenario alone, but especially in combination, leads to a significant reduction in economic activity. Kumhof and Muir highlight the competing views about the plausibility of these alternative scenarios, the potential for nonlinear responses and the risk of greater impacts from oil depletion than orthodox economic theory suggests.

The remaining six papers investigate the potential of various mitigation options. In the first, Muggeridge *et al.* [6] provide a comprehensive overview of the nature, status and prospects for EOR techniques and their potential contribution to global oil supply. They begin by introducing the oil field recovery equation, summarizing the evidence on global recovery rates and explaining why these are typically low. They then examine the nature of EOR processes, the history of their application and the current status and contribution of EOR worldwide. They describe two, new, broadly applicable, low cost EOR technologies and give examples of existing and new EOR projects in different regions of the world. They conclude by highlighting the synergy between CO_2 sequestration and EOR, the further technical advances that may be expected and the need to accelerate global deployment.

Chew [92] describes the nature, extent and characteristics of 'unconventional' oil and gas resources. He reviews the extraction technologies and provides a detailed assessment of the size and recoverability of each resource. Chew finds that oil sands, extra-heavy oil and kerogen oil have large in-place resources, large areal extent, low exploration risk and the potential for long, stable production life. However, their low recovery factors, high cost, capital and energy intensity and long lead times make them only a partial substitute for conventional oil. Tight oil presents fewer recovery problems, but the resource base is modest. In contrast, unconventional gas resources appear significantly larger than those of unconventional liquids and continued growth in unconventional gas production could have significant impacts on the global oil market.

Höök et al. [70] provide an overview of CTL and GTL technologies, including their chemistry, technology, process efficiencies, input requirements, economics and environmental impacts. They argue that economic analyses have tended to underestimate costs and that a significant and locally concentrated amount of coal and gas would be required for these technologies to provide more than a marginal contribution to liquid fuel supply. Moreover, CTL and GTL production has significant environmental impacts which could slow or even stop their development unless adequate solutions can be found.

Timilsina [73] examines the potential contribution of biofuels to the global energy mix. Concern over the impact of biofuels on food prices has led several countries to reduce policy support, thereby slowing down the rate of production growth and increasing interest in second generation feedstocks. Given their relatively high costs, Timilsina estimates that biofuels are unlikely to contribute more than 5% of global transport fuel demand over the next 10–15 years. Projections of biofuels contributing one quarter of transport fuel demand by 2050 appear optimistic and would require significant technological breakthroughs. The contribution of biofuels to greenhouse gas emission reduction is also undermined by their indirect impacts on land use change.

Delucchi et al. [93] evaluate the status and prospects of electric vehicles (EVs) as a mitigation option. They begin by describing the technical features of battery, fuel cell and plug-in hybrid technology and their current state of development. They then examine the key technical challenges, including the cost, performance and lifetime of batteries and fuel cells, and the energy use, driving range, power and recharging time of different types of vehicle. They demonstrate the significant environmental benefits of EVs, argue that their lifetime cost can become comparable to that of conventional vehicles and suggest that problems of material scarcity can be overcome. Large-scale deployment hinges upon infrastructure development—including battery charging options and integration with low carbon electricity systems—and requires policies that bolster emerging markets, facilitate EV ownership and boost consumer confidence.

The final paper by *Freedman* [94] investigates the market and contextual factors influencing the uptake of EVs. The implementation of these technologies at scale requires careful attention to consumer-behavioural and policy challenges as well as adapting existing value chains and introducing new ones. The legacy of diverse urban planning and fuel taxation policies and varying degrees of consumer inertia will lead to very different rates of adoption in regional markets. In the absence of technology that provides a compelling consumer proposition, substitution of oil demand in OECD markets will be challenging, as will channelling exponential growth from the growing Asian market into less oil-intensive road transport solutions.

In combination, the papers provide a sobering picture of the challenges ahead. Most authors accept that conventional oil resources are at an advanced stage of depletion and that liquid fuels will become more expensive and increasingly scarce. The tight oil 'revolution' has provided some short-term relief, but seems unlikely to make a significant difference in the longer term. Even with a more sanguine view of global supply prospects, the large scale, capital intensity, long lead times and constrained potential of the various mitigation options point to the need for a coordinated response.

At present, rising oil prices are incentivizing the development of supply-side options whose large-scale pursuit would guarantee dangerous climate change (box 3). Avoiding this outcome requires instead the prioritizing of demand-side options and far-reaching changes in global transport systems. Climate-friendly solutions to 'peak oil' are available, but they will not be easy, they will not be quick and they appear unlikely to allow the majority of the world's population to achieve the levels of mobility currently enjoyed in the West. Lower mobility, in turn, implies a very different direction for future economic development. In sum, adapting rapidly and peacefully to oil scarcity in a manner that does not destroy the global environment provides humanity with a formidable challenge.

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