Exploring the undulating plateau: the future of global oil supply

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In this paper, we analyse the factors that will influence long-term oil supply and describe the future form of the global oil supply profile as an ‘undulating plateau’ rather than an irreversible, short-term peak or an ever upward trend of increasing production. The ultimate transition from a world of relatively plentiful and cheap oil to one of tight supply and high cost will be slow and challenging. An understanding of the signposts for the future path of supply and the drivers of that profile will be critical to managing the transition. The ultimate form of the global supply curve may well be dictated by demand evolution rather than a limited resource endowment in the longer term. Several factors will probably control future global oil supply. We believe that the scale of global oil resource will not constitute a physical supply limit for at least the next two or three decades. However, all categories of oil resources are already more expensive to develop than in the past, requiring high oil prices to stimulate supply growth. Lower rates of oil demand growth relative to economic growth, combined with more challenging supply growth, will probably lead to an undulating plateau sometime after 2040, with demand from non-Organization for Economic Cooperation and Development states continuing to dominate. Upstream investment requirements and oil price volatility will increase towards and beyond the undulating production plateau. In this new world, high oil prices will induce demand destruction, fuel substitution and ever increasing energy efficiency. As we discuss below, the fundamental differences between the IHS Cambridge Energy Research Associates’ (IHS CERA) view of the future of oil supply and many peak oil supply models are the timing of the onset of a dramatic slowdown in the rate of growth of supply and the existence or otherwise of
a production plateau. We do not dispute that supply will plateau and eventually fall; the question is when, how and at what price? As the plateau approaches, oil prices are likely to increase strongly, with some very severe spikes along the way.

1. Introduction

The upstream oil and gas business continues to grow the global oil resource base despite warnings of an ‘impending world oil shortage’ [1], the end of the age of oil [2] or indeed a point at which oil will effectively run out [3]. (See §6 for an explanation of various terms used in this paper.) While the cost base of the industry has been dramatically transformed over the past 10 years with operating and capital costs more than doubling since 2004 (IHS Cambridge Energy Research Associates (IHS CERA) Capital Cost Index [4]), the oil price has risen to new highs and conventional and unconventional resources that were uneconomic at US$20 per barrel are now transforming the energy landscape. Nowhere has this been more obvious than in the USA, where oil production from tight oil plays has grown from practically nothing to over 1 million barrels per day (mbd) in 2011, with continued growth to over 4 mbd in 2018 expected by IHS CERA based on a detailed study of over 20 separate North American plays. This example has shown again that the application of existing and new technology can be transformative. Until the great recession of 2008 began, fears of an imminent peak in production were persistent, but the impact of the recession on supply showed the important interplay among supply, demand and price.

We believe that oil will still be a major component of the energy equation through 2040 but that the landscape will evolve, and alternative fuels will build market share—particularly with the transition to an increasing use of gas [5,6]. We anticipate more efficient forms of transportation, and increasing gross domestic product per barrel of oil consumed, and some of the policies implemented to mitigate climate change will probably materialize and contribute to the changing energy balance, and reduce oil’s share of total energy consumed. It is not yet clear whether any of the mitigation policies will be pervasive enough to delay or soften the impact of the likely onset of an ‘undulating plateau’ [7]. But recent oil supply–demand–price dynamics are already giving us some strong clues about the future.1

2. Resource base not the limiting factor

The exact size of the global oil resource is not definitively known, and experience has shown that, for almost a century, resource estimates have been continually revised upwards as new discoveries are made, fields are better understood and new technologies applied [8]. Thus, there is support for the notion that resource growth is likely to continue for several decades. The size of the resource base is unlikely to be the limiting factor on future production. However, progress towards finding and developing future commercially viable resources will depend on the evolution of finding and development costs, technology, oil prices and other critical above-ground factors.

(a) Growing resource estimates, but at a price

BP reports that the proven oil resource base rose from 1033 billion barrels at the end of 1991 to 1652 billion barrels at the end of 2011 [9]. This trend is also borne out by the annual total volume of conventional (figure 1) and unconventional oil discovered globally. Volumes of conventional oil discovered each year have stabilized and even risen slightly since the mid-1990s—a change from the steep downward trend that started in the mid-1960s (figure 1). From 1964 to 1992,

1Note that data and analyses from the IHS proprietary databases and research are extensively quoted in this paper and supporting material is provided where possible.

2BP includes crude oil, extra-heavy oil, condensate and natural gas liquids in this estimate, but not biofuels or oil generated from natural gas (GTL or gas to liquids).
annual volumes discovered were on average falling by 5% per annum. From 1993 to 2010, average volumes discovered increased by 2% each year. During this time, however, oil prices rose from about US$20 to US$100 per barrel. Given the dramatic price signal, the lack of response in terms of new discoveries is indicative of a much more challenging and/or mature resource base than in the past.

Estimates of the total resource endowment of oil have similarly been constantly revised upwards. As early as 1920, the US Geological Survey (USGS) estimated remaining US reserves to be 7 billion barrels of oil, yet over the next 30 years the USA produced over 35 billion barrels and still had an estimated 28 billions remaining [10]. Sixty-one years later at the end of 2011, the USA had produced 243 billion barrels (IHS data) and still had over 30 billion barrels of proven reserves remaining [9]. Even that number is likely to be an underestimate because the proven reserves number cited does not include the undrilled and as-yet unproven tight oil resource.

When the USGS reviewed the results of four global resource assessments that it had completed between 1981 and 1993, it found that the total oil resource addition between 1983 and 1993 was over 500 billion barrels [11].

Even now resource estimates continue to show increases. IHS CERA’s current global compilation of discovered potentially recoverable resources of oil is now over 5 trillion barrels—more than double the 1993 USGS estimate that also included undiscovered potential (table 1). Similarly, the 2012 International Energy Agency’s (IEA) estimate of remaining reserves increased by 9% over its own estimate from the previous year [6].

There are three problems in attempting to estimate resource volumes. First, resource estimation is not an exact science, and the uncertainty and range of possible outcomes—whether at the scale of an individual field or of a basin—is huge. Second, extrapolation of recent trends of discovery into the future is never a reliable method of predicting commercially producible volumes over the long term, and no reliable statistical techniques have been developed that can accurately predict the potential remaining resources yet to be found [16]. Third, proven reserves estimates are directly proportional to oil price—which is constantly changing—and, in many cases, these reserves (for example, unconventional reserves) are only economically recoverable at relatively high oil prices. The global resource base is therefore a constantly moving target.

(b) New ideas, rising prices and technology drive future growth

It is difficult to predict what new ideas and technologies will emerge in the future. Yet for over a century, the power of new technologies and new ideas has always trumped extrapolation of past trends. One of the most recent and dramatic examples of this is the transformative growth in the production of gas from shale and of oil from shale and other very low-permeability rocks.
#### Table 1. Global resources, conventional and unconventional crude oil, IHS CERA compilation (billions of barrels). OPEC, Organization of Petroleum Exporting Countries. Sources: IHS [12–15].

<table>
<thead>
<tr>
<th></th>
<th>remaining technically recoverable</th>
<th>OPEC Middle East</th>
<th>other onshore and shallow water conventional</th>
<th>deepwater (more than 1000 feet (300 m))</th>
<th>Arctic</th>
<th>reserve growth</th>
<th>extra-heavy oil</th>
<th>kerogen oil extract</th>
<th>tight oil</th>
<th>exploration potential conventional oil</th>
<th>total global endowment</th>
<th>total remaining</th>
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<td>489</td>
<td>485</td>
<td>663</td>
<td>5456</td>
<td>4209</td>
</tr>
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</table>

*End-2010 numbers.

Reserves growth (or reserves upgrade) is a common process by which the reserves estimates of existing fields and discoveries increase over time as a consequence of a range of factors including additional technical data, analysis and application of new technologies.

Extra-heavy crude oil is any type of crude oil which does not flow easily. It is referred to as 'heavy' because its density or specific gravity is higher than that of light crude oil. Physical properties that differ between heavy crudes and lighter grades include higher viscosity and specific gravity, as well as heavier molecular composition. Extra-heavy oil is defined as having a gravity of less than 15 °API and is typically found and produced in Canada and Venezuela.

Kerogen oil, or shale oil, is an unconventional oil produced from oil shale by pyrolysis, hydrogenation or thermal dissolution of the rock. These processes convert the organic matter within the rock (kerogen) into synthetic oil and gas.
The power of new ideas and technology has had an enormous impact over the decades. While we cannot visualize the future with any certainty, there is no reason to believe that the industry will stop developing new technology and new game-changing approaches to exploration and production in the foreseeable future.

(c) Reserve growth: material gains from ‘small-addition ideas’

‘Reserve growth’ (field growth or reserve upgrade) is the phenomenon whereby more oil is ultimately recovered from a field than was originally estimated when the field was discovered or brought into production [8,17]. Such increases in the resource base do not necessarily come from disruptive technologies or paradigm shifts in thinking. Oilfield operators continuously make decisions about how to manage individual fields that either increase production or arrest decline rates. They decide, for example, where to drill infill wells, where to recomplete an existing well or when to implement a waterflood programme. Collectively, these activities have added billions of barrels to the resource base globally by finding oil in additional reservoirs or by improving recovery rates in already discovered fields.

Such activities led the USGS to speculate that such reserve growth will add more new oil resources in the USA than the discovery of new fields [18]. More recently, the USGS estimated that 665 billion barrels of crude oil could be added to the global resource base from reserves growth in existing fields outside the USA [19]. This speculation about reserves growth has already been borne out to some extent, for example in Indonesia. In that country, 53% of the new proven plus probable reserves added since 1983 were found in existing fields [20]. The implementation of waterflood programmes alone added almost 2 billion barrels of oil reserves over that same time period and allowed Indonesia to forestall the need for oil imports by over 3 years.

(d) Aggregate field decline rates

Oilfield production typically builds rapidly to a maximum rate, which may be maintained briefly or for some years (the ‘plateau’), and then enters a long period of decline until the field is depleted, which is the point at which oil can no longer be recovered economically. Most of a field’s reserves are in fact produced during the decline phase [21,22]. IHS CERA has undertaken a considerable amount of research on oilfield decline rates. The initial 2007 study, which included 890 fields, showed a global production-weighted decline rate of 6.1% for fields in decline [23].

An update of this study based on end-2010 production data [24], including 3490 fields, showed a slight decrease to 5.6%, similar to the value (5.5%) generated by Höök et al. [21]. We viewed this 0.6% difference as being driven by the larger dataset rather than any significant changes in decline rates over time. The larger dataset included a more representative sample of field sizes and geological settings.

However, to develop a true picture of overall global oil production decline rate, we also need to consider the contribution of fields on plateau and new fields coming on stream, which to some extent counterbalances the influence of fields in decline. On this basis, we estimate that the future global production-weighted aggregate decline rate will be 3.7%, which is slightly less than the 4% quoted by the UK Energy Research Centre in 2008 [22]. This global aggregate decline rate has a significant impact on how much supply will be required to meet future demand. For example, to achieve our projected global productive capacity of 113 mbd by 2030, some 65 mbd of new productive capacity will have to be found and brought on stream by that time. In the longer term, well past 2030, we expect the global aggregate decline rate to become lower, perhaps moving towards 3% because of the continuing strong influence of giant fields, which on a production-weighted average contribute more to the global average decline rate. This assumes that few new fields of any significant size will be found after 2030, and the giant fields found up until that time are likely to be contributing relatively more than the 60% of global production than they do today. Giant fields decline at much lower rates than small fields, especially in late life, and so the long-term aggregate decline rate will probably move towards the average decline of those dominant giant fields [24].
Table 2. Technological innovations in the upstream oil industry and their impact.

<table>
<thead>
<tr>
<th>year</th>
<th>technology</th>
<th>benefit</th>
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<tbody>
<tr>
<td>1893</td>
<td>anticlinal theory</td>
<td>concept of ‘where to drill’</td>
</tr>
<tr>
<td>1900s</td>
<td>rotary drilling</td>
<td>drill deeper</td>
</tr>
<tr>
<td>1914</td>
<td>seismograph</td>
<td>one-dimensional subsurface imaging</td>
</tr>
<tr>
<td>1924</td>
<td>well logging</td>
<td>subsurface rock and fluid properties</td>
</tr>
<tr>
<td>1930s</td>
<td>offshore drilling</td>
<td>access to new areas and basins</td>
</tr>
<tr>
<td>1960s</td>
<td>digital computing</td>
<td>two-dimensional subsurface imaging and data management</td>
</tr>
<tr>
<td>1970s</td>
<td>directional drilling</td>
<td>access to areas with surface obstacles</td>
</tr>
<tr>
<td>1980s</td>
<td>three-dimensional seismic</td>
<td>imaging revolution</td>
</tr>
<tr>
<td>1990s</td>
<td>three-dimensional simulation</td>
<td>predicting fluid movement</td>
</tr>
<tr>
<td>2000s</td>
<td>long horizontal drilling and multi-stage hydraulic fracturing</td>
<td>‘shale gale’ (q.v.)</td>
</tr>
<tr>
<td>2000s</td>
<td>next generation three-dimensional, four-dimensional (time lapse) and micro-seismic</td>
<td>further subsalt imaging capability, more efficient field development</td>
</tr>
</tbody>
</table>

(e) New technology equals new resources

The way new technology can provide access to new resources is best illustrated with offshore drilling. Some 40 years after the discovery of the Spindletop field in 1901—which itself was a turning point for world oil supply—offshore drilling technology began to be perfected and widely applied. The technology was originally tried offshore California 14 years before Spindletop, but it was not until the 1940s that offshore oil and gas resources out of sight of land became readily accessible. Since then, over 500 billion barrels of oil have been discovered offshore—resource volumes that in the 1940s would have been unimaginable. This is especially true of the 121 billion barrels that have been found so far globally in deep water (i.e. water depths greater than 1000 feet (300 m))—a category of resource whose ultimate potential still remains uncertain.

A number of transformative technologies that have shaped the upstream (i.e. oil exploration and production) business are summarized in table 2. Improved drilling technology allowed drillers to drill deeper in, for example, the North Sea and the Gulf of Mexico. Better subsurface seismic imaging techniques allowed meaningful exploration beneath salt formations (Brazil). More recently, long horizontal wells with multiple-stage hydraulic fracturing have allowed access to unconventional oil (and gas) resources in the USA and Canada.

(f) New ideas about where to explore

New ideas about where to look for and commercially extract oil and gas sometimes drive the development of the necessary technology. This is well illustrated by the ‘shale gale’ which has swept across North America. The idea that commercial volumes of gas could be produced directly from a shale source rock was only being considered 20 years ago (see [25] for earlier examples), but today North American shales are contributing 37% of total US gas production, and they are expected to provide 49% by 2035—more than double the 2010 percentage [13]. It was the idea that fractured shales could produce commercial volumes of gas that drove the application of groundbreaking existing technology as operators tried various combinations of horizontal drilling and multi-stage hydraulic fracture completions until they found the solution.
Once the technology was proved to produce commercial volumes of gas from shale, operators had the idea of applying the same technology to oil source rocks and other hard-to-produce reservoirs—collectively referred to as ‘tight oil’ plays. Helped by the economics of relatively high oil prices, tight oil has had and should continue to have enormous implications for future oil supply globally.

Production growth rates in tight oil plays, such as the Bakken Formation carbonates in North Dakota, the Niobrara Formation in Colorado and the Eagle Ford in South Texas, have averaged 50% annually. Crude oil and condensate production from the known established plays has grown from less than 20,000 barrels per day to over 1 mbd in just 11 years, and is now on a par with current production rates from the UK sector of the North Sea (1.2 mbd). Even plays like the Wolfberry–Wolfcamp in West Texas, which has produced oil since the 1950s, have been revitalized. In this play, production more than doubled between 2003 and 2011 from 73,000 to 213,000 barrels per day (figure 2).

Today, our estimate of the recoverable resources of tight oil plays in the USA is 40 billion barrels [26], but given the history of evolution of resource estimates globally we expect this figure to increase. It is likely that the application of new drilling and completion technologies will spread beyond North America. Tight oil reservoirs are already being tested in China, Russia and Argentina, and it is probable that there will be a substantial increase in tight oil reserves and production elsewhere, in ways we cannot precisely predict today. Nevertheless, our conservative, albeit approximate, estimate of tight oil resources outside North America is 464 billion barrels.4

Figure 3 illustrates the key point that technology has allowed the commercial exploitation of light oils from low-permeability rocks (US tight oil) and bitumen from high-permeability reservoirs (Canadian oil sands), neither of which would have been possible 20 years ago. The conventional reservoirs (porous rocks containing light-medium gravity crude) cluster is shown in the lower left of figure 3. Unconventional and the current technologies applied to them are in the remaining segments of the plot. Currently, there are no technologies for economically producing permeability–viscosity combinations in the central area of the diagram (for example, extra-heavy oil from tightly cemented sandstone).

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3This is 16 billion barrels more than the US Energy Information Administration’s [27] figure of 24 billion barrels, which included an analysis of only four oil plays. The IHS CERA estimate included 22 oil plays.

4IHS CERA internal estimate assuming that the ratio of tight oil to conventional oil outside North America will be similar to that ratio in North America following the methodology outlined for shale gas resource estimation [28].
Beyond these developments, we expect that other new technologies or combinations of existing technologies will emerge that will allow access to other combinations of rock and oil types for exploitation. As shown in Table 2, innovation in upstream technology has been a constant throughout the history of the oil industry, and there are no compelling reasons to assume a regressive change in this trend. There remain areas where oil is known to exist in large quantities but is currently inaccessible or uneconomical with existing technology. For example, there is currently no economically viable means of producing oil from kerogen in very low-permeability shale rocks other than by mining and retorting (heating and pyrolysis), such as that in China, Jordan and Estonia.

Technology historically has facilitated access to new resources, and while technology may not always improve our ability to find and extract oil in the future, it is highly probable that it will play an important role in economically accessing other hydrocarbon resource types (e.g. methane hydrates) and reserves in operationally and technically challenging areas, for example the Arctic offshore.

3. Above-ground factors

The existence of a material resource base and development of viable below-ground play concepts are at the core of the oil supply equation. However, it is predominantly above-ground factors that drive investment and activity [29]. Sufficient investment will be crucial to providing adequate future oil supply [6]. Relevant factors include basic economics, demand, oil price and more specifically the regulatory and operating environment of the host countries. Gaining access to material investment opportunities so that oil can be found and developed is one of the critical determinants of the success of the upstream business and the scale of future oil supply.

Evolving geopolitical events can also have a major, disruptive impact on supply that can last for decades, for example

— the Arab oil embargo in 1973 (the ‘first oil shock’);
— the 1979 Iranian revolution (the ‘second oil shock’);
— the Arab spring;

Figure 3. Permeability–viscosity framework for conventional and unconventional reservoirs. CO₂, carbon dioxide; EOR, enhanced oil recovery; SAGD, steam-assisted gravity drainage. Source: IHS CERA.
— current sanctions against Iran;
— resource nationalism in some Latin American countries; and
— the great recession of 2008.

What is difficult is predicting these events and understanding their immediate and longer term impact. In the future, we expect to see volatility driven by geopolitical events—especially in times of very low spare production capacity—and these events will have an inevitable effect on supply and demand.

The ease and efficiency of exploiting oil can be very different in different countries. For example, onerous fiscal terms, stringent requirements for local provision of goods and services or import fees, which can make it difficult to import suitable equipment, can greatly inhibit investment. We have also seen recently that some countries (e.g. France) have imposed a blanket ban on hydraulic fracture completions of wells in response to environmental and water-use concerns.

Host governments have a vested interest in encouraging investment and boosting production that feeds into economic well-being and job creation as well as having longer term implications for energy security. But the complexity of the oil supply equation will increase. The spectrum of different oil asset classes—conventional, unconventional, gas-related liquids, etc.—continues to grow, and the level of operational complexity is likely to increase. In the future, we expect to see much more attention paid to optimizing oil production from mature fields as many countries gradually come off their plateau production and discoveries become smaller, and there we also expect a dramatic increase of unconventional hydrocarbons in the mix. All stakeholders will need to climb the learning curve quickly and cooperate to ensure an optimum outcome.

All categories of oil resource are now more expensive to develop, requiring high oil prices to generate an economic return. New high-cost Canadian oil sand developments are commonly announced after a period of relatively sustained high oil prices and are just as quickly delayed or postponed if oil prices drop for any substantial period of time, as in 2008. Similarly, interest in exploration in new remote or technically challenging areas depends heavily on capital requirements and the perceived long-term view of oil price that would make such high-cost environments economical. High oil prices from the mid-1970s into the early 1980s and between 2004 and 2007, for example, coincided with unprecedented levels of exploration activity, as reflected by the strong increase in the area awarded globally for investment in exploration in the latter period (figure 4). Correspondingly, low levels of activity were seen during the oil price collapse of the mid- to late 1990s.

Oil price also drives innovation in different ways. When there are sustained low oil prices, operators are incentivized to find ways of saving money and improving efficiency through process improvements. When oil prices are high, operators look to take advantage by taking more risk and identifying new basins and plays to explore or by developing technologies to optimize development of known high-cost resources.

4. Scenarios of the future

IHS CERA has developed three scenarios to frame the future of energy: Global Redesign, Metamorphosis and Vortex. Global Redesign is the base case and the capacity model presented in this paper was developed with this scenario in mind.

Global Redesign imagines a world in which reinvigorated post-recessionary market forces and a shared interest among major powers to expand trade and investment foster robust economic growth. Oil prices decline below US$100 per barrel in the short term but post-2015

Metamorphosis envisages a sustained increase in oil prices, energy security concerns and long-term policy and commercial support for renewable energy technologies. There are revolutionary changes in energy technology and consumer behaviour and a dramatic reduction in greenhouse gases.

Vortex is accompanied by economic volatility and a second great recession with a long slowdown in economic growth. Energy investment slows and technology and efficiency gains are muted.
gradually increase. Economic growth becomes increasingly concentrated in Asia, with many Asian economies enjoying healthy financial conditions. Disputes over greenhouse gas policies and nuclear proliferation create tensions that lead to periodic doubts about the durability of globalization. Such tensions and a shared interest in sustaining globalization lead to the creation of new international institutions as other countries adapt to manage a complex world. At any one time, we see elements of all three scenarios. The Global Redesign outlook assumes robust oil supply growth through 2030 (see below).

Figure 4. Gross acreage awarded annually by region. Frontier North America includes only Alaska, Canada Beaufort Sea/Mackenzie Delta area, Canada east coast and deepwater Gulf of Mexico. FSU, former Soviet Union. Source: IHS CERA.

(a) Liquids productive capacity outlook: definitions and methodology

From a comprehensive analysis of decline rates and knowledge of individual projects and fields, IHS CERA has made projections of future productive capacity for all oil-producing countries as well as those with material future exploration potential. The impact of fiscal, operating and political drivers within each oil-producing country—and those with future potential such as French Guyana or Greenland—are considered within the framework of our global energy scenarios.

In this study, we include conventional crude oil, extra-heavy oil, gas to liquids (GTLs), coal to liquids (CTLs), natural gas liquids (NGLs), oil from shale and biofuels in our definition and outlooks for liquids productive capacity. We have also included the anticipated impact of the tight oil boom currently underway in the USA.

The analysis includes a detailed evaluation of all fields in production (FIP), fields under development (FUD), fields under appraisal (FUA) that are likely to be economical, and an assessment of volumes expected to be produced from fields that are yet to be found (YTF). This takes into account the prospectivity of each area, exploration and discovery trends, the impact of forthcoming licensing rounds and above-ground factors, for instance access limitations. Each of these classes of productive capacity represents increasing levels of uncertainty concerning the likely volumes and timing (figure 5 and table 3). Our outlook is updated twice annually.

Productive capacity is the maximum sustainable level at which liquids can be produced and delivered to market. Productive capacity is different from production, which is the actual amount produced at any time.

The uncertainty hierarchy is FIP < FUD < FUA < YTF.
based on new information about field-level production and decline rates, as well as new project sanctioning, cancellation or postponement of new developments, delays in development projects already underway and new information that might impact YTF (figure 5 and table 3).

(b) Liquids productive capacity: results

Our 2012 analysis of future global productive capacity within the Global Redesign scenario yields the following conclusions:

— Based on our outlook, we expect liquids productive capacity to rise from the current level of 93 to 113 mbd by 2030, with no peak anticipated by that time.
— We expect that production growth will be dominated by unconventional components, and conventional crude oil production growth (buoyed by US tight oil, which is compositionally conventional) will be modest.
— Both OPEC and non-OPEC production (conventional and unconventional) should grow strongly through 2030, with some of this being underpinned by gas-related liquids.
— With the recent emergence of the tight oil plays in North America and the presalt conventional oilfields in Brazil, the balance of supply growth has shifted westwards. While many countries are past their production peak, others (e.g. the USA, Canada, Brazil and Iraq) are expected to show significant growth in the next 18 years, but not without considerable above-ground risk. Even oil supplies in countries past their oil production peak, for example Norway, have demonstrated a new found capacity for growth from emerging plays and (as in Colombia) by stimulating new investment.
— Among some of the major producers in decline, such as Iran, Mexico and Venezuela, the main drivers are political rather than a shortage of resource.
— High oil prices have stimulated investment in exploration since 2002, and a number of new plays have opened (e.g. in the Brazil subsalt, Ghana, the Falkland Islands, French Guyana and onshore East Africa). This includes plays in countries seemingly mature for exploration and lacking potential for new giant fields (e.g. Norway).
Table 3. IHS CERA global liquids capacity outlook to 2030, Global Redesign scenario (million barrels per day).

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<td>0.2</td>
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<td>0.4</td>
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<td>conventional crude and condensate</td>
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<td>75.32</td>
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<td>0.90</td>
<td>3.96</td>
<td>5.03</td>
<td>5.22</td>
<td>5.25</td>
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</table>

A number of activities could drive this outlook for liquids supply to higher levels:

— **Discovery of material volumes from tight oil reservoirs in areas outside of North America.** The pace at which liquids production from outside of North America will increase is not yet known, but in the not too distant future we expect this to become an important new source. At the time of writing, our supply forecast does not include any volumes of new tight oil supply outside of North America.

— **Widespread application of CO₂ and steam for enhanced oil recovery (EOR).** Widespread sequestration of CO₂ and a global shale gas revolution would address the primary issue of sourcing CO₂ and using natural gas to generate steam for EOR [30].

— **Expanded use of horizontal wells and hydraulic fracturing** as a means of increasing recovery from mature and heavily depleted conventional plays.

— **Breakthroughs in GTL and CTL technology.** Currently, only a small volume of GTL/CTL production is included in our Global Redesign outlook.
Other technological breakthroughs and ideas. Two examples, which are in experimental stages, include microbial EOR and techniques to convert kerogen in oil shale to liquid crude oil using an in situ process. The potential resources of oil shale are estimated to be 4887 billion barrels in-place [31], but currently yields are quite low, of the order of 10%.

5. Post-2030: views of future supply

It is impossible to model a definitive, unique oil supply outlook [7]; there are too many above-ground and below-ground variables and uncertainties [32]. In this paper, we define the limits to the broad range of likely outcomes that constrain the longer term reality, which are somewhere between the resource constrained peak oil model [1,3,33,34], which reflects an imminent, irreversible supply crisis, and the ‘ever upwards’ view of steadily increasing supply. We also describe our base case scenario through 2030, which we consider the most likely outcome. In managing the transition from the age of oil to a new energy portfolio, it is critical to understand the limit and shape of the future supply curve.

In the following sections, we discuss the elements of the two limiting scenarios and describe our preferred view of an undulating plateau, which shares some similarities with the peak oil model—the most important being that global oil supply will eventually start to decline. But there are some very significant differences, including timing, an understanding of drivers of supply, the underlying attitude towards technology and our view of how the upstream oil industry develops.

(a) Continuous supply growth: ever upwards?

The ever upwards model reflects an unlikely scenario of a world in which oil supply can continue to grow steadily into the future from current historically high levels. Although we believe that this is the likely outcome up to 2030 and perhaps even as far as 2040, there are severe long-term constraints beyond that. Put simply, this utopian view is not supported by the fact that the global hydrocarbon endowment, whatever that turns out to be, is finite and sufficient only to support limited and slow short-term capacity growth from current levels. In the short term, it should be possible to continue capacity growth at levels necessary to meet the current pace of demand growth; but in the long term, the growth path will flatten and eventually turn downwards.

With continuing strong long-term global demand growth (say 1% per annum), supply will soon become persistently tight and prices will respond accordingly. Resource scarcity, oilfield depletion, increasing upstream costs and persistently high oil prices will start to drive oil slowly out of the global energy equation. In a short time frame, any strong but volatile demand growth would not be met by the necessarily low levels of supply growth envisaged in this model. Because oil is ultimately a finite resource, supply growth by definition cannot be infinite—and we have seen that play out already, with long-term prices (US$80–100) that were once beyond imagination now considered to be reasonable. In practice, we can access portions of the ultimate resource base at ever higher costs, but at some point—well before exhausting the entire resource base—it will become more economical to use gas and alternative sources of energy, for example solar power. Over the past 10 years, we have entered a new, far higher cost base in the evolution of supply, which is a step in that direction.

(b) Short-term peak?

Many studies have predicted an imminent peak of global oil supply, followed by a decline [1,33–35], but the peak has yet to materialize. Shortcomings of such studies have been reviewed elsewhere [36,37].

Many of these studies of future supply are constrained by the current view of the global resource endowment and consider only ‘2P’ (proven plus probable) conventional oil reserves.
Such studies frequently assume that very limited volumes of new conventional oil will be discovered in the future and also assume that emerging unconventional resources will be inadequate or too expensive to support significant future growth [3,33]. But past studies have generally underestimated the resource volumes’ contribution from new discoveries (see §2).

Typical studies of peak oil assume that a third to a half of the known global 2P conventional endowment has been produced already, the point where empirical evidence shows that production in many countries peaked [38]. While this concept is reasonable, we still have no reliable view of the ultimate global resource base and it is very unlikely that half the ultimate resource base has been produced to date (table 1), suggesting that we are nowhere near the peak of oil production.

Price is also key to demand and supply dynamics, which are central to this debate. It is the ultimate interplay between supply and demand—and not simply a peak in production—that makes aspects of the peak oil model important. We expect that the estimate of the likely net global conventional oil endowment will continue to grow in the medium term, driven by economic factors. This view of a robust, growing resource base—combined with a very strong pipeline of new oilfield development projects and continued strong investment in upstream—supports IHS CERA’s view of capacity growth of both conventional and unconventional liquids through 2030 and beyond (see also [5,13]).

The recent post-recession decline in the growth rate of global oil demand has delayed the onset of any possible peak in total oil production by a number of years (as did the earlier ‘oil shocks’ of the 1970s). It is still too early to tell exactly how demand will recover after the recession and global demand downturn that began in 2008, but the recession has certainly bought some time. The start of the 2008 recession, falling demand growth, the tight oil boom and an increasing consensus about relatively plentiful supply have calmed fears about an imminent peak, although the current oil price remains high by historical standards [9].

The fundamental differences between the IHS CERA view of the future of oil supply and many peak models are the timing of the onset of a dramatic slowdown in the rate of growth of supply and the existence or otherwise of a production plateau (figure 6). We do not dispute that supply will plateau and eventually fall; the question is when and how. These differences are critical.

A short-term peak followed by a rapid production decline is not totally out of the question. The following factors could drive this scenario:

— collapsing demand—take away demand and there is no need to produce;
— stagnant investment in the upstream business;
— no upside hydrocarbon potential; therefore, no more resources discovered;
— no significant future growth in unconventional liquids productive capacity;
— political disruptions; and
— inability of the upstream sector to respond to complex markets/volatility.

Although the full force of these factors that might induce a peak are unlikely to unfold in the short term, an informative market dynamic has emerged in recent years (as a consequence of the 2008 recession), during which a major decline in demand simultaneously drove production down and increased spare capacity to around 6 mbd in 2008/2009. This was not the peak. Spare capacity has subsequently declined to approximately 2 mbd and created renewed tension in oil markets. Although 2008–2009 was not the peak of global liquids production, we saw total liquids productive capacity rise from 2009 levels of 89 to 93 mbd in 2012. Fundamental market dynamics kicked in yet again, as they will do for decades to come.

In its central New Policies Scenario, the IEA [6] estimates that the peak of global conventional crude oil production (excluding NGLs, extra-heavy oils, biofuels and GTLs) occurred in 2008 at 70 mbd. In this scenario, it projects that conventional crude supply will fall in a range from 65 to 69 mbd in the period to 2035—but it explicitly excludes the contribution from tight oil plays which are deemed to be an unconventional source. While extraction methods for tight oil are unconventional, the light, sweet crudes are geochemically conventional; refineries are interested...
in the price and chemistry of the oil, not production methods. If we include IHS preliminary estimates of tight oil potential outside North America in the equation, it is likely that we will see continuing, gradual growth of crude oil supply to between 90 and 95 mbpd by 2030, and with no peak in sight by that time. The recent OPEC outlook to 2035 [5] also does not show a peak in crude oil supply, but rather a plateau of crude production that starts near 2025, which is more consistent with our outlook and that of the IEA Current Policy Scenario [6].

Recent events have provided important clues about the future path of supply and market reactions. It is critical meanwhile not to confuse the normal dynamics of supply/demand and prices with some of the longer term structural changes we might expect at the onset of the undulating plateau.

(c) Undulating plateau?

The future of oil supply has a multitude of potential outcomes. The IHS CERA view, our Global Redesign scenario to 2030, is based on an understanding and bottom-up analysis of key below-ground and above-ground factors. In our recent 2012 review of the future of global oil supply (IHS internal analysis), based on our Global Redesign productive capacity scenario, we concluded that global liquids productive capacity can continue to grow to as much as 113 mbpd in 2030 (table 3).

The IHS CERA view of supply to 2030 reflects that there is no shortage of hydrocarbon resources that can be converted into commercial liquid supply to meet anticipated demand growth through that time. However, meeting this demand will pose challenges. For example, conventional and especially unconventional oil supply will need to grow significantly and major investment will need to be increased to sustain growth at the required levels. We estimate that upstream spending will grow from US$1218 billion⁹ in 2012 to US$1674 billion in 2016, representing a 220% increase from 2006. This trend in cost escalation is likely to continue, but at variable rates.

A strong inventory of new development projects has evolved to support this growth, partly as a response to the high oil prices of the past 5 years. We estimate that field upgrades will continue to contribute significantly to the global resource inventory, and that material discoveries will continue to drive the recent trend of increasing annual volumes discovered (figure 1), although

⁹Note that upstream spending includes operating costs and capital expenditure including pipelines and liquefied natural gas projects.
the annual discovery rate remains about a half of annual consumption [6]. The upstream industry is doing a good job of replacing reserves and growing production at current prices through both exploration and field resource upgrades—for now [9].

The aftermath of the recession and higher upstream costs have inhibited upstream investment and activity somewhat since the beginning of 2009. But the upstream sector has continued to perform well recently, as reflected by the additional volumes of oil discovered globally and the revolution in tight oil production in the USA driven by high oil prices. Despite concerns over remaining long-term resource potential [22], Iraq and Brazil have come to the fore in the past 5 years as particularly important potential engines of supply growth in the next 10–15 years. But there are always risks linked to economic factors, investment patterns and geopolitical events that will disturb these current views of future supply.

Longer term, there are likely to be problems finding and developing the large volumes of new oil needed to replace the depletion of current oilfields and provide the net positive growth required to meet expected increases in demand. Based on our Global Redesign scenario sometime around 2040, we anticipate that an undulating plateau of supply will set in before the long-term decline of total global liquids production begins. Today it is impossible to predict exactly when this turning point will occur, but for the purpose of this discussion we assume that the undulating plateau of total liquids supply will appear after 2040, given the strong foundation being laid now by the upstream sector, especially in the area of tight oil (figure 6).

Post-2040, persistent long-term oil demand growth of around 1% per year, which is typical of the current market [6], is unlikely to be sustainable given the volume of new production capacity that will be needed to meet this demand. The upstream business will be unable to invest enough capital fast enough in the context of a tightening resource base to respond to the combination of depletion of a rapidly maturing asset base and a need for consistent, strong supply growth.

Although producers are currently able to find and develop adequate volumes of new oil from sources such as unconventional and deepwater plays, finding and development costs have doubled in the past 10 years (IHS CERA Upstream Capital Costs Index and Upstream Operating Costs Index), and we expect capital and operating costs to continue to gradually increase as oil is discovered in more remote and complex environments. In addition, inflationary and competitive pressures for limited oilfield service sector capability will continue to drive up costs and constrain investment. The scale of effort needed to maintain supply growth in the long term will ultimately not be achievable as most of the world’s largest fields reach late maturity in production terms and discovery sizes continue to dwindle. Although great efforts will be made to exploit high-cost oil from unconventional sources and remote, harsh environments and Herculean efforts will be needed to exploit mature assets, the supply–demand equation will eventually fail to balance as gradual decline sets in.

We believe that there will be a transition to an undulating plateau in production over a relatively short period. We also believe that a sustained period of plateau production prior to any decline is more likely than a sudden and dramatic fall. A plateau is more likely owing to the dynamics of price, supply and demand.

As the plateau approaches, oil prices are likely to increase strongly (with some very severe spikes along the way) and demand growth will necessarily slow down as price rises ultimately result in some degree of demand destruction. We observed demand destruction occurring when the oil price reached US$60 per barrel in 2005, primarily from developed, industrialized economies. Even in many major oil-producing countries, where prices are kept low owing to government policy, price subsidies cannot be sustained in the long term, and this means that consumers will ultimately be forced to modify their consumption patterns as a consequence of rising prices. We believe that real oil prices substantially above current levels (US$100 per barrel) will be difficult to sustain in the long term, but we have been surprised before. There is also a major limitation in that the major non-Organization for Economic Cooperation and Development (OECD) countries may aspire to OECD levels of oil consumption (12–25 barrels per capita annually), but even at their current population levels this cannot happen because it would require a doubling of the current production of oil globally within a relatively short period of time.
In a higher cost world, we also anticipate that eventually no country is likely to sustain significant volumes of expensive spare capacity. With the spare capacity buffer removed, the global supply and demand profiles will start to collide in times of strong economic growth or weak energy prices, initially for short periods, when we will probably see a step change in oil price and increasing levels of extreme volatility. Oil price cycle times will continue to shorten.

Whereas the demand for oil is almost immediately affected by increasing oil prices, supply growth does not occur so quickly because it can take up to 7 years to develop new sources. This means that price spikes should initially result in almost instant demand destruction rather than an increase in the oil supply, and with new supply only able to come on stream relatively slowly this should provide incentives for the development of alternative sources of energy (as we have seen since 2000). High prices will necessarily slow consumption growth and incentivize the production of whatever alternatives may then exist. Oil will simply price itself into a shrinking market over the long term.

Longer term, the undulating plateau will start to turn down, and production will slowly fall. We think that a further rise in oil prices can open up new sources of even higher cost oil for a time, but that this is unlikely to provide enough new supply to offset declining output from existing fields, even with a relatively high case view of total resource endowment. However, it is the impact of prices on new supply and demand destruction which we think is likely to result in a period of volatility in price and supply, rather than a sharp peak, followed by a steep decline.

Anticipating and recognizing the signposts for the onset of the undulating plateau is critical, because there is a danger that we will ignore the signs when the plateau finally approaches. Of course, identifying the differences between the resource-restricted peak and the less catastrophic demand-driven view of the future is also crucial.

From an upstream and oil markets perspective, the signposts for the course of future supply are numerous, but the most important are the following:

— the trend of total reserves replacement will begin to stall over the long term;
— conventional oil productive capacity will start to plateau between 2025 and 2030, well before the aggregate total liquids reach the undulating plateau sometime after 2040;
— non-OPEC capacity growth will stall before the onset of the undulating plateau;
— there will be sustained tight supply;
— oil prices will become increasingly volatile and then rise; sustained high oil prices will contribute to destruction of significant amounts of demand; and
— alternative technologies, infrastructure and fuels will become economically attractive in sectors traditionally dominated by liquid hydrocarbons.

(d) Threats and challenges

In our model for the undulating plateau, we have described the broad form of the long-term supply curve, but the exact detail is not clear. We are confident, however, that there will be a great deal of volatility in prices, supply and demand on the back of the curve.

Through to the middle of this century, we anticipate that there will be no resource constraint at a geological level—that is, no absolute lack of resources, but at some stage there will be an inability to establish new supply fast enough to meet growing demand. Costs, oil price and especially economic factors that manifest themselves in the evolution of demand will drive the long-term curve. We expect the turning point or final peak of global oil supply to appear sometime after 2040, though right now it is not possible to predict exactly when. A number of factors could upset this view of future supply:

— sustained above-trend growth in global demand;
— inadequate investment in upstream in the short term, feeding though to tighter long-term supply;
— upstream technology failing to deliver the breakthroughs needed to boost supply;
— unconventional liquids production unable to be scaled up quickly enough to generate the
growth in capacity needed through 2030;
— geopolitical factors such as terrorist activity or unstable governments;
— slower than expected penetration of alternatives to oil and a slower increase in energy
efficiency; and
— a much stronger global response to the anticipated long-term impact of climate change.

Meanwhile, both a short-term peak or an ever upwards increase in supply both seem highly
unlikely outcomes, and oil will remain a significant part of the global energy equation for decades
to come.

6. Definitions

(a) Resource definitions as used in this paper

Conventional oil. Any liquid hydrocarbon resource that is extracted using ‘traditional’ oilfield
methods.

Unconventional oil (or unconventionals). As used herein, this refers to resources that require
special drilling, completion and/or treatment techniques in order to be produced in commercial
quantities. This is caused by either the oil being exceptionally difficult to produce (e.g. extra-
heavy oil with gravity below 11°API) or the rocks being difficult to extract oil from (e.g. very
low-permeability sandstones, carbonates and chalk or shale). Unconventional oil does not include
heavy oil typically defined as being in the oil gravity range of 11–22°API, which will generally
flow without special techniques but where steam EOR is commonly applied for economic
reasons. We include ‘tight oil’ in the unconventional category because of the required completion
techniques. Nevertheless, it must be recognized that the oil itself is typically a light sweet crude
requiring no further treatment to be produced.

Total resource endowment or resource base encompasses all quantities of petroleum (recoverable and
unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered,
plus those quantities already produced. In some instances, we refer specifically to future resources
which mean undiscovered volumes only. And, in some instances, we refer specifically to ‘oil’ resource or ‘liquids’ resource to clarify that we are excluding other hydrocarbon types.
Furthermore, it includes all types of petroleum whether currently considered ‘conventional’ or
‘unconventional.’

Technically recoverable resources are a subset of total resource endowment or oil in place. It refers to
resources that can be recovered using today’s technology. It includes volumes already discovered
as well as those estimated to be found in the future.

Commercially recoverable resources (or economically recoverable resources) are a further subset of
the technically recoverable category which is dependent upon oil price and the cost to develop.
Also refers to volumes recovered and volumes estimated to be found in the future.

(b) Other petroleum industry-related definitions

Tight oil is a petroleum play that consists of light crude oil contained in petroleum-bearing
formations of relatively low-porosity and low-permeability shale, limestone or sandstone. It
uses the same horizontal well and hydraulic fracturing technology used in the recent boom in
production of shale gas to enable commercial rates of production to be attained.

Kerogen is the naturally occurring, solid, insoluble organic material that occurs in source rocks
and can yield oil on heating (the fraction that is soluble in organic solvents is called bitumen).
Decline rate is the percentage annual rate at which production from a well, field or region declines following peak or plateau production.

Waterflood is a method of secondary recovery in which water is injected into a reservoir to displace residual oil.

Depletion of a field (either oil or gas) is the point at which the hydrocarbons can no longer be economically produced. Typically, as much as 70% of oil in oilfields and 35% of gas in gas fields still remain in the ground at that point. Some of these may remain technically recoverable but, owing to high operational costs, are no longer economically viable to produce.

A source rock contains kerogen in sufficiently high concentrations necessary to generate the large volumes of oil and gas found expelled and trapped in sedimentary basins worldwide.

Condensates are a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but, when produced, are in the liquid phase at surface pressure and temperature conditions.

Proven plus probable reserves (2P) are, according to the Society of Petroleum Engineers (1997), reserves that are commercially recoverable which have at least a 50% chance of being recovered from the field.

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