From oil resources to reserves

Should we worry about scarcity, or abundance?

Highlights

- Estimates of ultimately recoverable resources of oil continue to increase as new technologies, such as multi-stage hydraulic fracturing, unlock types of resources, such as light tight oil, that were not considered recoverable only a few years ago. Light tight oil resources worldwide are still relatively poorly known but, on current estimates, represent some 6% of total remaining recoverable resources.

- Our latest estimates for remaining recoverable resources show 2 670 billion barrels of conventional oil (including NGLs), 345 billion of light tight oil, 1 880 billion of extra-heavy oil and bitumen, and 1 070 billion of kerogen oil. Cumulatively, 790 billion barrels of oil need to be produced in total to meet projected demand in the New Policies Scenario.

- High oil prices in recent years have resulted in an increase in total proven oil reserves, which stand at around 1 700 billion barrels, as the industry has been proving up more reserves than it has produced. Discovery rates of conventional oil and the average size of discovered fields have stabilised, at about 14 billion barrels per year and 50 million barrels respectively, after the drop observed in the second-half of the last century. However, future discoveries are expected to be smaller, contributing to higher per barrel costs for exploration and production.

- Nearly 80% of the world's proven-plus-probable reserves of conventional and unconventional oil are controlled by national oil companies (NOCs) or their host governments. The rest is controlled by privately-owned companies: 7% by the seven major international oil companies and 13% by independents. Almost all of the reserves held by NOCs (outside Venezuela) consist of conventional oil.

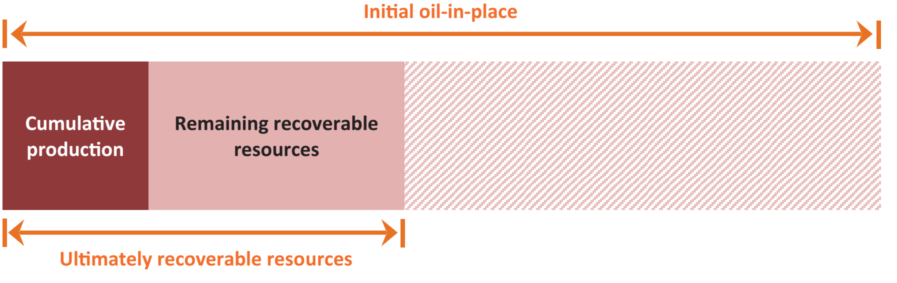
- By increasing recovery rates in conventional reservoirs, enhanced oil recovery (EOR) technologies are currently estimated to have the potential to unlock another 300 billion barrels on top of the current resources estimates, an amount comparable to the resource additions from light tight oil. Injection of CO_2 into reservoirs is a proven EOR technique and, if the incentives are right, could also develop as a way to store CO_2. Realising the full potential of EOR technologies is hampered in practice by the complexity of projects and the shortage of the necessary skills in the industry.

- Detailed oil supply cost curves for 2013 and 2035 suggest that the marginal cost of producing a barrel in the New Policies Scenario is significantly below the oil price in this scenario. Risks affecting investment in oil supply and difficulties faced by the industry to develop new resources at a sufficiently high pace push oil prices above the marginal cost of production.

Classifying oil

Understanding oil resources is essential to any analysis of the future prospects of the oil sector. These resources are large, but they are finite and unevenly distributed around the world. Even in a country with a significant endowment of oil, production will usually start decreasing as the depletion of its resources becomes significant. Though there is no hard-and-fast rule, production often starts decreasing when recoverable resources are more than 50% depleted (an empirical observation, highlighted by many analysts and often presented as an argument supporting the peak oil theory).[1] The main reason for the decrease is that, in a given area, oil from the easiest, lower cost, larger reservoirs is usually produced first, followed later by oil from the smaller, more difficult and more costly accumulations. This means that, as depletion increases in a basin, the cost of new developments also goes up; if oil prices do not rise correspondingly (which can happen if other countries or regions still have low-cost oil), production will decrease as the depleted country is out-competed by other players. Alongside understanding the limits imposed by demand for oil and government policies, understanding resource depletion in each country or region is a big part of projecting how much various countries will be able to produce in the future.

Figure 13.1 ▷ Classification of oil resources



Notes: Remaining recoverable resources are comprised of proven reserves, reserves growth (the projected increase in reserves in known fields) and as yet undiscovered resources that are judged likely to be ultimately producible using current technology. There are different classification systems for oil reserves and resources, as discussed in this chapter. Ultimately recoverable resources (and therefore remaining recoverable resources) can be defined either as technically recoverable, *i.e.* producible with current technology, or as technically and economically recoverable, meaning that they are exploitable at current oil prices. The resource numbers are for technically, but not necessarily economically, recoverable resources.

To determine depletion, one needs to know how much oil has already been produced and also have an estimate of how much can ultimately be produced (Figure 13.1). The latter figure, for ultimately recoverable resources (URR), is a critical variable for the modelling and analysis, much more so than the (often more widely-discussed) number for oil reserves. URR gives an indication of the size of the total resource base that is recoverable with

1. The interplay between depletion, prices and demand, and the impact of unconventional resources on the peak oil debate is discussed in the Spotlight in this chapter.

today's technologies, both the part that is known (either because it has been produced already or because it has been "proven", *i.e.* its existence established with a high degree of probability) and the part that remains to be found in existing and in undiscovered fields. Reserves are a sub-set of URR and, while important in some cases as an indication of what companies have decided to line up for development, do not provide a complete picture either of the resource base or of long-term production potential.

Our estimate of global, ultimately recoverable resources of conventional crude oil stands at some 3 300 billion barrels. Of this, 1 136 billion barrels, or 34%, have already been produced, leaving a remaining recoverable resource base of 2 200 billion barrels (Table 13.1). Adding natural gas liquids (NGLs)[2] and unconventional oil more than doubles the size of the recoverable resource. However, resource estimates are inevitably subject to a considerable degree of uncertainty; this is particularly true for unconventional resources that are very large, but still relatively poorly known, both in terms of the extent of the resource in place and judgements about how much might be technically recoverable. These uncertainties, as well as the techniques and costs associated with developing oil resources, are the focus of this chapter.

Table 13.1 ▷ Remaining recoverable oil resources and proven reserves, end-2012 (billion barrels)

	Conventional resources		Unconventional resources			Totals	
	Crude oil	NGLs	EHOB	Kerogen oil	Light tight oil	Resources	Proven reserves
OECD	**315**	**102**	**811**	**1 016**	**115**	**2 359**	**240**
Americas	250	59	808	1 000	81	2 197	221
Europe	59	33	3	4	17	116	14
Asia Oceania	6	11	0	12	18	47	4
Non-OECD	**1 888**	**363**	**1 069**	**57**	**230**	**3 606**	**1 462**
E.Europe/Eurasia	347	82	552	20	78	1 078	150
Asia	96	27	3	4	56	187	46
Middle East	971	168	14	30	0	1 184	813
Africa	254	54	2	0	38	348	130
Latin America	219	32	498	3	57	809	323
World	**2 203**	**465**	**1 879**	**1 073**	**345**	**5 965**	**1 702**

Notes: Proven reserves (which are typically not broken down by conventional/unconventional) are usually defined as discovered volumes having a 90% probability that they can be extracted profitably. EHOB is extra-heavy oil and bitumen. The IEA databases do not include NGLs from unconventional reservoirs (*i.e.* associated with shale gas) outside the United States, because of the lack of comprehensive assessment: unconventional NGLs resources in the United States are included in conventional NGLs for simplicity.
Sources: IEA databases; OGJ (2012); BP (2013); BGR (2012); US EIA (2013a).

2. NGLs are liquids produced within a natural gas stream; they are separated from the gas flow either at the well site (field condensate) or at gas processing plants. Field condensate is reported as part of crude oil in some countries (OECD in particular) and part of NGLs in others (OPEC in particular).

Box 13.1 ▷ Light tight oil, conventional or unconventional?

We use the term light tight oil (LTO) to designate oil produced from shales or other very low permeability formations, using multi-stage hydraulic fracturing in horizontal wells, as pioneered in the United States over the last few years. The interchangeable term "shale oil" is often used as well, by analogy with shale gas; but the term LTO reduces the risk of confusion with oil produced from "oil shales", that is, shales containing kerogen that needs to be heated up, or retorted, to be transformed into oil (which the *World Energy Outlook* designates as kerogen oil).

Just as shale gas is actually quite ordinary natural gas, indistinguishable from conventional gas, so LTO is a normal type of crude oil, though often a light crude.[3] So far, it has been distinguished by the specific production technology involved. However this technology is now more and more applied as well in some low permeability conventional oil reservoirs. And conversely, some LTO (or shale gas, for that matter) can be produced without using horizontal wells, as is the case, for example, in some tests in Argentina and Russia.

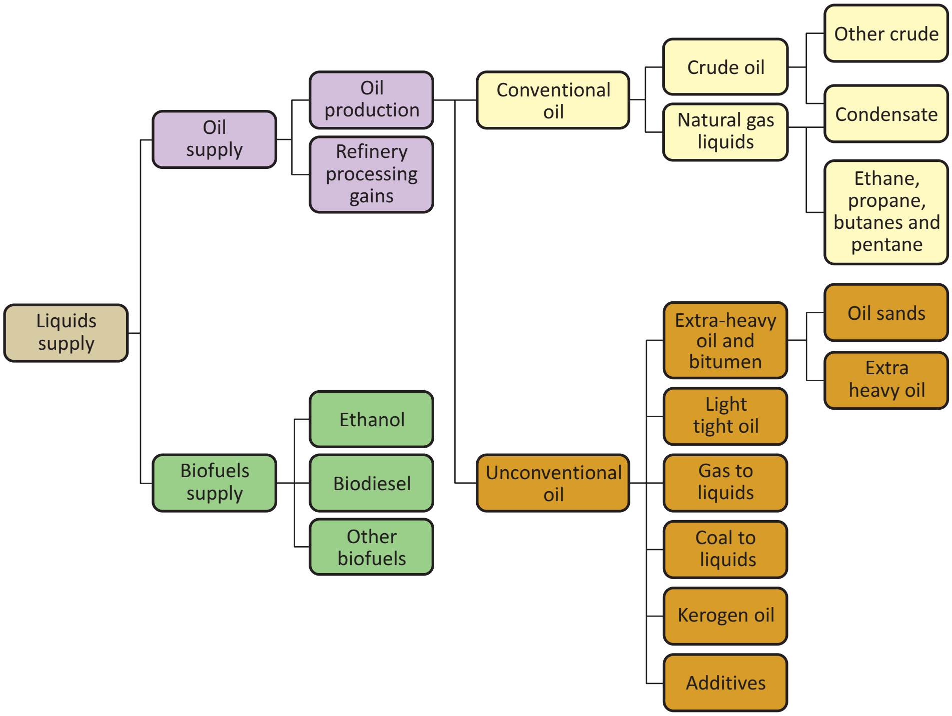
The remaining differentiating feature of LTO (and shale gas) is the geological setting: the oil or gas is trapped in "continuous" reservoirs, rock formations spreading over large geographical areas, in which the hydrocarbons are trapped by the nature of the rock itself rather than by the geometrical arrangement of the rock layers (as in conventional structural or stratigraphic traps). In that sense, these continuous plays can be called "unconventional", irrespective of the evolution of the technologies used.[4]

Although we distinguish between conventional and unconventional resources throughout this analysis, the division between the two, in practice, is an inexact and artificial one. There is no unique definition that allows us to differentiate between them; and, as is often said, what is unconventional today may be considered conventional tomorrow. In this *Outlook*, the breakdown shown in Figure 13.2 is used. Our classification of conventional oil includes crude oil and NGLs. The main components of unconventional supply are extra-heavy oil and bitumen (EHOB), which includes oil sands in our definition, and light tight oil (LTO) (Box 13.1). The extracted amounts of conventional and unconventional oil together make up "oil production". The term "oil supply" refers to production plus the volumetric processing gains that accrue during refining, as crude is turned into oil products, which are, on average, less dense (see Chapters 15 and 16). The term "liquids supply" refers to the sum of oil supply and biofuels.

3. Wherever possible, we consider as LTO only oil produced from plays where liquids represent more than 50% of the energy content, reserving the term unconventional wet gas for those with more gas; however there is clearly a continuum between the two and the data are not always publicly available to differentiate between them (and in fact, the notional boundary can also vary with time, as production proceeds).

4. Some reservoirs, sometimes called "hybrid", do not fall neatly into this categorisation. This is the case, for example, of the Bakken play, where one of the producing horizons is a low permeability carbonate, sandwiched between shale layers; so although it is an extended "continuous" play, it can also be said to have a conventional cap rock.

Figure 13.2 ▷ **Classification of liquid fuels**



Conventional oil

Resources

The *World Energy Outlook* (*WEO*) resources database and the projections for conventional oil (and gas) rely extensively on the work of the United States Geological Survey (USGS), in particular its World Petroleum Assessment, published in 2000, and subsequent updates.[5] The USGS assessment divides the resource base into three parts (Figure 13.3):

- Known oil, including both cumulative production and reserves in known reservoirs.
- Reserves growth, an estimate of how much oil may be produced from known reservoirs on top of the "known oil". As the name indicates, this is based on the observation that estimates of reserves (plus cumulative production) in known reservoirs tend to grow with time as knowledge of the reservoir and technology improves.[6]

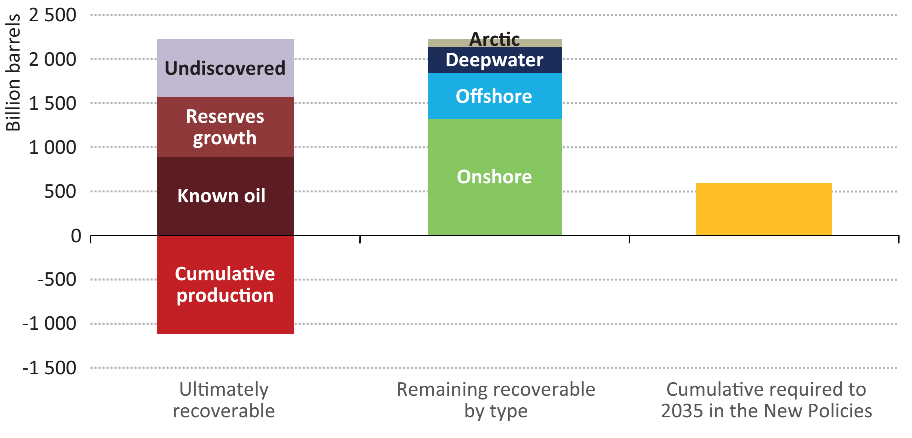
5. More information on the way that we incorporate USGS information into the IEA resources database is available in a methodological supplement at *www.worldenergyoutlook.org*.

6. For the 2000 assessment, reserves growth as a function of time after discovery was calibrated from observation in US fields, and this calibration then applied to the known worldwide reserves to obtain an estimate of worldwide reserves growth potential. The recent USGS (2012a) update uses a field-by-field assessment for the largest fields in the world. USGS geologists have repeatedly been able to demonstrate that their estimates of reserves growth are borne out by actual data (Klett and Schmoker, 2003).

- Undiscovered oil, a basin-by-basin estimate of how much more oil may be found, based on knowledge of petroleum geology.

The estimates of reserves growth, and particularly of undiscovered oil, are uncertain and therefore come with a probability distribution: they have a mean value and also values with a 5% probability and 95% probability (known as P05 and P95). Thus, USGS gives a range for total resources, which is useful for sensitivity studies; for example, the 2010 *Outlook* examined the impact of resources at the lower end of the range (IEA, 2010). In general, (and for all results shown in this *Outlook*) mean values are used for modelling purposes. Based on this approach, as of end-2012, we estimate that remaining recoverable resources of conventional crude oil stand at 2 200 billion barrels (Table 13.1). Of this sum, around 40% consists of known oil (excluding cumulative production),[7] a further 30% of reserves growth and 30% is as-yet undiscovered oil.

Figure 13.3 ▷ Ultimately recoverable conventional crude oil resources and cumulative production required in the New Policies Scenario



Notes: The ultimately recoverable conventional crude oil resources are as of January 2012, so the cumulative production required for the New Policies Scenario (for conventional crude only) covers the period 2012-2035. Known oil (in the USGS use of the term) includes also cumulative production.

Resources on this scale are more than sufficient to meet the projected demand for conventional crude oil to 2035, even given the uncertainties over the size of reserves growth and undiscovered oil. Cumulative production of conventional crude over the period 2013-2035 in the New Policies Scenario is 560 billion barrels, a figure that rises to 580 billion barrels in the Current Policies Scenario. If the P95 numbers for reserves growth and undiscovered oil are taken, *i.e.* the volumes at the lowest end of the range provided by USGS (associated with the greatest probability) and added to the figure for remaining known oil, then the remaining recoverable resource base is already 1 460 billion barrels.

7. Note that "known oil" in the USGS sense is actually smaller than reported proven reserves; some of this difference appears in "reserve growth"; see the section on Reserves, following, for further discussion.

Looking only at as-yet undiscovered oil, the projections to 2035 call for 170 billion barrels of cumulative new discoveries between now and 2035, comfortably below the 250 billion barrels that are the sum of USGS P95 estimates.[8]

A similar approach, based primarily on the same USGS publications, feeds into the *WEO* resources database of NGLs, allowing us to look at the total conventional resources shown in the first two columns of Table 13.1. However, the projections of future NGLs production are driven by gas production (see Chapter 3) rather than by NGLs resources.

Technically versus economically recoverable resources

The USGS is careful to say that their estimates are for technically recoverable resources, not necessarily resources that are economically recoverable. For example, the offshore Arctic contains a significant amount of undiscovered oil; but even if some offshore Arctic resource developments appear to be viable at current oil prices (as exemplified by the exploration carried out by Exxon/Rosneft in the Kara Sea), in all likelihood, exploitation of most of the rest will depend on gradual infrastructure development and technological progress before it becomes economically possible at current oil prices.

On the other hand, the methodology used by USGS, which is largely based on drawing analogies with already producing reservoirs, implies that a large fraction of the volumes categorised as undiscovered oil and reserves growth may be recoverable without significant changes in price and technology. In any case, if oil prices rise with time, it is not because there is a shortage of lower cost oil, but rather because the industry's capacity to increase oil production at the same pace as demand growth is limited (by national policies, in some countries, and by shortage of skilled people overall). High prices are therefore required to moderate the growth in demand and bring it into equilibrium with the rate of increase of supply.

One could also argue that the amount of technically, but not economically, recoverable oil in the earth's crust is much larger than estimated by USGS.[9] Indeed, if the cost of doing so were not prohibitive, one could in principle recover close to 100% of the oil-in-place using deep mining technologies, instead of wells (the deepest exploited gold mine in the world reaches a depth of 4 000 metres, comparable to most oil reservoirs). As discussed in the section on enhanced oil recovery, there is scope for ultimately recoverable resources to exceed the USGS numbers.

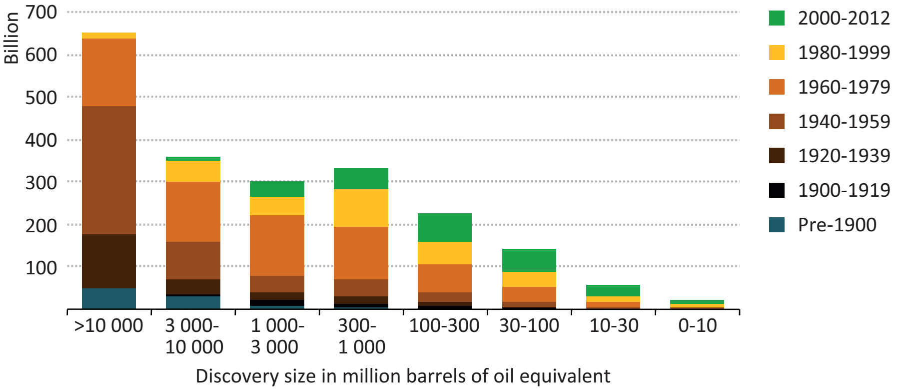
Undiscovered field size distributions

A factor that pushes costs up is the expected distribution of undiscovered field sizes. A review of the discovery dates and size of fields making up today's conventional crude reserves reveals that most of the world's large fields were discovered some time ago. Discoveries over the last ten to twenty years have typically been fields in the 30 million to 3 000 million barrels range (Figure 13.4).

8. Adding together different regional P95 estimates produces a sum with a probability considerably greater than 95%.

9. We focus here on recovery factors; another reason is that the USGS studies do not yet cover all potential oil and gas provinces.

Figure 13.4 ▷ **Conventional crude oil resources by field size and year of discovery**

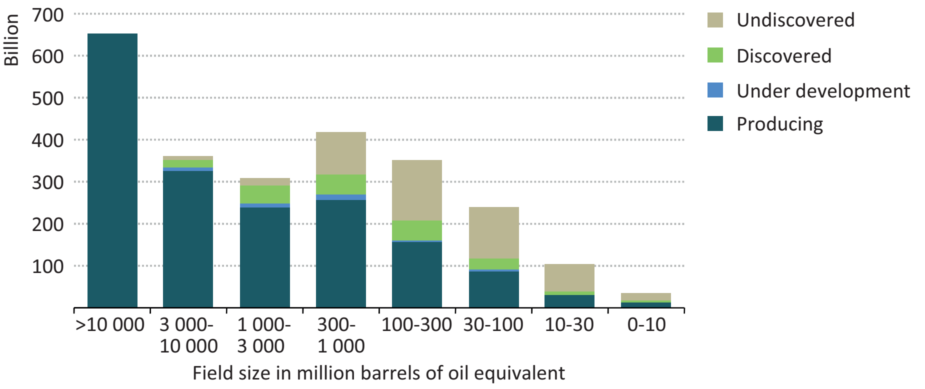


Notes: Includes cumulative production to date. Use of a different database and methodology makes the total not directly comparable with other resource numbers given in this chapter.

Sources: IEA analysis; Rystad Energy AS.

If the picture is extended to include the estimated size distribution of undiscovered fields, the trend towards smaller discoveries is likely to continue: the size distribution of undiscovered fields is concentrated around fields holding between 10 million and 1 000 million barrels (Figure 13.5).

Figure 13.5 ▷ **Estimated conventional crude oil resources by field size***

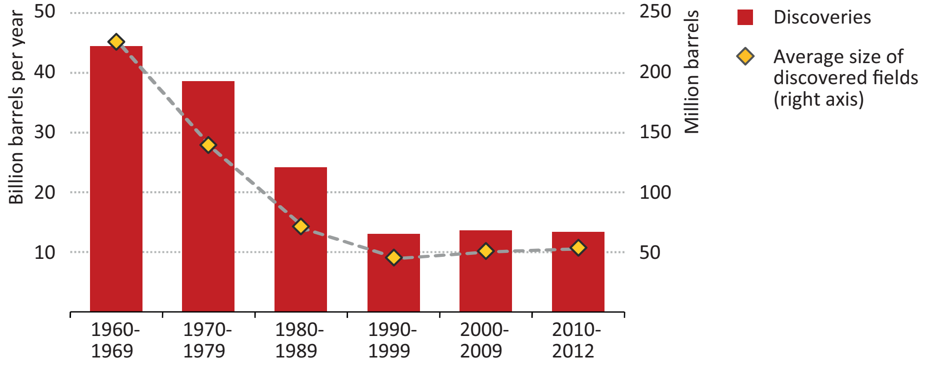


*The total amount of undiscovered resources in this figure does not match with the estimates of USGS, due to different methodologies. USGS has not published a comprehensive set of recent updates to its undiscovered field sizes distribution, but the one contained in the 2000 assessment shows somewhat larger sizes than the field database used here. Notes: It is often argued in the literature that the distribution of field size in the earth should be log normal. The distribution shown in the figure is not (a log-normal distribution cannot have the trough seen in the first three bars). However, there is no theoretical argument for a log-normal distribution: it is more an approximate empirical observation. The actual distribution can deviate from log-normal, due to the effect of a small number of very large fields (and data gaps may also skew the distribution).

Sources: IEA analysis; Rystad Energy AS.

A closer look at trends in discovery rates and discovered field size over the last fifty years shows that the rapid decline observed since the 1960s has been arrested (Figure 13.6). Both volumes discovered per year and the average field size of discoveries has stabilised in the last ten years, a development that is in large part attributable to higher oil prices and improvements in technology that opened-up deepwater and pre-salt provinces.

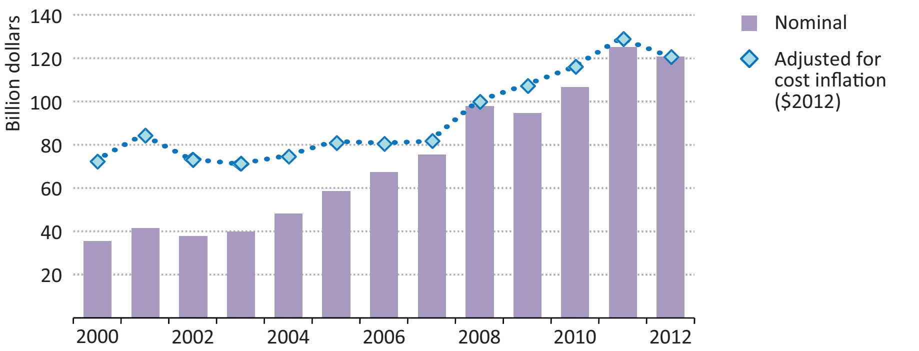
Figure 13.6 ▻ Observed discovery rates and average discovery size



Sources: IEA analysis; Rystad Energy AS.

Indeed, discovery rates depend not just on geology but also on exploration spending, which has picked up significantly over the last five years in response to increasing oil prices, after remaining fairly flat in the early part of the 2000's (Figure 13.7). Adjusted for cost inflation in the industry (assuming exploration costs followed the trend given by the IEA Upstream Cost Index, which reflects costs in the entire upstream sector), the pick-up in activity became significant only after 2007. Up to then, tight service industry capacity, after a decade of relatively low exploration levels, resulted in increases in the costs of services and materials, offsetting the growth in spending (increased exploration in higher cost areas, such as deepwater, also contributed).

Figure 13.7 ▻ Global exploration spending, 2000-2012



Notes: The graph shows total capital expenditure on exploration, including conventional and unconventional oil and gas; one cannot meaningfully separate exploration spend by categories.

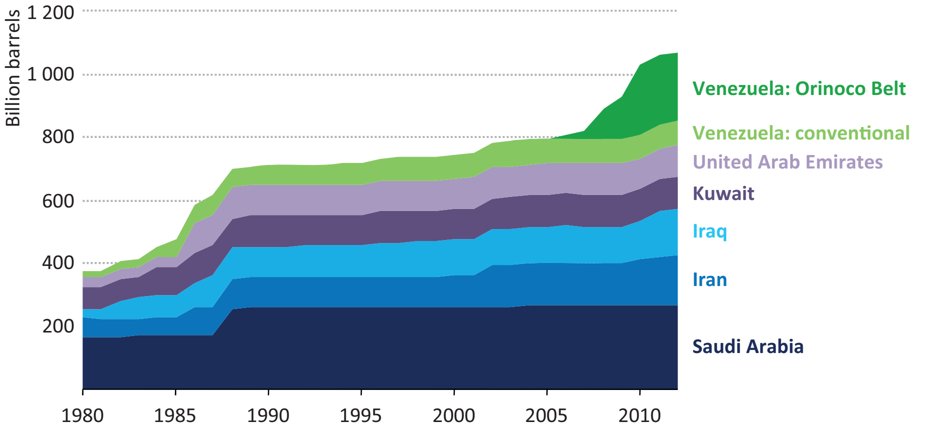
Sources: IEA analysis; Rystad Energy AS.

13

Reserves

Once resources have been discovered and positively appraised, they become reserves. Depending on the degree of certainty of their value and the confidence in their development, reserves are further classified as Proven (1P), Probable (2P) or Possible (3P) (Box 13.2). One often sees the statement that proven reserves have increased substantially over the last twenty years, indicating that the industry is proving up reserves faster than it is producing. However a more detailed look at the evolution of reserves (as published by BP [2013] or the *Oil & Gas Journal* [2012]) reveals that a large part of the increases observed is linked either to revisions in OPEC countries or to the incorporation of unconventional reserves that were previously not included (Figure 13.8).

Figure 13.8 ▷ Evolution of published proven reserves for selected OPEC countries



Source: BP (2013).

In relation to some of the revisions by OPEC countries, the published "proven" reserves numbers include values that may not really be proven in the strict sense of the Petroleum Resources Management System (PRMS) (Box 13.2). Several countries have reported large increases in proven reserves that do not seem to be based on field activities that would produce changes in the probability of future production from these fields, beyond new geological assessments (this was in part due to OPEC quotas having been linked to reserves for a number of years). The issue is not that the oil may not be actually there; it is more that the degree of maturity of the corresponding projects is probably more representative of 2P reserves than of 1P.[10]

10. Indeed our special study of Iraq in *WEO-2012* confirmed that, at least for Iraq, the reported reserves correspond to oil that is clearly there, as demonstrated by the plateau production commitments taken by large international companies with access to the detailed geological information about the fields. Given what is known about the regional geology, the reserves reported by Iran, Saudi Arabia, Kuwait and the United Arab Emirates are reasonable, in a 2P sense, compared to those of Iraq.

Box 13.2 ▷ Oil resources and reserves under different classification systems

The USGS categorisation of resources is less widely known than the designations used under the Petroleum Resources Management System (PRMS) (PRMS, 2007), which is also encapsulated in the United Nations framework classification that covers all energy and mineral types (UNECE, 2009). In the PRMS classification, reserves come in three categories, with decreasing probability of being produced:

- Proven reserves (or 1P), the amount of oil that has a more than 90% probability of being produced. This implies not only near certainty of the geological presence of the oil and of the ability to produce it at current oil prices, but also a high probability of implementation of an actual production project. For listed companies, this is usually taken to mean that the project has been "sanctioned", *i.e*. a final investment decision has been taken.
- Probable reserves (or 2P), the amount of oil that has a more than 50% probability of being produced as part of projects that have a high probability of being implemented. The uncertainty can be in the geology, the possible production rates or the economics of producing that part of the resources. 2P reserves are usually quoted as including 1P reserves (and can also be referred to as "proven + probable").
- Possible reserves (or 3P), the amount of oil that has a more than 10% probability of being produced. The uncertainty usually reflects the availability of only limited information on the geology and the ability to produce.

The PRMS classification also includes a category of Contingent Resources, those resources that are estimated to be technically, but not yet economically, recoverable or for which there is no likely project yet. It can be the case that the production project is down the priority list of the company with the production rights, even though the economics are sound: any oil producer will maintain a portfolio of potential projects beyond those that their capital budget allows them to pursue. Such cases should properly be counted as contingent resources, although in practice they are often included in reserves. There are also prospective resources, which have yet to be discovered.

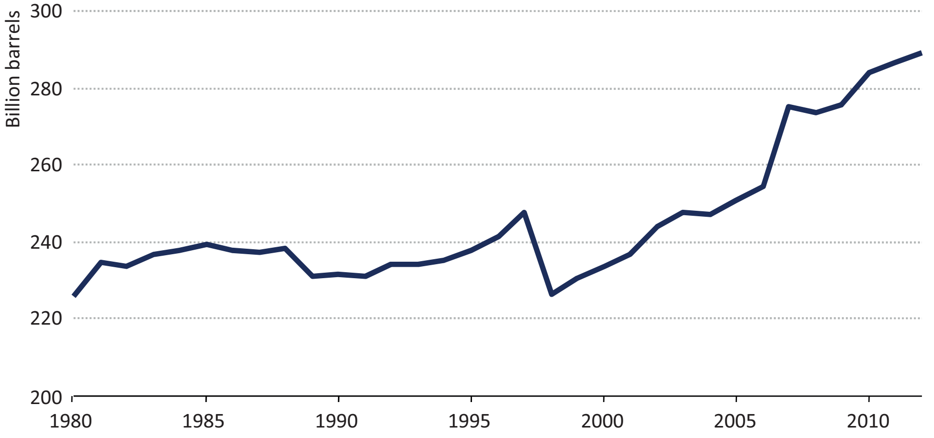
There is no exact fit between the definitions used by USGS and the PRMS classifications, but USGS "known oil" could be understood to correspond broadly to the figure for proven reserves (1P) plus already produced; the USGS "mean value" for reserves growth to the difference between proven reserves (1P) and probable reserves (2P)[11]; and USGS "undiscovered oil" being equivalent to prospective resources.

When testing the notion that the industry is proving up reserves faster than it is producing, it is worth looking specifically at non-OPEC conventional reserves, rather than the global totals (Figure 13.9). After a long period of stagnation and a drop in 1998, due to the very

11. With the addition of some probable contingent resources (2C) as well to reflect the fact that the USGS figure is for technically, but not necessarily economically, recoverable oil.

low oil price that year, there has been a clear ramp-up in proven reserves since 2002, as higher oil prices moved reserves from a non-commercial to a commercial category and stimulated an increase in appraisal activities.

Figure 13.9 ▷ Non-OPEC conventional crude oil proven reserves, 1980-2012



Source: BP (2013).

Overall, nearly 80% of the world's proven-plus-probable reserves, including both conventional and unconventional oil, are controlled by national oil companies (NOCs) (Box 13.3) or their host governments (Figure 13.10). NOCs control not only by far the largest portion of reserves, but also those with the lowest average development and production costs (although NOC assets are not exclusively low-cost, as shown, for example, by Petrobras' deepwater reserves, discussed in Chapter 11). Remaining reserves are shared between the Majors (7%) and Independents (13%). The share of the Independents is boosted by major Russian non-state reserve-holders (such as Lukoil and SurgutNefteGaz) and by companies that have stakes in the Canadian oil sands. It also includes their equity ownership in upstream projects where the other companies may hold the operatorship: for this reason, the operating share of the Majors is larger than their share of the ownership of reserves. While almost all of the reserves held by NOCs consist of conventional oil (except for PDVSA, the Venezuelan national oil company), unconventional oil reserves play a larger role for the privately-owned companies. Around 40% of the reserves held by Independents consist of unconventional oil. The Majors have a diversified reserve base, with their share of conventional oil being below 80%, extra-heavy oil and oil sands covering 15% and other unconventional oil making up the rest, mainly tight oil and liquids from shale gas production.

The predominance of NOCs in resource ownership does not have uniform implications for markets or investment. NOCs focusing primarily on their national markets tend to have a strong hold on national resource development. While some are operating abroad or increasingly looking to do so, they tend to remain close to their host governments and are subject to political supervision as well as being driven by commercial motivation. Some of the governments in question have a policy of deliberately slowing the rate of depletion of their resources, in the interests both of short-term price management and conservation of resources for future generations. At the other end of the spectrum, there are NOCs that actively seek overseas assets, development opportunities and access to technology/knowledge transfer, which are subject to much the same competitive constraints and pressures as private international companies. Particularly in cases where their capital has been opened up to private investors (with the state retaining a majority), these companies tend to behave more like privately-owned companies in their asset management and development strategies.

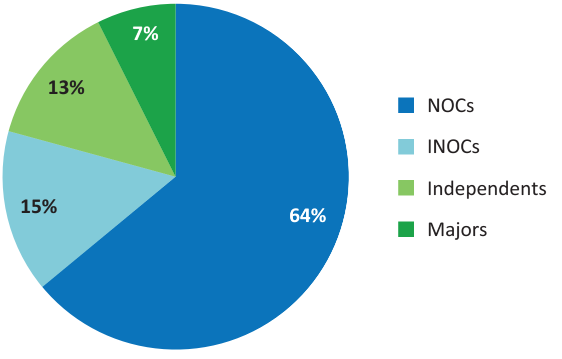
Box 13.3 ▹ Grouping oil and gas companies in the *WEO-2013* analysis

To analyse by company type the distribution of oil and gas resources and production and investment trends, upstream oil and gas companies are considered in four categories: two of these categories cover companies that are fully or majority-owned by national governments and the other two relate to privately-owned companies. Among the former, we distinguish between national oil companies (NOCs) that concentrate on domestic production and a second group of international national oil companies (INOCs) that have both domestic and significant international operations. Among the privately-owned companies, we distinguish seven large international oil companies (referred to as the "Majors") from the rest (referred to as "Independents").

These categories include:

- NOCs include more than 100 companies that are majority- or fully-owned by their national governments and concentrate their operations on domestic territory. The largest of these are in the Middle East (notably Saudi Aramco, National Iranian Oil Company, Qatar Petroleum), but there are also companies in this category in Russia and the Caspian (Rosneft, Uzbekneftegaz) and Latin America (PDVSA).
- INOCs are likewise majority- or fully-owned by their national governments, but have significant international operations alongside their domestic holdings. Around 25 companies are included in this category, such as Statoil, PetroChina, Sinopec, CNOOC, Petrobras, Petronas, ONGC (India) or PTTEP (Thailand).
- Among the privately-owned companies, the "Majors" are BP, Chevron, ExxonMobil, Shell, Total, ConocoPhillips and Eni.
- "Independents" covers all majority privately-owned companies, except the Majors. This category encompasses a wide range of companies active in conventional and unconventional oil and gas, from Russian companies, like Lukoil, to a large number of North American players, like Devon, Apache and Hess, to diversified companies with upstream activities, such as Mitsubishi Corp. and GDF Suez.

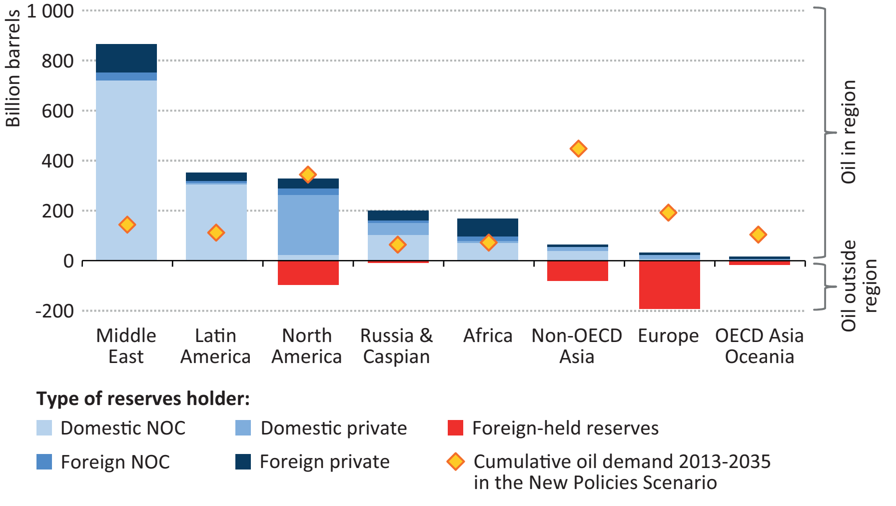
Figure 13.10 ▷ Ownership of 2P ("proven-plus-probable") oil reserves by type of company, 2012



Sources: IEA analysis; Rystad Energy AS.

The activities of the main privately-owned international oil companies and other large private integrated companies are more geared towards shareholders' interests and market signals. They have a broad portfolio of projects, which gives them scope to optimise their operations according to investment conditions. Smaller independent companies are concentrated in North America; their business model does not always comprise the full life-cycle but rather has them specialise on a specific asset type or geographical location.

Figure 13.11 ▷ Distribution of proven-plus-probable reserves by region and type of company, 2012



Note: The sum of foreign reserves held (in red) is equal in aggregate to the amount of assets held in home regions by "foreign private" companies and "foreign NOCs" (two darker shades of blue).

Source: IEA analysis based on AS Rystad Energy.

Considering the location of the assets held by NOCs and privately-owned companies, respectively, the majority of reserves in the Middle East and Latin America are held by the domestic NOCs, whereas in North America (with the exception of Mexico) this role is taken on by private companies (Figure 13.11). In Russia, there are still some strong domestic, privately-owned companies, but the trend over the last few years has been towards consolidation under NOCs: Rosneft's acquisition of TNK-BP in 2012 means that the enlarged company accounts for 4.1 million barrels per day (mb/d) of Russian oil and condensate production (as of the first half of 2013).[12] Together with Gazprom, Gazpromneft and other smaller players, the share of majority state-owned companies in Russian output has risen to more than half. Companies with their headquarters in the Atlantic basin, in Europe and North America, are the largest reserve-holders outside their home regions, having a legacy of foreign assets. Although Asian companies are currently among the most acquisitive internationally, their overseas holdings remain relatively small, in particular by comparison with the extent of their anticipated oil demand.

Development of oil reserves by scenario

A key question for reserve-holders is the expected future trajectory of oil demand and the way that prices and policy interventions by governments may affect this trajectory. As examined in Chapter 15, related uncertainties are diverse. High oil prices create incentives to substitute other fuels for oil, where possible. There is huge latent demand for mobility in many emerging economies, yet this is also accompanied, in many cases in the projections, by a large rise in dependence on oil imports, especially in many parts of Asia: this is likely to generate a policy response favouring alternatives to oil. There is also increasing public pressure in many countries for actions to reduce traffic congestion and local pollution. Climate policy comes into the picture too: as described in Chapter 2, in the New Policies Scenario the world misses, by some distance, the agreed target to limit the long-term increase in average global temperatures to 2 °C. It is therefore reasonable for companies to expect action by policymakers to address these issues through additional measures to increase fuel efficiency, reduce emissions targets from passenger vehicles and support alternative fuels.

Our 450 Scenario gives insights into the implications for oil of a concerted policy push in these areas, making allowance for technological advances in the transportation sector. Compared with the New Policies Scenario, where oil demand rises (albeit at a slowing pace) to more than 101 mb/d by 2035, the 450 Scenario sees oil demand peaking in 2020 at around 91 mb/d, before a gradual decline to 78 mb/d in 2035 leaves oil demand in 2035 some 23 mb/d lower than in the New Policies Scenario. This oil demand trajectory would have wide-ranging implications for the oil sector, but the difference in terms of the volume of oil resources that need to be developed over the period to 2035 is perhaps less striking. *WEO-2012* calculated that, if the world is to reach the 2 °C target, no more than one-third

12. Combined Rosneft - TNK-BP plus its equity share of Slavneft production.

of proven fossil fuel reserves can be consumed prior to 2050, unless carbon capture and storage technology is widely deployed. This finding, which was developed in the *WEO 2013 Special Report Redrawing the Energy-Climate Map*, is applicable to all fossil fuels, including coal – which is the hardest hit by more stringent climate policy. Looking solely at oil, an amount equivalent to around 45% of current proven reserves would be developed in the 450 Scenario, only some seven percentage points less than the equivalent share of oil reserves developed in the Current Policies Scenario. This suggests that the likelihood of leaving upstream assets "stranded" because of policy uncertainty is limited (Box 13.4). The scope for stranded assets in the refinery and distribution sectors is, though, much greater.[13]

Box 13.4 ▻ The risk of "stranded assets" in the upstream oil sector

Stranded assets, in the context of this discussion, are those investments which are made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return, as a result of changes in the market and regulatory environment. The implications for upstream resource-holders can best be understood by looking at three different categories of oil resources. The first is reserves that are currently being produced, representing investments that have already been made. A second category is resources that are proven but not-yet-developed; in this case, part of the investment (the exploration costs) has already been incurred, but the development costs, typically 85% of total capital investment, are yet to come. The third category is reserves growth and resources that are yet-to-be-found; no investment has been made in this category.

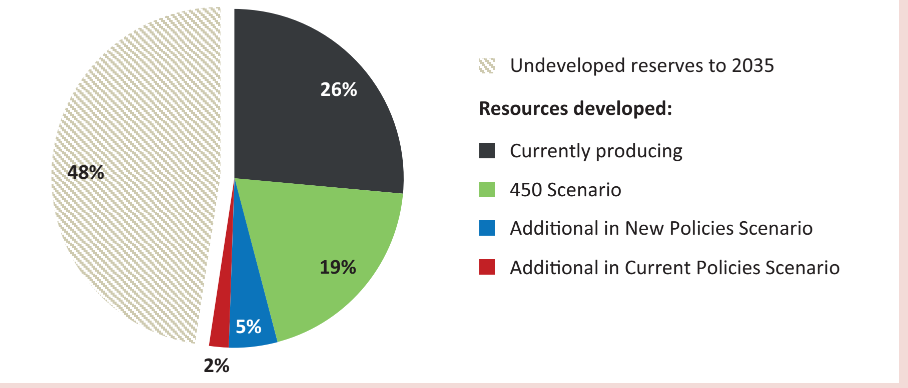
The first category will produce without additional investment and, because the rate of natural decline exceeds any conceivable rate of demand drop due to climate policies, this category is unlikely to be stranded (although the return on investment may drop, due to changes in the oil price). For the other categories, major capital spending lies in the future and can be aligned with changing perceptions of demand. Only the exploration costs of the proven but not-yet-developed reserves (the second category) risk being stranded.

Reserves that are not yet developed nonetheless contribute to the valuation of publicly-listed companies and it has been argued that they may be over-valued in the event of major changes in government energy policies. This view risks overstating the differences for oil and gas reserve-holders between the three scenarios as well as the extent to which today's company valuations reflect an expectation of a return on new investment in exploitation of reserves that may, in certain circumstances, not be

13. The higher risks in the downstream are linked to the fact that refinery investments are large, capital-intensive and long-term and need high utilisation rates to make an economic return. As examined in Chapter 16, there is already a risk in the New Policies Scenario that refinery capacity additions run ahead of the projected demand for refined products. If there were to be an overall decline in oil demand (as in the 450 Scenario) rather than just a fall in OECD countries (as in the New Policies Scenario), then the likelihood of assets being stranded would grow considerably.

developed before 2035 (Figure 13.12). In addition, most of these undeveloped reserves are either unlicensed or are held by national oil companies that are not publicly listed).[14]

Figure 13.12 ▻ Oil resources that are developed by scenario as a percentage of proven reserves



Notes: In practice, the oil produced in each scenario comes not only from proven reserves, but also from reserves growth (increases in reserves in known fields) and from as-yet-undiscovered resources. The figures for proven reserves exclude NGLs.

Enabling technologies: focus on enhanced oil recovery

Technological progress has always played a key role in the upstream oil and gas industry. It rarely takes the form of sudden breakthroughs (even the shale gas and light tight oil revolutions are built on the gradual evolution of technologies that had been used for many years), but rather on constant, gradual, progress that always pushes the boundaries determining which resources can be produced and at what prices. Periods of high prices encourage the industry to push the envelope on the most technically ambitious projects in new frontiers, while periods of low prices push innovations on technologies or processes that help contain costs. For conventional oil, two sets of technologies are having and will continue to have a significant impact on available resources: deepwater and enhanced oil recovery (EOR). Deepwater developments are covered in detail in Chapter 11 as part of the special focus on Brazil; here the focus is on the prospects for EOR.

EOR can be defined as the set of technologies that permits production of a greater share of the oil that remains after primary and secondary recovery (Box 13.5). The main classes of EOR technologies are:

- The use of steam to heat the oil. This is usually used for heavy oil reservoirs. Heat reduces the viscosity of the oil, making it easier to move.

14. Under the PRMS system of classification (Box 13.2) oil cannot be classified as reserves unless it is licensed for production, but some of the reported reserves, for example for Canadian oil sands, do not follow PRMS.

- Miscible gas injection, either with hydrocarbon gas or carbon-dioxide (CO_2). Miscible means that the gas mixes with or dissolves into the oil, reducing its viscosity and increasing its susceptibility to being pushed by water. Immiscible gas injection (with nitrogen, CO_2 or hydrocarbon gas that does not dissolve in the oil) is sometimes also considered as an EOR technique, though it is more a form of secondary recovery. Water-alternating-gas (WAG) injection, in which a water injection cycle is followed by a gas-injection cycle, can also be considered either a secondary or an EOR technique. It is practiced in Norway (and planned for the Santos basin in Brazil, see Chapter 11). WAG and immiscible gas injection have not been included in the EOR numbers.
- Chemical flooding, in which water soluble polymers and/or surfactants are added to the injected water. Polymer flood has long been used in China and to a lesser extent in Russia, Canada and the United States. The higher viscosity of polymer-loaded water allows it to push more oil out of the pores (and also means fewer oil zones are being by-passed). More recently a combination of polymers and surfactants (which reduce the interfacial tension with water) has gained in popularity in the Alkaline Surfactant Polymer (ASP) technique.
- Microbial EOR, in which micro-organisms are injected in the reservoir. They can be used to break-down heavy oil into lighter components that flow more easily, or to produce in-situ some biopolymers or bio-surfactants that help mobilise more oil. There have been numerous pilot trials of microbial EOR over the last 30 years but, so far, no large-scale application.
- Combustion flooding. This involves in-situ burning of some of the oil to generate both heat and gases that help the rest of the oil to flow. Although used commercially for a long time in some reservoirs, it is difficult to control efficiently.
- The use of vibrations (either from the surface, or downhole, using a variety of "shakers" or sound sources). This is a controversial technique, as its mechanisms are poorly understood, but positive effects have been reported in some pilot tests.

Another approach is the use of tailored water in injection schemes. As first shown in the late 1990s in the Ekofisk reservoir in the Norwegian sector of the North Sea, the amount and type of salts contained in the injection water can affect the microscopic recovery rate significantly, because salts can interact with the reservoir minerals, helping to "un-stick" oil from the surrounding rock (Austad, 2013). Tuning these salts to the reservoir properties has recently gained popularity, particularly under the name "low salinity water injection", and replacing by fresh water the sea-water which has traditionally been used has given positive results in a number of regions. In a sense, this is an EOR technique, as it affects recovery at the pore level, but as the technology is not really different from normal water injection, changing only the source of water supply, it is generally not classified as EOR.

Box 13.5 ▷ Recovery rates and the case for EOR

After primary recovery (where oil is produced due to the natural pressure in the reservoir) and secondary recovery (where pressure is provided by injecting water or, in some cases, gas), around two-thirds of the oil originally in place in a conventional oil reservoir is typically left unproduced. For this reason, there has long been a strong interest in techniques for producing a greater share of the oil, *i.e*. increasing recovery rates. These recovery rates vary greatly from one reservoir to the next; one-third represents a rough global average. Uncertainty about the extent of recovery is inevitable, given that the amount of oil initially in place is not known exactly, and the operator does not know how much oil will be produced from a reservoir until the reservoir is abandoned. Even for individual fields, recovery rates are only estimates, based on oil companies' (usually proprietary) models of their reservoirs and future output. As such, it is not easy to track whether the industry is making progress in increasing recovery rates. The clearest data comes from the Norway Petroleum Directorate (NPD), which shows that in 1995, the expected average recovery for Norwegian fields, after planned shutdown, was 40%. By 2012, it had risen to 46% and NPD is planning to increase it to 50% in the future (NPD, 2013).

There are two mechanisms that contribute to low recovery rates. The first can be called "by-passed oil": this is oil in parts of the reservoir which has not been moved towards the wells. This can occur because that part of the reservoir is fully or partially unconnected to the rest, because of faults or other geological features: in these cases, the reservoir is said to be compartmentalised. Another possibility is that water may have moved towards the well, by-passing some of the oil, which was thus never "pushed" by the water. Trying to produce such by-passed oil calls on technologies often called "improved oil recovery" (IOR), which involve identification of the zones where oil is left (for example with 4D seismic, using time-lapse seismic surveys that allow fluid movements in the reservoir to be tracked) and targeting them with new wells (in-fill drilling) or laterals drilled from existing boreholes. Another approach involves changing the water (or gas) injection patterns to re-route water towards the by-passed parts of the reservoir. As shown particularly in the Norwegian continental shelf, systematic application of such optimised reservoir management technologies can boost average recovery rates close to 50%.

The second reason for incomplete recovery involves the physics of flow in rocks at the microscopic (or pore) level. The oil is contained in small pores in the rock of a size typically in the tens to hundreds of microns. Some of the pores may be connected to others only by very tiny pore-throats, through which oil does not flow well, if at all. Some of the oil may stick to the rock minerals on the walls of the pores. Even on the small scale of pores, water can by-pass small oil globules, flowing around them. As a result of these various mechanisms, not all of the oil contained in the pores is produced: there is an amount of oil (called the "irreducible oil saturation") that always remains. Further reducing the amount of oil left in the pores calls for EOR technologies.

Potential of EOR

Most of the information available about the potential of EOR relates to the United States. A study by INTEK for the US Energy Information Administration (EIA) (Mohan, *et al.*, 2011) gives estimates of more than 50 billion barrels recoverable in the United States from the various known EOR technologies, based on field-by-field studies; about half that amount is thought to be economical at oil prices of $80/barrel. CO_2 injection alone is thought to be able to bring 40 billion barrels of additional recovery, chemical EOR around 15 billion barrels, and steam techniques close to 10 billion barrels (some fields are suitable for more than one technology, so the sum of these numbers is more than the total estimated potential). CO_2 injection has attracted attention because of its potential to contribute to underground storage of carbon. Various studies give different estimates, for example, the United States National Energy Technology Laboratory has estimated that 137 billion barrels could be recoverable from CO_2 EOR in the United States (Kuuskraa, van Leeuwen and Wallace, 2011), of which 67 billion barrels could be recovered economically at oil prices of $85/barrel.

The USGS has looked at a few large fields in the Permian Basin and in California, as part of their assessment of potential reserves growth (USGS, 2012b, 2012c and 2012d) and estimates that, for the 37 fields assessed that contain 38 billion barrels of known oil, an additional 12 billion barrels could be technically recovered (the assessment is not limited to EOR technologies, but in these very mature fields, most of the additional recovery would come from EOR). Scaled-up to the more than 200 billion barrels of known oil in the United States, this could yield 65 billion barrels.

A more top-down approach starts from the estimated conventional crude oil-in-place in the United States, on the order of 1 000 billion barrels. With an average recovery factor, without EOR, of 35%, this gives recoverable resources of 350 billion barrels, of which almost 200 billion have already been produced and 18 billion are proven reserves (the rest being reserves growth and undiscovered). Using a conservative estimate of 10% for the additional average recovery possible by systematic application of EOR technologies gives 100 billion barrels of potential additional oil. This is broadly in line with the field-by-field, bottom-up, estimates.

Worldwide, the information about potential for EOR is more limited. A study of 54 basins for their potential for CO_2 EOR gave an estimate of 470 billion barrels (Godec, 2011). A study for the IEA comes up with a similar number (430 billion barrels), provided one assumes the use of technologies that maximise CO_2 storage, which are cost-effective only in the presence of a carbon price (IEA, forthcoming). Using a top-down approach, if a 10% improvement in recovery rate is applied to the estimated global amount of oil-in-place of 10 000 billion barrels, this yields an EOR potential of some 1 000 billion barrels, four times the reserves of Saudi Arabia. Not all of this EOR potential is additional to our other estimates of ultimately recoverable resources of conventional oil. Indeed the USGS reserves growth numbers do include the application of EOR technologies to large fields in the world. We estimate, however, that systematic application of available EOR technologies throughout the world, including CO_2 EOR+ (Box 13.6), would unlock at least 300 billion barrels on top of the URR values.

Box 13.6 ▷ CO_2 enhanced oil recovery for carbon capture and storage

CO_2 enhanced oil recovery (CO_2 EOR) has long been practised because CO_2 has appropriate properties for enhancing oil recovery: under the right conditions of temperature and pressure, it dissolves in crude oil, increasing the mobility of the oil. Historically, most projects used naturally occurring CO_2 found in geological reservoirs similar to those of natural gas (the two are often found together, with CO_2 concentrations running from a fraction of 1% up to nearly 100%).

During a CO_2 EOR operation, CO_2 is injected into the reservoir, mobilises the oil, and is back-produced, together with the produced oil. At the surface, it is separated from the oil and re-injected. However a fraction of the CO_2 remains in the reservoir, typically about 0.3 tonnes per barrel of oil produced, and this needs to be compensated for by fresh CO_2 supply. Because CO_2 is a cost to the operator of the field, the company will try to optimise the process so that the amount of CO_2 remaining in the reservoir is as small as possible.

As this CO_2 remaining in the reservoir is effectively locked there for a very long time (the oil reservoir is normally capped by a very impermeable layer that has prevented the oil from moving upwards for millions of years, so if the well is properly sealed, CO_2 should also be trapped in the reservoir), there is great interest in disposing of CO_2 produced by human activities by linking carbon capture and storage (CCS) with EOR.

If, because of incentives to capture carbon to slow down climate change, CO_2 is free to the operator or even available at negative cost, there would then be an incentive to leave as much CO_2 as possible in the reservoir; a CO_2 EOR process optimised in this way has been called "EOR+". Various studies have shown that as much as 0.6 to 0.9 tonnes of CO_2 could be stored per barrel of oil produced, while also increasing the amount of oil recovered. A study for the IEA (2014) shows that, while conventional CO_2 EOR has the potential to recover about 190 billion barrels worldwide (storing 60 gigatonnes [Gt] of CO_2), EOR+ could enable the recovery of 430 billion barrels, while storing up to 390 Gt of CO_2 (more than the emissions projected from the power sector between 2013 and 2035). This is one reason why the estimate for "additional EOR" potential resources goes beyond that included in the USGS estimates.

13

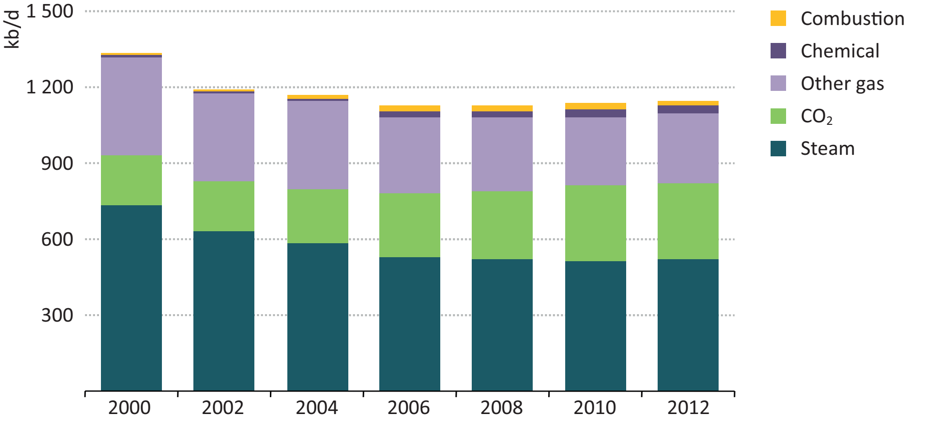
Current status of EOR

Most of the technologies classified as EOR have a long pedigree, having developed in the early 1980s, and a proven record of improving recovery rates. It therefore remains something of a puzzle that these techniques have not yet made a more substantial contribution to oil production.[15] Our estimate is that there are currently about 280 EOR

15. An initial challenge when analysing EOR around the world is the relative paucity of data. Outside the United States and Canada (the *Oil and Gas Journal* publishes every two years a list of active EOR projects and the corresponding production rates, with good coverage of activities in North America), EOR technologies are widely understood to be deployed in China, Russia and the Caspian region, among others, but the extent of their use is uncertain.

projects around the world, of which 75% are in North America, 10% in China and 15% in the rest of the world. Together, they produce some 1.3 mb/d of oil. The number of projects, the type of projects and the amount of oil produced by EOR has been relatively steady over the past ten years (Figure 13.13).

Figure 13.13 ▷ Estimated global EOR production by technology



Notes: The estimate excludes fields that we classify as unconventional, *e.g.* Canadian oil sands and Venezuelan Orinoco belt extra-heavy oil (steam-based technologies are extensively used for such unconventional reservoirs as the main recovery technique, as traditional primary and secondary recovery techniques are generally ineffective). The figure excludes China, because the data series for China are incomplete; China is estimated to produce about 170 kb/d: 150 kb/d from steam technologies and 20 kb/d with polymer injection.

Sources: *Oil & Gas Journal*; IEA databases and analysis.

Among the various EOR technologies, steam-assisted production has in the past given rise to the largest share of output, but this share is on the decrease, largely because the two large sets of steam projects that have dominated production for many years, in the San Joaquin Valley in California and Duri in Indonesia, are getting close to the end of their lives. One can expect the very large Wafra steam project being planned in the neutral zone between Kuwait and Saudi Arabia to offset this decline over time. Chemical EOR remains very small (outside China), but there are signs of growing interest. Shell, for example, is planning ASP pilot projects in Russia (at the Salym field, a joint-venture between Shell and GazpromNeft), in Oman with PDO, and in Malaysia with Petronas (at the Baram Delta and North Sabah fields – these would be the first offshore EOR projects in the world).

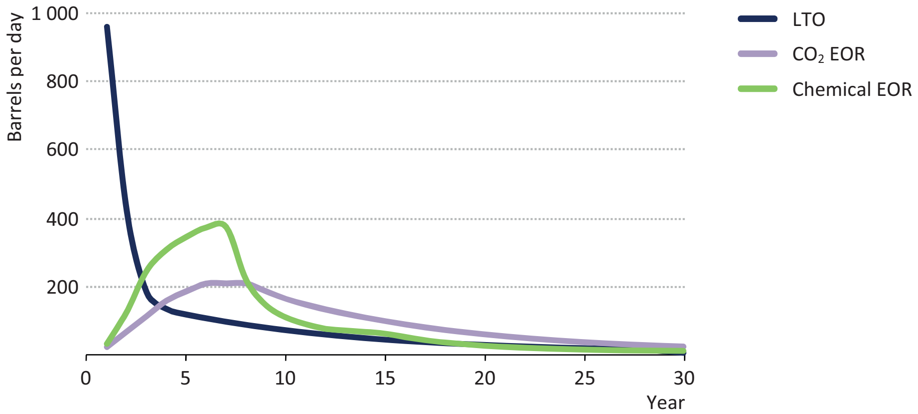
Oil production by CO_2 injection has seen a steady growth, gaining popularity, particularly, in West Texas and the Rocky Mountain states in the United States. Fed by CO_2 from natural reservoirs in the Rocky Mountains, the gas is piped over several hundred kilometres to the oil reservoirs. CO_2 injection technology is by now well established and has proven very effective, with recovery increased by as much as fifteen percentage points (*e.g.* from 35% to 50%). Further growth is limited at the moment by availability of CO_2, an ironic state of affairs, given the interest in coupling CO_2 EOR with CO_2 capture and storage (Box 13.6).

Interest in CO_2 EOR is growing around the world, though no full-scale project has materialised yet outside North America. Of particular significance is the interest in using such technology shown by Saudi Arabia and the United Arab Emirates as a 10% increase in recovery rate in fields in these two countries would represent a large amount of oil.

EOR economics, enablers and projections

The potential for oil production through EOR is large and the available information on costs – most of which relates to the United States – suggests that deploying various EOR technologies is profitable at current oil prices. Yet worldwide the level of EOR production remains relatively modest, contributing only 1.5% of total oil production, and it has already been overtaken by LTO production from the United States alone (despite the fact that the estimates for EOR potential in the United States are larger than the estimates for LTO resources). So why is the industry preferring to invest in LTO rather than EOR? The answer lies in a more detailed look at the risks, returns and staffing intensity.

Figure 13.14 ▷ Typical production profiles for LTO and EOR projects



Notes: This analysis compares "typical" production profiles for LTO, chemical EOR (ASP) and CO_2 EOR projects of similar total production. For EOR, the line represents additional production on top of the (generally declining) secondary recovery production level.

LTO costs are primarily the capital costs of drilling the wells (relatively high, due to the use of horizontal wells and multi-stage hydraulic fracturing) and securing the lease; operating costs are low. Production peaks in the first year and then declines rapidly, so the payback time is short, minimising long-term risks (Figure 13.14). On the contrary, an EOR project (*i.e.* the additional production that results from an investment in EOR techniques) tends to have moderate capital expenditure, but much higher operating costs, because of the costs of the chemicals (or gas in the case of gas injection) and of injection itself.[16] Even

16. Existing wells can sometimes be used for EOR projects. When new wells are needed they are usually low cost simple vertical wells. An exception is steam projects, where the upfront costs of the steam plant can be large, and expensive casing and pipes may be required to withstand the heat.

more importantly, the increase in oil production often takes months, if not years, to materialise, as the injected fluids need to flow the distance between the injecting well and the producing well before providing a significant production increase.

Our review of the economics of generic LTO and EOR projects in Table 13.2 suggests that all three types of projects are highly profitable. The LTO project has the shortest payback period and the highest internal rate of return. The chemical EOR project does well on a calculation of net present value (NPV), return-on-investment and on the lowest breakeven oil price. The CO_2 EOR project is the least attractive of the three, but still quite profitable; introducing a premium on CO_2 storage would bring its profitability to levels similar to the others. From this we can conclude that the LTO project is the preferred choice for an operator looking for quick returns on borrowed capital, while EOR is more for long-term investors looking for longer-term returns, such as NOCs. CO_2 EOR, with its longer project lifetime and possible value for CO_2 storage, could be particularly attractive.

Table 13.2 ▷ Comparative economics of LTO and EOR hypothetical projects

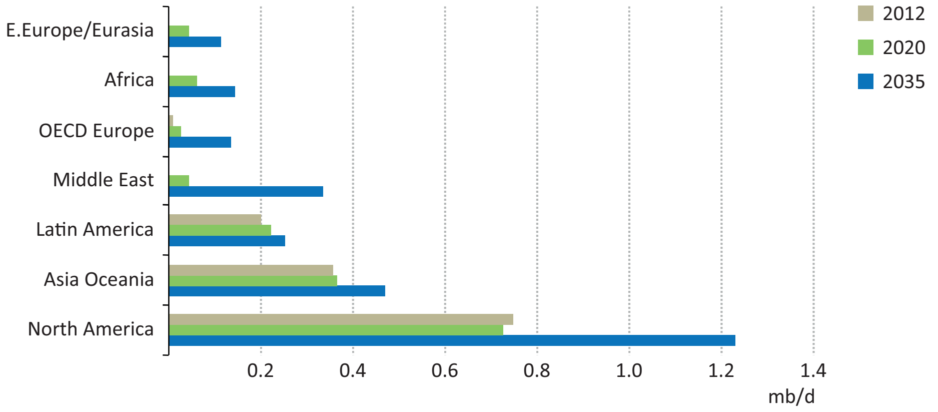
Input parameters	Unit	LTO	CO_2 EOR	Chemical EOR (ASP)
Capital expenditure	$/barrel	17	10	9
Operating costs	$/barrel	8	10	11
CO_2 / chemical costs	$/barrel	n.a.	10	10
Royalties and production taxes	$/barrel	22	22	22
Results pre-profit tax (at 15-year point)	**Unit**	**LTO**	**CO_2 EOR**	**Chemical EOR (ASP)**
NPV at 10% discount rate	$/barrel	17	10	18
Payback time	Years	2	7	4
Internal rate of return	%	53%	22%	35%
Breakeven oil price (NPV=0 at 15 years)	$/barrel	64	63	56
Return on investment	%	100%	99%	197%

Notes: Costs, royalties and taxes (and therefore economics) can vary greatly, depending on the actual project. Here it is assumed that the same royalties and taxes (taken from a typical LTO project) apply for all three. Slightly lower well-head oil prices for LTO are assumed, to reflect the fact that the liquid production often includes a significant share of NGLs, sold at a discount to West Texas Intermediate (WTI) oil. For this example, WTI prices are assumed to be $90/barrel at the start, gradually rising to $120/barrel over the 30-year lifetime of the project. Including allowance for risks, for example of lower future oil prices (typically reflected in an increased discount rate), would have little effect on the LTO project, but would reduce the attractiveness of the EOR projects.

But economics are not the only consideration and there is a range of other factors that limit the current and future use of EOR technologies. A key constraint is the availability of skilled staff; the various EOR technologies each require specialised knowledge that is often not widely available. The length of projects is another consideration: an EOR project generally starts with laboratory studies on cores to select the best technology, followed by one or several field pilots to apply the method to a small part of the field or a limited set of wells. The results of the pilot can take several years to be confirmed, delaying the moment at which the project is extended to an entire field (a process that may require construction of significant infrastructure to provide the chemicals, steam or CO_2). Even then, the results may also take a few years to materialise and could reveal unexpected problems, such as field heterogeneity, or reactions between injected fluids and minerals present in the rock. If the project is considered late in the life of the field, after years of standard secondary recovery, the remaining field life may not be sufficient to justify the project (EOR increases production over secondary recovery but, where production is declining rapidly, total production with EOR can still quickly decline to the point where oil production does not pay for operational expenses). For this reason, successful EOR projects need to be considered early in the life of a field, providing for maximum recovery from the start of the field development planning.

As part of this analysis, EOR has been treated as a distinct category of oil resources in the oil supply model – allowing projections for EOR to be tracked separately.[17] Although there are reasons to argue that EOR should gain in popularity at current and projected oil prices, in the projections we take account of the relatively limited EOR activity seen so far and remain conservative. In the projections, the volume of production attributable to EOR projects rises from 1.3 mb/d in 2012 to 2.7 mb/d in 2035 (Figure 13.15). Nonetheless, there remains significant upside potential for EOR production (not least for CO_2 EOR) – another reason to believe that a shortage of oil is not in sight. One of the determining factors will be developments in OPEC Middle East countries, where interest in maximising recovery is growing; a pilot project for steam-based EOR, using solar energy to generate the steam, has been built in Oman and similar projects are planned in the United Arab Emirates.

Figure 13.15 ▷ EOR production by selected regions in the New Policies Scenario



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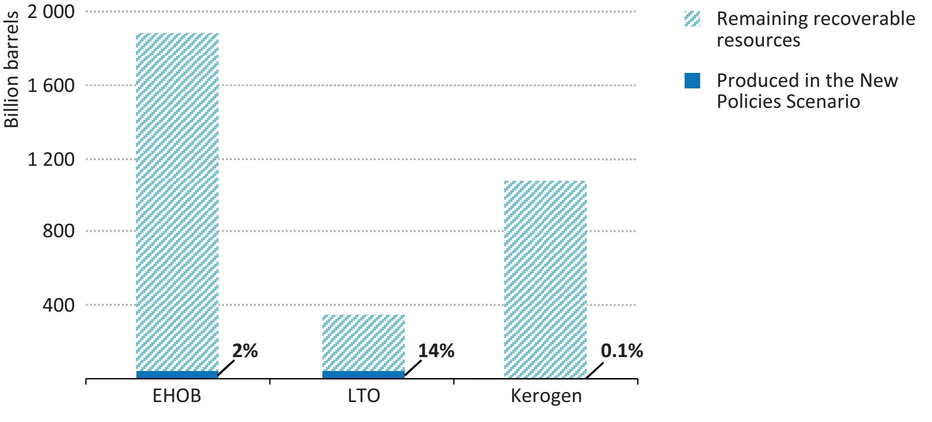
17. *WEO-2008* presented projections for EOR, but the supply module of WEM was revamped in 2010 without retaining separate treatment of EOR. This feature has been re-introduced this year.

Unconventional oil

Resources

Conventional crude oil has traditionally taken centre stage in any discussion about oil resources, as it has accounted for the lion's share of global production. In 1990, this share was more than 90%; in 2000 it was still 88%. Yet, since the turn of the century, it has declined more quickly; conventional crude oil made up only 80% of total production in 2012, with unconventional output (5.5%) and NGLs (14.5%) contributing the rest. The unconventional resource base, therefore, needs to be understood, even if, with the exception of light tight oil, the resources are so large, compared to the production projected to 2035, that they do not need to be studied in as much detail in the timescale of the *Outlook* (Figure 13.16).

Figure 13.16 ▷ Cumulative production versus remaining recoverable resources by type of unconventional oil in the New Policies Scenario



Note: Cumulative production is for the years 2013-2035.

Extra-heavy oil and bitumen

This category of unconventional oil (in *WEO* definitions) consists primarily of oil sands in Canada and the extra-heavy oil in Venezuela's Orinoco belt. Canadian oil sands oil-in-place has been estimated at 1 845 billion barrels (ERCB, 2013), of which 800 billion barrels might be recoverable (IEA, 2010). The Orinoco belt in Venezuela is estimated to contain about 1 360 billion barrels of oil-in-place (PDVSA, 2013), of which about 500 billion barrels might be recoverable (USGS, 2009). In addition to Canada and Venezuela, significant extra-heavy oil and bitumen resources are thought to exist in Russia and Kazakhstan, and modest amounts in Angola, Azerbaijan, China, Madagascar, the Middle East, the United Kingdom and the United States, for a global total of close to 1 900 billion barrels recoverable. Outside Canada and Venezuela, the projections to 2035 include some production only in Russia (Tatarstan) and China, where projects either already exist or are at an advanced planning stage.

Light tight oil

LTO is oil that has been generated from kerogen-rich shales over geological time but has either remained in the shale (instead of having migrated to a conventional reservoir) or has migrated to a nearby low-permeability rock. Because of the low permeability of the shale or host rock, it can generally be produced economically only by using special technologies, such as multi-stage hydraulic fracturing in horizontal wells. It is only in the last few years that commercial exploitation has reached a significant scale, with the rise of production in the Bakken and Eagle Ford plays in the United States.

In the United States, the US EIA estimates LTO resources at about 58 billion barrels, up from 35 billion barrels estimated in 2012 (US EIA, 2013b). This figure may well be revised again as more data become available. The USGS also reports undiscovered light tight oil onshore in the United States, with numbers smaller than the US EIA (13 billion barrels), though the definition of undiscovered is unclear (most LTO plays in the United States are known; the question is how much oil can be produced from them – the methodology used by the USGS is more geared to assessment of undrilled areas, whether discovered or not).

S P O T L I G H T

Has the rise of LTO resolved the debate about peak oil?

It has become fashionable to state that the shale gas and LTO revolutions in the United States have made the peak oil theory obsolete. Our point of view is that the basic arguments have not changed significantly. To understand why, it is useful to revisit the main peak oil argument, which is based on the observation that, for a given basin or country, the amount of oil found and the amount produced tend to follow a rising, peaking and then declining curve over time – known as a "Hubbert" curve. This is either because big fields tend to be found and produced first, followed by smaller fields as the basin matures, or because the cheapest fields are produced first and, as depletion sets in, costs increase (because of smaller, more complex fields) and the basin is outcompeted by other regions. This phenomenon has been observed in many countries (Laherrère, 2003). Where technology opens up a new set of resources that were not previously accessible (as with deepwater or LTO), there can be multiple Hubbert peaks, as each type of resource moves up and then down the curve.

The crux of the peak oil argument has been the assumption that these dynamics, which are well established empirically at the basin or country level, will also take place at the world level (an assumption that has not been vindicated by empirical facts so far). For the purposes of the peak oil argument, the advent of LTO (or other technology breakthroughs) may shift the overall peak in time, but it does not change the conclusion: once the peak is reached, decline inevitably follows rather quickly (and, given the amount of LTO resources compared to the total resources, it could be argued that the peak would be shifted by only a few years in any case).

It is this last assumption – that it is possible to transpose observed country or basin-level dynamics to the world level – that is open to serious doubt. In all the countries that have seen oil production peak, oil demand has continued to increase. This demand has been satisfied, where necessary, by imports from regions that were still pre-peak and therefore lower cost. At the world level, since there is no possibility to import, demand has to be equal to supply. If supply is limited, price will rise, reducing demand (and increasing supply). This price mechanism is expected to lead to a long plateau, or slow decline, rather than the rapid decline observed on a country-by-country basis.

With the acceptance that demand is as important as geology and price in determining worldwide supply, it becomes clear that other factors can play a crucial role. One that has been emphasised in successive *Outlooks* is the role of government policies. Whether driven by the desire to tackle climate change, or simply to encourage efficient uses of resources, government policies have a large effect on future oil demand. This is illustrated by the policy-driven differences between the scenarios; where we see that oil production peaks (as in the 450 Scenario) it is not because oil is becoming more difficult and more expensive to produce, but because demand decreases as a result of policy choices.

Taking into account the large amount of unconventional resources that becomes available as oil prices increase, in addition to the significant remaining conventional resources and the sizable potential for EOR in conventional fields, no peak occurs before the end of the projection period. (In peak oil language, the URR value that enters into the Hubbert equation is large enough to delay the peak until after 2035). This was already the case before LTO. It has not changed much with the arrival of LTO.

In last year's *Outlook*, a value of 240 billion barrels was used for worldwide LTO resources, based on the assumption that the extent and distribution of LTO and shale gas resources in the United States and worldwide would be roughly correlated. More bottom-up estimates have since been made, primarily by private consultancies, which range from 100 billion barrels to 600 billion barrels. In June 2013, the US EIA released the first publicly available study of a large number of basins in the world, with an estimate of the global technically recoverable LTO resource of close to 350 billion barrels and country estimates for the major resource-holders (Table 13.3) (US EIA, 2013a).[18] These US EIA numbers have been used as the basis of the projections this year.[19] In the United States, the current estimate of

18. The estimates leave out the unknown but potentially large resources in the Middle East, on the grounds that these are unlikely to be produced, given the large remaining amount of cheaper conventional oil.

19. Prior to the release of the 2013 US EIA study, information on LTO resources outside North America was very sparse, with only some basins in Argentina having been studied enough to provide solid estimates (at least 7 billion barrels, with significant upside). The Russian government agency, Rosnedra, has estimated recoverable tight oil resources in the Bazhenov shale in Western Siberia at more than 25 billion tonnes (180 billion barrels). ERCB estimates Alberta's light tight oil in-place at 424 billion barrels, of which 1-5% may be recoverable.

resources starts to constrain production levels before the end of the projection period (see Chapter 14). In the rest of the world, technical, economic and environmental constraints allow only much slower development, so that resources are not a limitation in the timeframe of this *Outlook*.

Table 13.3 ▷ Major LTO resource-holders (billion barrels)

Country	Areas assessed	Technical recoverable LTO resources
Russia	Bazhenov shale	76
United States	Bakken, Bone Springs, Eagle Ford, Granite Wash, Niobrara, Spraberry, Wolfcamp, Monterey and Woodford shales	58
China	Sichuan, Yangtze, Jianghan, Greater Subei, Tarim, Junggar and Songlia basins	32
Argentina	Neuquen, San Jorge, Magallanes and Parana basins	27
Libya	Ghadames, Sirte, and Murzuq basins	26
Australia	Cooper, Maryborough, Perth, Canning, Georgina, and Beetaloo basins	18
Venezuela	Maracaibo basin	13
Mexico	Burgos, Sabinas, Tampico, Tuxpan and Veracruz basins	13
Pakistan	lower Indus basin	9
Canada	Horn River, Cordova, Liard, Deep, Alberta, Windsor basins, Duvernay, Bakken, Utica shales	9

Source: US EIA (2013a).

Kerogen oil

Kerogen is the solid organic matter contained in shales that is the source of oil and gas. When heated under the right conditions, over geological time, kerogen is transformed into liquid or gaseous hydrocarbons. Shales containing kerogen are ubiquitous around the world. Some outcropping kerogen-rich shales have been exploited for centuries and burned for heat or power. If kerogen-containing shale is retorted (*i.e.* heated at a controlled rate), the kerogen can be transformed into liquid hydrocarbons. Kerogen oil is produced today in this way in small quantities in Estonia, China and Brazil.

The easiest kerogen shales to exploit are those near the surface, accessible with mining techniques. In principle, one can also exploit deeper deposits through in-situ heating, but the near-surface resources are already enormous. The largest known such kerogen shales are in the Utah/Colorado/Wyoming area of the United States. These have been studied in detail by the USGS and are thought to contain kerogen resources equivalent to 4 285 billion barrels of oil, of which more than 1 000 billion barrels is contained in the richest deposits that are more likely to be economically developed (USGS, 2012e). Several pilot projects have been demonstrating the technical feasibility of exploiting these deposits over the last 30 years, though there are significant environmental concerns related to water and land use.

Worldwide, the resources contained in near-surface kerogen shales are thought to be at least 1 100 billion barrels, with Jordan (30 billion barrels), Australia (12 billion), Estonia and China (4 billion each) and Israel, Morocco and Brazil (all around 3 billion) known to have large resources. Australia had planned a large-scale project in the Stuart shale in the 1990s but it was abandoned, in large part due to environmental concerns. Jordan, Israel and Morocco have a number of project proposals under study. Australia has recently approved a new pilot project, initially targeting 40 barrels per day.

Coal-to-liquids

The applicable resources for coal-to-liquids (liquid hydrocarbons produced from coal) are so vast that it is enough to focus solely on the proven reserves. If only 10% of global coal reserves were turned into liquid hydrocarbons, using known coal-to-liquids (CTL) technologies, this would produce 275 billion barrels of oil. With only 5.3 billion barrels of CTL projected to be produced in the New Policies Scenario to 2035 (6.0 billion barrels in the Current Policies Scenario), resources are clearly not a limitation. Economics and environmental acceptability are the constraints on CTL development. Countries with large, low cost coal resources and significant oil import needs, such as China or India, will lead the investments in this technology. Although not strictly speaking CTL, rapid development of coal-to-chemicals is taking place in China, displacing demand for oil as feedstock. (See Chapter 15 for a discussion of the petrochemicals sector.)

Gas-to-liquids

The resources available to transform natural gas to liquid hydrocarbons (GTL) are linked to the remaining recoverable resources of natural gas, estimated to be 810 trillion cubic metres (see Chapter 3). If 10% of this amount were transformed into liquid hydrocarbons with current GTL technologies, this would produce 280 billion barrels of liquids. This is more than ample to cover the most optimistic projections of use of GTL: in the New Policies Scenario, the cumulative production of GTL to 2035 is 4.1 billion barrels (4.6 billion barrels in the Current Policies Scenario).

More than 20% of gas resources are currently considered to be "stranded", meaning that they need construction of significant new transport infrastructure before they can be brought to market. For most of these stranded resources, pipeline construction is not an economic option, as the size of the field does not warrant the investment. Although today both liquefied natural gas (LNG) and GTL make sense only for large enough reservoirs, technical developments in floating LNG (which enables the LNG plant to be used on several fields over its lifetime), in small-scale LNG and in small-scale GTL are likely to open the development of such stranded resources. In this context, GTL will be competing with LNG; if the market were to be split 50/50 between the two technologies, this would correspond to 11% of gas resources being available for GTL.

Reserves

The standard PRMS definition of proven reserves, although it can be applied to unconventional resources such as oil sands or LTO, does not give a good feel for the amount of those resources that are likely to be developed. Indeed, because those resources tend to be large and spread over large geographical areas, they are developed piece-by-piece over many years. So in addition to the proven reserves amount, which corresponds to the part of the play for which there is a specific approved development project, it is useful to look at the total amount of recoverable resources that is known to exist and is thought to be currently economically and technically recoverable with reasonable certainty.

For oil sands, this is what the Canadian federal and provincial governments describe as "established" reserves. Canada's National Energy Board and Alberta's Energy Resources Conservation Board currently consider 168 billion barrels in this category, *i.e.* currently technically and economically recoverable in areas of planned developments (as not all these reserves correspond to sanctioned projects, this is a looser concept than strict PRMS 1P reserves).[20] Cumulative production from oil sands to 2035 in the New Policies Scenario is 27.2 billion barrels (28.4 billion barrels in the Current Policies Scenario). In addition to established reserves, Canada uses the concept of "ultimate potential" which is similar, but with lower probability of being geologically present and technically and economically recoverable under current conditions, somewhat along the lines of PRMS 2P reserves. The estimate for this category is 315 billion barrels (ERCB, 2013).

A similar question of definition arises for LTO. For example, in the Bakken play of North Dakota, it is expected that it will take 40 000 wells, drilled over twenty years, to develop the resources (NDDMR, 2012). Clearly the presence and economic and technical recoverability of the oil is very likely, but one cannot today assign a 90% or more probability to the drilling of 2 000 wells in 2030. So companies involved in LTO (or shale gas, for which a similar situation arises) tend to report both a PRMS proven amount and a resources amount that gives an indication of the amount they might be able to develop over the years. The company EOG Resources, for example, reports 552 million barrels of oil equivalent (boe) of proven reserves in the Eagle Ford play and 2 200 million boe of resources. World proven reserves of LTO (essentially all of it in the United States and Canada) are estimated at 5 billion barrels at the end of 2012.

For the Venezuela Orinoco belt, PDVSA has been regularly reporting updates to reserves as part of the progress with its Magna Reserva assessment project. The latest reported number stands at 220 billion barrels. The details have not been publicly documented, so it is unclear whether this is a proven reserves number (which seems unlikely, in view of the announced projects) or a 2P or 3P number, or rather whether it is an "established reserves"

20. ERCB, the Alberta Energy Resources Conservation Board has now been integrated in a new regulatory agency under the name Alberta Energy Regulator (AER).

number or an "ultimate potential" number.[21] Projected cumulative production to 2035 in the New Policies Scenario amounts to 11.8 billion barrels (12.7 billion barrels in the Current Policies Scenario).

Enabling technologies

How technology and learning-by-doing have unlocked LTO

One of the most important technological developments of the last decade has been the advent of multi-stage hydraulic fracturing in horizontal wells, unlocking vast new resources in low permeability, "tight" rocks. As a result of this "shale revolution", worldwide ultimately recoverable resources of oil have increased by as much as 350 billion barrels, and those of gas by 1 300 billion barrels of oil equivalent.

Horizontal wells have been routinely drilled since the 1980s. In the early 2000s, many new oil field developments outside the United States used horizontal wells; somewhat ironically, the lower 48 states in the United States was one of the few places still dominated by vertical wells. But this has changed dramatically over the last few years and, by early 2013, more than 60% of drilling rigs in the United States were drilling horizontal wells.

Hydraulic fracturing also has a long history, starting in the 1950s. By the early 2000s, it was routinely practiced in vertical wells around the world, and occasionally (as far back as the 1990s in the North Sea) in horizontal wells as well. Prior to its impact on the shale revolution, hydraulic fracturing had already been in large part responsible for the renaissance of Russian oil production in the mid-2000s. Since it increases productivity, hydraulic fracturing can be practised in most wells provided the value of the production increase exceeds the cost of the operation.[22]

The essence of the shale revolution has been process optimisation. A significant part of the cost of a hydraulic fracturing operation resides in the equipment used (trucks, pumps, mixing tanks, etc.). Performing multiple fracturing operations in the same horizontal well and drilling many wells in the same area maximise equipment utilisation, increasing the range of reservoir characteristics for which the operation is cost effective. In the early days of shale gas development in the Barnett shale, this alone was not sufficient and simplification of the fracturing fluid (*i.e*. the advent of the "slick-water" fracturing fluids) was required to achieve enough cost reduction to make the operation worthwhile. As the shale revolution took off, a series of further means of optimising the process were identified and others are under evaluation:

- More modular and mobile drilling rigs that can move to nearby locations easily without having to be fully dismantled.

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21. The target plateau production of all proposed projects amounts to about 1 billion barrels per year production (IEA, 2010). Even if maintained for 30 years, such projects would amount to only a small part of the Magna Reserva reserves number.

22. Exceptions are thin oil zones near oil-water contacts, where hydraulic fracturing might increase water production rather than oil (or gas) production, and reservoirs where the stress profile prevents the formation of hydraulic fractures.

- Pad drilling, *i.e*. drilling of multiple wells from a single drilling location, reducing site preparation costs.
- More rapid succession of the stages of multi-stage fracturing, thanks to ball-activated (or pressure- or tubing-activated) sleeves, or smart-fluids, allowing pumping at all the stages without pulling the equipment out of the wellbore.
- New approaches to water management, with piping and recycling at the field level, reducing supply costs.
- A number of companies are experimenting with gas-powered trucks and pumps to reduce fuel costs and reduce gas flaring in locations with no outlet to a gas market.

Most of these approaches contributed to the increased efficiency achieved over the last two years in some of the main shale plays in the United States. For example, in North Dakota (where most of the Bakken light tight oil play is found), 2 086 wells were spudded in 2012, (*i.e*. drilling started), using 200 drilling rigs, *i.e*. an average of ten wells per rig over the course of the year. This represents a significant improvement on the 2011 average of 8 wells per rig (1 528 wells with 182 rigs) (NDDMR, 2013). [23]

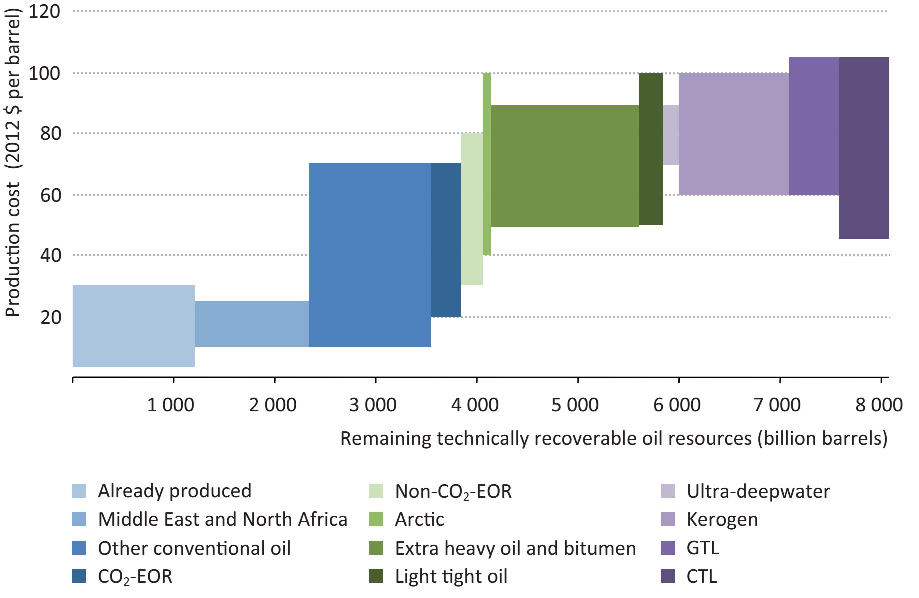
For all this progress, drilling for shale gas or light tight oil remains largely a trial-and-error operation. When moving into a new area, an operator will experiment with different lateral well lengths, different number of fracturing stages, different types of fracturing fluids and different perforation strategies until a combination that provides good economic returns is found. Finding the "sweet-spots", the parts of the reservoir that give good production, is also often hit-and-miss. In shale plays in the United States, currently about only one-third of the wells are economic and the good wells have to cover the costs of the less productive ones. If further process optimisation alone will probably give only slow additional cost gains, there is a large potential of further gains if new technological breakthroughs can improve this success rate.

Supply costs

Since 2005, the IEA has regularly published diagrams giving estimates of the oil price at which various amounts of resources can reasonably be expected to be produced (IEA, 2005). The most recent update is illustrated in Figure 13.17 (IEA, 2013). Such diagrams have been widely reproduced and are often used to argue that there is plenty of relatively "cheap" oil available. However, such figures can easily be over-interpreted and it is important to remember their limitations. The illustration shows the extent of various types of resources, as well as the range of oil prices that make production from these resources currently possible on a commercial basis in various parts of the world. But, clearly, not all the resources will, in practice, be produced under current conditions; with costs varying over time, today's economic prices may not represent the required prices at the time in the future when the resources will be produced.

23. Changes in average target depths have also contributed, as well as a reduction in weather-related downtime.

Figure 13.17 ▷ Supply costs of liquid fuels



Source: *Resources to Reserves* (IEA, 2013).

A more dynamic picture of the evolution of costs is captured in the World Energy Model (WEM) by three factors (not all of which push in the same direction):

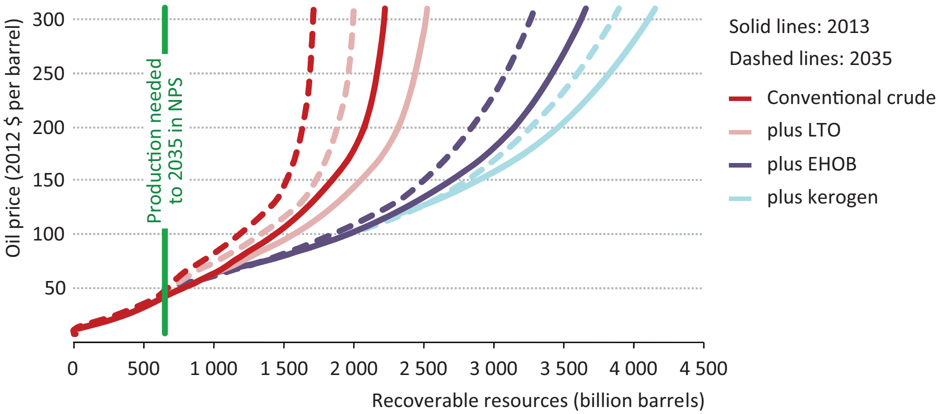
- Depletion of the resources in each country (and type of resources): as a larger fraction of the resources is produced, capital and operating costs increase.
- Technology learning: the evolution of existing technologies and the introduction of new ones tend to reduce the capital and operating costs with time.
- Industry-specific inflation: the period 2000-2008 clearly showed that, as an increasing oil price pushes up industry activity levels, so increasing supply and service costs also drive up capital and operating costs. The correlation between oil prices and industry costs observed during that time period is encapsulated in the WEM, so that higher oil prices lead to higher costs.[24]

The inputs to the WEM are not supply cost curves, but estimates of current costs by country and by type of oil (capital and operating costs, plus government take) which then evolve with time, subject to the three factors listed above (government take – as a percentage of net income -- and discount rates are normally kept constant throughout the projection

24. Some may argue that the 2000-2008 period was atypical, as the supply industry had to build-up very quickly after a decade of relatively low activity, leading to price tensions. However it is reasonable to expect that all industry participants (producers, supply and services companies, and governments awarding the licenses and imposing various production taxes) will always try to capture their share of higher oil prices, *de facto* pushing costs up proportionally.

period). So one can use the WEM to derive the implied supply cost curves at various times for different regions or different oil types (Figure 13.18).[25]

Figure 13.18 ▷ World supply cost curves for 2013 and 2035 in the New Policies Scenario



Notes: The supply curves are cumulative, *i.e*. the "plus LTO" line includes conventional crude and LTO; the "plus EHOB" includes conventional crude, LTO and EHOB, and so on. The vertical green line indicates the amount of production required between 2013 and 2035 in the New Policies Scenario (NPS).

For a given year (*e.g*. 2012), remaining recoverable oil is assumed to be produced with the technology learning factor of that year and the industry-specific inflation factor of that year, but the depletion factor increases as one moves up the curve. For each level of resources, a "breakeven oil price" can be calculated, being the oil price that gives a NPV of zero, with a discount rate of 10%. As expected, there is a large amount of conventional oil that can be produced at relatively low cost and, when oil prices increase, more unconventional resources are gradually opened up.

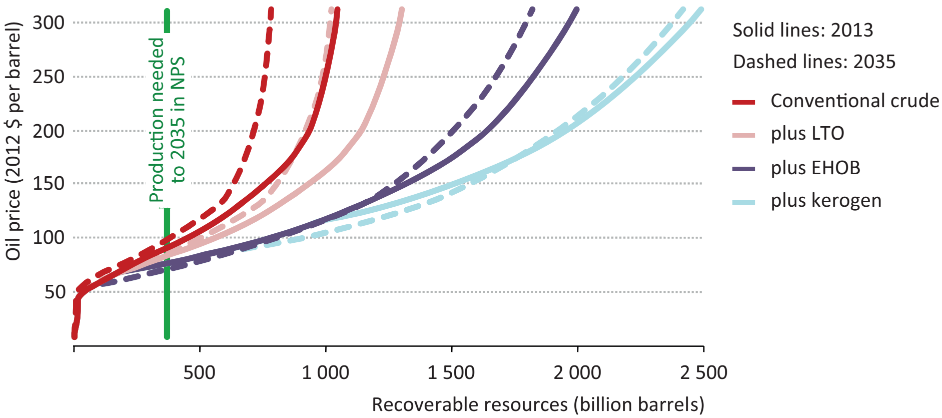
Since the cumulative production required in the New Policies Scenario between 2013 and 2035 is about 640 billion barrels (crude+LTO+EHOB+kerogen oil, *i.e*. excluding NGLs, GTL, CTL and additives), one might conclude from the figure above that the marginal barrel to meet this demand (the highest cost barrel produced to meet such a demand) costs only $50. However, the view at world level can be misleading as most of the low cost oil is located in OPEC countries, where production is limited as a matter of policy. It is therefore more meaningful to look at the same curves for non-OPEC countries (Figure 13.19, noting the change in scale on the horizontal axis).

The expected cumulative demand for oil from the non-OPEC countries in the New Policies Scenario is 380 billion barrels. On this basis, one still observes that the marginal barrel to meet the expected demand costs no more than $80-90/barrel, below the average IEA

25. CTL and GTL are not included as depletion does not affect their costs: feedstocks represent only a small fraction of their costs, which are dominated by investment and operating costs of the plant.

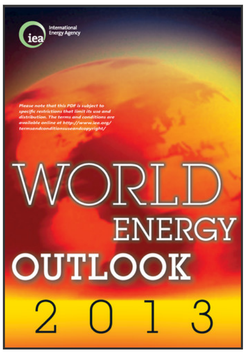
import price of $128/barrel in 2035. This is due to the fact that looking at resources is not enough: one must also look at production rates. The ability of the industry to develop new resources quickly is limited (in large part by the availability of skilled personnel, as well as the long timescales of new large projects). So there are constraints on supply keeping pace with demand, even though production projects may be highly profitable. The oil price trajectory, at a level above the marginal cost per barrel, serves the purpose of limiting demand to a level that can reasonably be expected to be supplied, given expected limitations in both OPEC and non-OPEC countries (see Box 1.3 for a discussion of how the oil prices used in this *Outlook* are determined).

Figure 13.19 ▷ Non-OPEC supply cost curves for 2013 and 2035 in the New Policies Scenario



Note: The vertical green line indicates the amount of production required between 2013 and 2035 in the New Policies Scenario (NPS).

In economic terms, this is a dynamic situation: the long-term equilibrium, in which price is equal to marginal production cost, is never reached (even if demand was constant, one would not necessarily reach equilibrium, because production from existing fields always declines and the industry has to invest constantly in new developments in order to meet demand). In principle, classical economic theory would imply that the industry would increase its intake and training of skilled personnel until this no longer represented a limitation, but empirical evidence suggests the oil industry is very risk averse in its recruiting policies, leading to long lasting imbalances. Another factor contributing to the difference between the marginal cost of supply and the projected price is that the latter is computed with a risk-free discount rate; provision for risks requires higher prices, as the market factors in risks, such as geo-political risks. The role of OPEC and the fiscal needs of some of the OPEC countries (see Chapter 14) can also contribute to maintaining elevated oil prices.



From:
World Energy Outlook 2013

Access the complete publication at:
https://doi.org/10.1787/weo-2013-en

Please cite this chapter as:

International Energy Agency (2013), “From oil resources to reserves”, in *World Energy Outlook 2013*, International Energy Agency, Paris.

DOI: https://doi.org/10.1787/weo-2013-16-en