Prospects for oil supply

Decline does not always lead to a fall

Highlights

- Oil supply is projected to reach 101 mb/d in 2035 in the New Policies Scenario, a rise of 12 mb/d from 2012. Key components of the increase are unconventional oil (up by 10 mb/d) and natural gas liquids (NGLs) accompanying the increase in global gas output (up by 5 mb/d). They fill the gap between increasing global demand and conventional crude oil production; the latter's share in total oil production falls, from 80% in 2012 to two-thirds in 2035, despite rising offshore deepwater output.

- Analysis of more than 1 600 fields confirms that the observed decline rate for conventional fields that have passed their peak – averaged across all fields and weighted by their cumulative production – is around 6% per year. Decline rates vary substantially by field size, with the largest fields having the lowest rates of decline and onshore fields depleting more slowly than offshore. Conventional crude output from existing fields is set to fall by around 40 mb/d by 2035.

- Unconventional plays, such as light tight oil or oil sands, are heavily dependent on continuous investment and drilling to prevent the large initial decline rates for individual wells translating into rapid field-level declines. In our projections, production of LTO does not take off at scale outside North America before 2035, but still reaches 5.9 mb/d by the mid-2020s.

- The role of OPEC in quenching the world's thirst for oil is temporarily reduced over the next ten years, due to rapid growth of supply from LTO in the United States, from oil sands in Canada, from deepwater production in Brazil and from NGLs from all over the world, but the share of OPEC countries in global output rises again in the 2020s, as they remain the only large source of relatively low cost oil. Iraq is the single largest contributor to global production growth.

- Supply developments exceed expectations in a Low Oil-Price Case, easing market balances and bringing the oil price down to $80/barrel for the duration of the *Outlook* period. The result is an increase in oil demand, which reaches almost 108 mb/d in 2035 (6.5 mb/d higher than in the New Policies Scenario). OPEC countries provide the bulk of the increase in demand in 2035, but their revenues fall.

- Declining output from existing fields is a major driver of upstream investment. Total upstream spending in the oil and gas sectors is expected to rise to more than $700 billion in 2013, a new high, and the projections call for spending to remain around these levels for the next decade, before the annual average dips slightly, as non-OPEC supply starts to tail off and lower cost OPEC Middle East countries (through their national oil companies) provide most of the increase in supply.

Global oil supply trends

Global oil supply differs strikingly across the three main scenarios analysed in this *Outlook*, in line with the wide variations in demand.[1] From a starting point of 89 million barrels per day (mb/d) in 2012, there is a 33 mb/d difference by 2035 in projected oil supply between the Current Policies Scenario, where it reaches 111 mb/d and the 450 Scenario, where oil demand – and therefore supply – starts to drop in the mid-2020s, declining to 78 mb/d in 2035. The focus in this chapter is the central, New Policies Scenario, which falls in between these two, with supply raising to 101 mb/d in 2035 (Table 14.1).

Table 14.1 ▷ Oil production and supply by source and scenario (mb/d)

			New Policies		Current Policies		450 Scenario	
	1990	2012	2020	2035	2020	2035	2020	2035
OPEC	**23.9**	**37.6**	**37.8**	**45.2**	**38.3**	**49.3**	**36.1**	**34.4**
Crude oil	21.9	30.9	29.4	33.0	29.7	36.2	28.4	25.4
Natural gas liquids	2.0	6.1	6.8	9.3	7.0	9.9	6.2	6.9
Unconventional	0.0	0.6	1.6	2.8	1.6	3.2	1.5	2.1
Non-OPEC	**41.7**	**49.4**	**55.0**	**52.9**	**56.1**	**58.1**	**52.5**	**41.3**
Crude oil	37.6	38.4	38.3	32.3	38.9	35.2	36.7	25.4
Natural gas liquids	3.6	6.6	8.0	8.3	8.2	9.0	7.5	6.6
Unconventional	0.4	4.4	8.8	12.3	9.0	13.9	8.4	9.2
World oil production	**65.6**	**87.1**	**92.8**	**98.1**	**94.4**	**107.4**	**88.6**	**75.7**
Crude oil	59.6	69.4	67.7	65.4	68.6	71.4	65.1	50.8
Natural gas liquids	5.6	12.7	14.8	17.7	15.2	18.9	13.7	13.6
Unconventional	0.4	5.0	10.4	15.0	10.6	17.1	9.8	11.3
Processing gains	*1.3*	*2.1*	*2.6*	*3.3*	*2.6*	*3.6*	*2.5*	*2.5*
World oil supply*	**66.9**	**89.2**	**95.4**	**101.4**	**97.1**	**111.0**	**91.1**	**78.2**
World biofuels supply**	0.1	1.3	2.1	4.1	1.9	3.3	2.6	7.7
World total liquids supply	**67.0**	**90.5**	**97.6**	**105.5**	**98.9**	**114.3**	**93.8**	**85.9**

* Differences between historical supply and demand volumes given in Chapter 15 are due to changes in stocks. ** Expressed in energy-equivalent volumes of gasoline and diesel. The average energy to volume conversion factor is close to 7.8 barrels per tonne of oil equivalent throughout the projection period in the New Policies Scenario, reflecting the projected share of biodiesel versus ethanol.

The three main components of oil production – crude oil, natural gas liquids (NGLs) and unconventional oil – adjust to the different scenarios in their own ways. Production of conventional crude oil sees relatively little of the upside in the scenarios in which demand increases, as there are limits imposed by investments and by policy on how quickly production can grow, and crude oil production takes a disproportionate share of the downside in the 450 Scenario. Output of NGLs proceeds according to a separate logic, in

1. As described in Chapter 13, oil supply denotes production of conventional and unconventional oil and NGLs plus processing gains, the latter being the volume increase in supply that occurs during crude oil refining.

that their availability is driven by the dynamics of the gas market rather than that of oil: in line with the trajectories for gas demand (see Chapter 3), production of NGLs increases in all the cases examined, albeit less strongly in the 450 Scenario.

Production of unconventional oil also rises in all scenarios, proving robust even in the conditions of the 450 Scenario, where overall oil consumption is declining. This is because many unconventional projects – for example in oil sands or extra-heavy oil – depend on large upfront capital investment and then produce at steady rates for a long time, so projects started before demand flattens out will continue to produce.[2] One other component of supply that rises in all scenarios is "processing gains", which refer to the volumetric increase in production as it passes through the refining sector.

Decline rate analysis

The importance of decline

The rate at which the output of currently producing oil fields declines is a major factor determining the pattern of future supply. This decline has to be compensated for by developing new reserves in known fields, by discovering and developing new fields or by developing unconventional resources, such as oil sands, which may come at higher economic and sometimes environmental costs. All of these processes require large, continuous commitments of capital from the oil industry in exploration and production. This explains a leitmotif of the *World Energy Outlook* (*WEO*) year after year: the main threat to future oil supply security is insufficient investment.

A small difference in the decline rate makes a large difference to the investment requirement and can, therefore, have a large influence on future market conditions. In the projections, the compound annual decline rate of currently producing conventional fields is around 4%. If this decline rate were to be one percentage point higher, at 5%, the additional amount of "new" oil needed over the projection period would be 6 mb/d, close to the difference between the New Policies Scenario and the Current Policies Scenario. This implies that oil prices would have to be about $15 per barrel (12%) higher. Conversely, a smaller rate of decline would lead to a much more comfortable oil market balance.

For these reasons, understanding decline rates in currently producing oil fields is a cornerstone of the assessment of the outlook for oil markets. The IEA published an analysis of decline rates in the *WEO-2008*, and we revisit the issue in this *Outlook* to see how the picture might have changed. Technology may be evolving so as to reduce decline rates, or ever-increasing depletion could, on the contrary, be increasing them. New and growing types of supply such as light tight oil or extra-heavy oil may also be altering the global picture.

2. Even coal-to-liquids output expands in the 450 Scenario, where low coal demand and coal prices provide a strong incentive to turn coal into more valuable hydrocarbon liquids; since carbon capture and storage technology is widely deployed in this scenario, it can be used at relatively small additional cost per barrel to limit CTL CO_2 emissions.

Box 14.1 ▷ Why does production decline?

A conventional oil field usually starts producing under "primary recovery": the pressure of the fluids (oil, gas and water) contained in the reservoir drives the oil towards the wells. Once in a well, the oil can flow naturally to the surface, pushed by this reservoir pressure, or can be lifted by pumps or other artificial lift techniques. As oil is produced, reservoir pressure drops as the remaining fluids fill the gap left by the produced oil, and therefore the driving force decreases, leading to decreasing output, *i.e.* decline. At a certain point in the pressure drop (sometimes almost from the beginning of production), the operator will start a pressure maintenance programme by injecting water in the reservoir through different "injector" wells.[3] This is secondary recovery, or water flood.

If the volumes injected match the volumes of oil produced, pressure will be maintained and decline arrested. However, more subtle decline mechanisms soon come into play. As more water is injected, water becomes more mobile than oil and more and more water eventually reaches the production wells. Pressure maintenance can keep the total flow rate constant, but more water inflow means that less oil is produced: decline has set in again. Over time, the wells produce smaller and smaller amounts of oil, until the value of the oil becomes insufficient to pay for the costs of injection, lifting (if needed) and oil/water separation and the wells will be shut-in. In some cases, the operator may embark on tertiary recovery, using the enhanced oil recovery (EOR) techniques described in Chapter 13.

A starting point for the analysis is to review why output from oil fields declines. At the level of an individual well, this is linked to the basic mechanisms of recovery (Box 14.1). At the level of a conventional oil field, the dynamics are slightly different. A field is divided into sections that are tapped by different wells (either because the different sections [reservoir compartments] are not hydraulically well-connected or because the field is large and it would take too long to drain it with a single well). So the actual field-level decline depends in large part on the schedule for drilling wells. Typically, an operator will drill a number of wells, one after another, during the early part of the life of the field, leading to a gradual increase in production as more wells come on-stream, called the ramp-up phase. The operator then produces with a fixed number of wells for a while, leading to a plateau phase and a gradual decline as each well declines; then starts drilling new wells, a process called in-fill drilling, as part of an "improved oil recovery" programme based on an assessment of where there is oil remaining and how best to target it. The operator may also resort to enhanced oil recovery (EOR) techniques to extract a further proportion of the oil (see focus on EOR in Chapter 13).

In fields where drilling is expensive, such as offshore deepwater fields, these processes may occur in rapid succession as the operator tries to accelerate production as much as possible,

3. For simplicity we describe only water injection; similar mechanisms, leading to similar results, also result from pressure maintenance with gas injection.

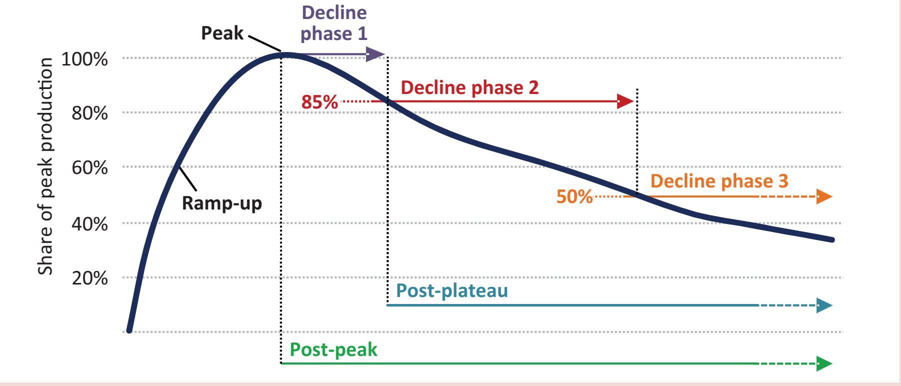
leading to a rapid ramp-up, short peak and rapid decline. In other fields, such as onshore super-giants, the economics allow for a more leisurely development and the production profile may be determined more by national policies on the desirable production and recovery rates. A large onshore field may be developed in successive tranches, thereby maintaining a steady production plateau for a long time. In such a case, decline at the field level becomes observable only towards the end of the productive life of the field.

Box 14.2 ▷ Concepts used in the decline rate analysis

This analysis is limited to fields that are in decline, *i.e.* fields for which production in a given year has been lower than the highest production level previously reached. We also distinguish between *observed decline rates*, which are derived from the actual production histories of the various fields in our database and which include the effect of continuing investment by operators to mitigate the effects of decline, and *natural decline rates*, which we calculate as the decline rates that would have been seen in the absence of these investments. We calculate decline rates for individual fields as the compound annual decline rate (CADR) since the year in which production peaked. These are then combined into representative decline rates for types of field, for countries, regions or for the world as a whole, by weighting the contribution of each field according to its cumulative production to 2012. This produces a weighted average CADR.

All fields that are in decline are said to be "post-peak". To provide a more detailed analysis, these fields can be further divided into decline phases 1, 2 or 3 (Figure 14.1), as was done in the study published in *WEO-2008*. Decline phase 1 covers the years between peak and the first year when production goes below 85% of peak. Decline phase 2 is between the end of phase 1 and the last year in which production is above 50% of peak production. Decline phase 3 is reached when production is consistently below 50% of peak. Fields in decline phases 2 or 3 are said to be "post-plateau".

Figure 14.1 ▷ Indicative illustration of decline phases and concepts



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Decline is therefore field-dependent, both because the reservoir characteristics vary and because development strategies vary. The operator will typically construct a computer model of the field and will be able to predict decline under various assumptions about future investment (*e.g.* drilling more wells, changing injection patterns). These models are normally proprietary and the expectations about future decline are not publicly available (and future investment patterns are, in any case, subject to change). Without access to the reservoir models for the 8 000 or so producing conventional oil fields in the world, an alternative approach is to analyse past production to infer likely future patterns of decline. This is the basis for the findings presented here.

Decline rates for conventional oil

Field database

The basis used here for estimating decline from historical production data is a field-by-field production database. In *WEO-2008*, we used a database of 798 fields, coming from various sources. This year we have used a database of 1 634 currently producing, conventional oil fields, for which the available historical production time series is thought to be reliable (Table 14.2). The period covered by the database is 1950 to 2012 and the fields in the database represent close to two-thirds of global production of conventional crude oil.

Table 14.2 ▷ Breakdown of the field database by field size (recoverable resources) and geographic location

	Super-giants	Giants	Large	Small	All sizes
Million barrels	*More than 5 000*	*500 to 5 000*	*100 to 500*	*Less than 100*	
Onshore	38	227	550	352	1 167
Offshore	14	79	193	181	467
Depth up to 125 metres	13	55	129	143	340
Depth from 125 to 1 500 metres	1	23	62	36	122
Depth greater than 1 500 metres	0	1	2	2	5
Total	**52**	**306**	**743**	**533**	**1 634**
OPEC	36	118	202	112	468

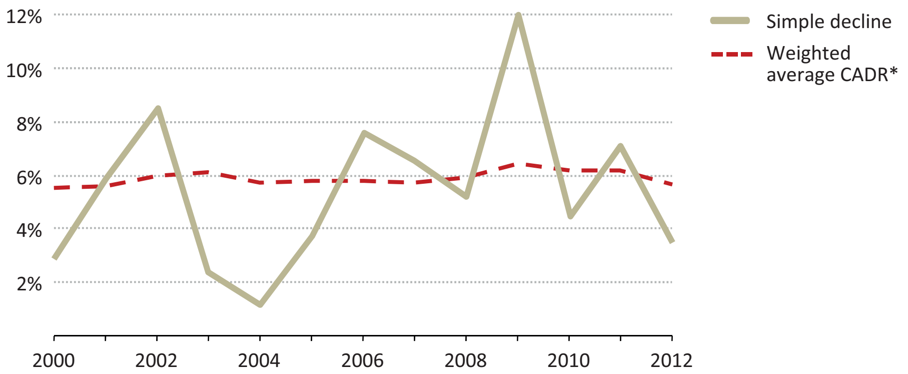
World production decline rates

With a database of fields that includes historical records for production, a first task is to look only at those fields that are in decline. One approach is to sum up the output from all these post-peak fields in a given year and compare this with production from the same set of fields in the previous year, defining an "observed year-on-year decline rate". This decline rate can be calculated for any year and the results for the period 2000-2012 are shown in Figure 14.2 as the "simple decline" line.[4] This approach shows a wide year-on-year variation, because production in any given year is affected by many factors (such as OPEC

4. With the change of year, the set of fields that are in decline that year also changes: the database contains 1 524 fields that were post-peak in 2012, but only 957 that were post-peak in year 2000.

production constraints, maintenance programmes, fluctuating oil demand), which tend to skew the overall result. The high observed decline rate figure for 2009 is a case in point: demand was subdued that year, because of the economic crisis, and clearly production in a number of fields was deliberately reduced because of weak demand.[5]

Figure 14.2 ▷ Observed year-on-year decline rate and weighted average CADR* for conventional oil fields



* Compound annual decline rate.

Sources: Rystad Energy AS; IEA analysis and databases.

Because of these large year-to-year fluctuations, we use a different approach for the analysis of decline rates. We select all the fields that are post-peak in a given year. For each of these, we calculate the compound annual decline rate since the year in which production peaked. This approach is much less sensitive to year-to-year variations than the calculation of a one-year decline. But it still leaves the question of how to average those individual field decline rates to obtain a representative world level decline rate. The method used is to calculate a weighted average decline rate, weighing each field by its cumulative production to 2012 (Figure 14.2, red dashed line).

With this methodology, the year-on-year changes are relatively small and the weighted average world decline rate settles at around 6%, a finding consistent with the similar analysis conducted in *WEO-2008*.[6] No significant change in decline rates for conventional oil fields can be seen over the past twelve years.

5. The observed decline rates shown here are slightly lower than those observed through a similar approach in *WEO-2008*. This is linked to a difference in methodology: unlike in 2008, we have included here all post-peak fields, including those whose production was post-peak but nonetheless saw some year-on-year increases. In the first part of the 2000s, for example, many post-peak Russian fields saw increases in production. This situation also arises in some OPEC fields, as their production fluctuates according to OPEC or individual members' production policy. The results of the new methodology are less affected by such fluctuations and therefore more robust.

6. The *WEO-2008* weighted average world decline rate was 5.1%. The database used at the time was smaller than the one used here, with a bias towards larger fields, so the calculation was extrapolated to a figure of 6.7% for all producing fields. The value of 6% seen here falls between the observed and extrapolated values of *WEO-2008*.

Decline rates by field type and by decline stage

Breaking down decline rates by the type of conventional field shows some wide variations (see last column of Table 14.3). Production from larger fields tends to decline more slowly than from smaller fields. Production from offshore fields tends to decline more quickly than onshore fields. Because of these differences, the decline rates calculated for OPEC (where fields tend to be very large and onshore) are significantly lower than those for non-OPEC conventional production.

Table 14.3 ▷ Weighted average CADR to 2012 by decline phase[7] (%)

	Decline Phase 1	Decline Phase 2	Decline Phase 3	Post-plateau	Post-peak
Onshore	3.4	2.5	7.7	5.4	5.4
Offshore					
Shallow	5.2	1.6	12.9	8.2	7.5
Deepwater (including ultra-deepwater)	12.3	7.9	14.1	12.9	12.7
Super-giant	4.6	1.1	7.3	4.4	4.0
Giant	5.1	4.5	10.6	7.8	8.0
Large	4.5	5.4	10.8	9.1	9.3
Small	4.0	8.1	12.6	11.4	11.9
All fields	**4.8**	**2.4**	**9.2**	**6.4**	**6.2**
Non-OPEC	5.2	3.6	9.4	8.1	7.8
OPEC	3.9	1.7	9.0	4.2	4.5

* Compound average annual decline rate.

Note: For field type size and geographic location refer to Table 14.2.

A single decline rate for world production, even when broken down for different types of fields, is still not a very robust basis for long-term projections of supply. This is because decline rates also vary according to the point reached in its decline by a given field: using the generic decline rates to project future production would be unsatisfactory since, as years pass, the number of fields in the different phases of decline may vary. That is why, in Table 14.3, we further divide the period of post-peak decline into three distinct phases, calculating weighted average decline rates for each phase.[8]

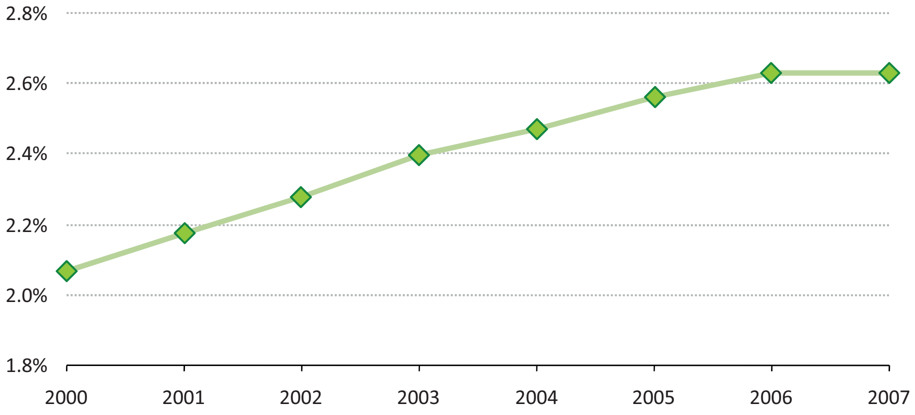
7. These results are consistent with the analysis conducted in *WEO-2008*. The larger decline figures for Phase 1 are not statistically significant. Because of the weighting by cumulative production, super-giant fields tend to dominate the global averages and there are very few (less than half a dozen, depending on the year) super-giants in Phase 1. After a short peak, these fields tend to be maintained at plateau in phase 2 for a very long time, which explains the low decline rates in this phase.

8. For each phase a field decline rate is defined as the compound annual decline rate from the beginning of the phase to either the end of the phase or the last year for which production data is available. These field decline rates are then weighted by the cumulative field production to 2012 to obtain a world average for each phase (fields that stop producing are excluded from the calculation).

Natural decline rates

It is important to distinguish the observed decline rates, discussed thus far, from natural decline rates, which are the rates of decline that would be seen if investment in those fields were stopped. In a currently producing field, the operator will typically invest to try and mitigate decline, taking such actions as drilling more wells in already developed parts of the reservoir (in-fill drilling), installing new water injection capacity, developing new parts of the field or even applying some EOR technologies.[9] Natural decline is a very important parameter in the supply modelling, because it drives the need for future investment in existing fields. We estimate the difference between observed and natural decline rates by using industry databases on the amount of capital investment spent each year in currently producing fields, together with making assumptions about the efficiency of these investments (barrel per day added per unit of investment). In this way, we can estimate what the production from those fields would have been in the absence of the additional expenditure, leaving us with a production-weighted average difference between the natural decline rate and the observed decline rate.

Figure 14.3 ▷ Estimated difference between natural and observed decline rates in currently producing conventional fields



Note: The decline rate is estimated using at least five years of natural decline, so here data to 2012 are used.
Sources: Rystad Energy AS; IEA databases and analysis.

We estimate that the global average difference between the observed and natural decline rates is around 2.5 percentage points (Figure 14.3). This implies that the impact of the ongoing investment by operators in currently producing fields is to reduce, by 2.5% on average, the decline rates that would otherwise be seen. There is a small upward trend in this number over time, but this is relatively small and could well reflect

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9. The operator also spends money every year – operating costs – for a number of actions that are not normally considered capital investment, such as cleaning well bores or reservoir zones near wellbores, installing, running or replacing pumps, re-perforating, performing well stimulation treatments, adjusting chokes in injections or production wells, etc. The definition of capital and operational expenses may depend on local accounting rules.

inaccurate estimates of the efficiency of capital investment, rather than a real increase in natural decline rates. The result of this analysis is similar to the estimate made in *WEO-2008* of 2.3%, a good match given that the required parameters can only be estimated approximately. Adding our new estimate to the current observed decline rate of 6% (Figure 14.2) gives an average production-weighted figure for natural decline of close to 9% for the post-peak fields in the database.

Decline rates for unconventional oil

Unconventional sources of oil have different decline patterns from those of conventional oil and understanding these differences is important, given the growing role of unconventional sources in meeting future oil demand. As discussed in Chapter 13, the main resource types are light tight oil (LTO), Canadian oil sands and Venezuelan Orinoco belt extra-heavy oil. We also have projections for production of coal-to-liquids (CTL), gas-to-liquids (GTL), additives[10] and kerogen oil.

LTO and Canadian oil sands have similar decline characteristics. The resources are spread over large geographical areas and each well[11] produces only a small amount over a relatively short time period: it takes many wells to achieve substantial production and continuous drilling to maintain production. As a result, the decline rate at field level is mostly driven by the drilling schedule, *i.e.* the rate of investment. Production ramps-up as the number of wells drilled per year increases, then can reach a long plateau as the drilling rate stabilises and a rapid decline as drilling locations diminish.[12] These features have implications for the discussion of decline rates and future patterns of investment, particularly in relation to LTO (Spotlight).

Among the other types of unconventional oil, Venezuelan extra-heavy oil is produced either by primary recovery with horizontal wells, in which case it follows a pattern similar to conventional oil reservoirs during primary recovery, or by heating the oil with injected steam, in which case it follows a pattern similar to that of Canadian oil sands. CTL, GTL and additives are produced in large industrial plants, requiring very large upfront investments. As a consequence, plants are built only in places where the supply of feedstock is secure for the lifetime of the plant. In addition, because of the large upfront investment, the operator will try to produce at a level as close to maximum capacity as market conditions and maintenance schedules allow. The result is basically no decline during the nominal lifetime of the plant (normally 25 to 30 years), possibly followed by rapid ramp-down as the depreciated plant is superseded by newer plants using new technologies. Given the

10. Compounds such as MTBE, ETBE and methanol that are added to gasoline to adjust its performance, coming at least in part from gas or coal feedstocks.

11. Or pair of wells in the case of Steam-Assisted Gravity Drainage (SAGD) technology in Canadian oil sands, or each shovel for mined oil sands.

12. In-situ oil sands projects in particular will try to maintain a long plateau at the capacity of the steam plants, which represent a significant upfront capital investment. (See *WEO-2010* for a discussion of oil sands technologies [IEA, 2010]).

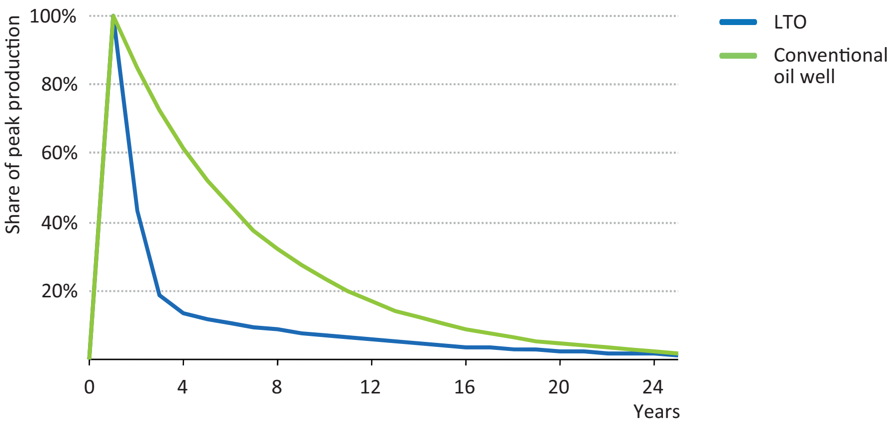
very small number of active CTL and GTL plants in the world, only small pilot plants have been retired so far. Experience with kerogen oil production is very limited but, as it is more akin to a mining process, a long plateau can be expected, followed by abrupt decline once resources are no longer exploited.

S P O T L I G H T

What does the rise of light tight oil mean for decline rates?

It is sometimes argued that the advent of LTO in the United States means a significant change to the likely evolution of decline rates. This stems from the fact that the decline in production of each well is very rapid compared with production from a typical conventional oil well (Figure 14.4). Because of the very low permeability of the rock, each LTO well – even with hydraulic fracturing – drains only a very small volume of the overall reservoir. Initial production consists largely of the oil contained in fractures or fissures (either pre-existing or generated by hydraulic pressure). These drain rapidly and then there is a long tail of low-level production. If the reservoir pressure is sufficient and the reservoir does not contain water, the low production level can be maintained for a long time, as lifting costs (including gas flaring costs, if required) are low. However, if any pumping is required or water production sets in, the well quickly becomes uneconomic and needs to be shut-in and abandoned.

Figure 14.4 ▷ Typical production curve for a light tight oil well compared with a conventional oil well



This characteristic does not necessarily affect the observed decline rates at the field level, which are not significantly different from conventional fields. Each well may decline quickly, but there are many possible drilling locations in the field (as each well drains only a small part of the reservoir). As long as drilling continues, production can be maintained. So the advent of light tight oil does not significantly affect the field-level analysis of observed decline rates presented so far.

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Natural decline rates, however, are strongly affected by this production profile as, by definition, they are the decline rates that would be observed if investment stopped. Natural decline rates in LTO fields would not be quite as steep as the well decline rates, because wells are often drilled and completed as a batch; at any moment in time, an operator will typically have a stock of wells that are ready to be put into production but are not yet connected to the production gathering system. Still, natural decline rates for LTO fields can be expected to be in the order of 30% per year for the first three years in a typical LTO play (meaning that production falls to around one-third of the initial production level after this time), before stabilising at around 5% per year.

These large initial natural decline rates make LTO production potentially much more responsive to fluctuations in oil prices than conventional fields: a decision to stop drilling translates into a rapid fall in output. This creates the possibility that LTO could absorb at least some part of the risk of variable global demand and price volatility. Whether this will happen in practice has yet to be tested. There are limits to the amount of flexibility that might be available: operators may, for example, hedge output at certain price levels, which would limit their incentive to respond to short-term price signals. And, even though a fall in production is easily achieved by stopping drilling activity, ramping-up again can take longer: drilling rigs and hydraulic fracturing fleets need to be brought back on line, which may require both equipment and personnel moves.

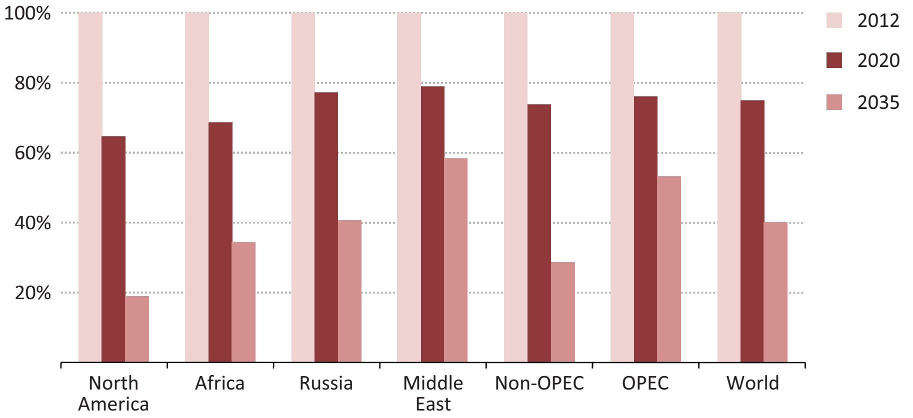
Implications for future production

Future production from currently producing conventional fields

On the basis of our analysis of historical decline rates, we now have the main ingredients required to project production from existing conventional fields.[13] In the New Policies Scenario, the result is that the year-on-year decline in output from all currently producing conventional fields gradually increases, from 2% in the early years of the projection period (as some existing fields are still ramping up) to around 4.7% in the early 2020s, and then stabilises around 4% by the end of the projection period. That this decline rate settles around 4% (rather than at 6%, which is the CADR for all fields) is linked to the fact that, by the 2030s, the remaining production from currently producing fields is concentrated in large onshore fields (mostly in OPEC countries); as shown in Table 14.3, these fields have the lowest decline rates, around 4%.

13. For each field in the database, this would mean assigning a field type and determining the decline phase, then projecting future production for the field as per the corresponding decline rate in Table 14.4, updating decline rates as the field moves into a different phase. The main remaining uncertainty is over fields that are not in the database and over projected output from fields that are currently ramping up (*i.e.* one needs to know their future peak year and peak production). The World Energy Model (WEM) methodology for this calculation, which is verified against a proprietary commercial database that contains a representation of possible future production for all fields in the world, is described in the WEM documentation available at *www.worldenergyoutlook.org*.

Figure 14.5 ▷ **Decline in production of conventional crude from currently producing fields in selected regions in the New Policies Scenario**



The speed at which output from currently producing fields declines over the projection period varies substantially by region (Figure 14.5). This is related to differences in the average size of fields, which is related, in turn, to the extent to which resources are already depleted and to whether the fields are onshore or offshore. The Middle East has the lowest projected decline to 2020 and 2035 (shown as a percentage of 2012 production) because of the preponderance of very large, onshore fields. This has, in turn, a strong influence on the figures for OPEC as a whole.

At the other end of the scale, in North America, fields in production today produce less than one-fifth of today's conventional crude output by 2035. For the world as a whole, conventional crude output from existing fields falls from 69 mb/d today to 28 mb/d by 2035, meaning that about 40 mb/d of capacity (or more than 20 times today's production of LTO) needs to be added over the projection period just to compensate for the effects of decline in conventional fields.

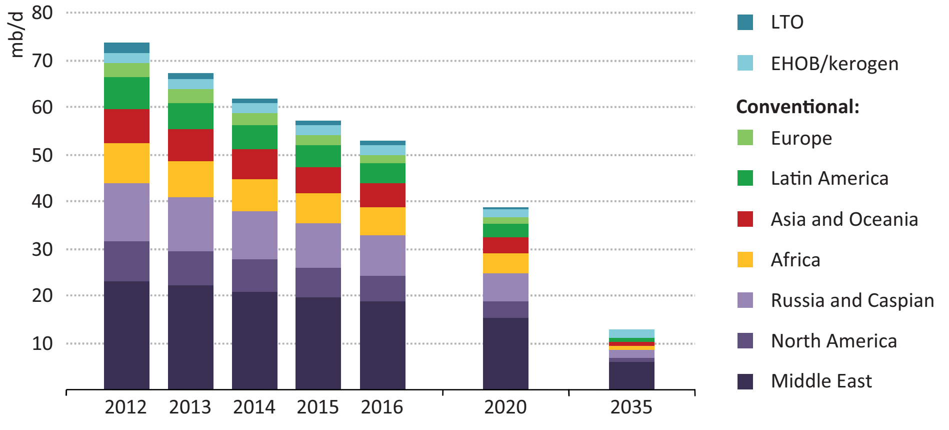
Future production from all fields

As discussed, adding unconventional oil into the equation does not have large implications for global observed decline rates, but it does increase the dependence of overall oil production on continuous investment. This can be seen by examining natural decline rates (Figure 14.6).[14] In this case, the fall in production is even steeper, with oil output (excluding NGLs) dropping from 74 mb/d in 2012 to less than 13 mb/d in 2035, half of which would be from large onshore fields in the Middle East where decline rate are lowest. This puts

14. LTO output falls off rapidly, but the effect on overall natural decline rate is offset by the much slower decline in extra-heavy oil and bitumen. Our modelling of slow natural decline for oil sands and extra-heavy oil is a simplification, as, for example in in-situ production of oil sands, one needs to continue drilling pairs of shallow wells to maintain production, but these investments are very small compared with the initial upfront investment, so a low natural decline is a good approximation.

a new perspective on the challenge facing the upstream oil industry. Raising production (excluding NGLs) from 74 mb/d in 2012 to 80 mb/d in 2035 might appear to be a relatively modest undertaking, involving the addition of 6 mb/d. Once, though, it is understood that the actual requirement is to add close to 67 mb/d to reach the 80 mb/d target, both through net capacity additions and efforts to mitigate decline at existing fields, the scale of the task becomes clearer.

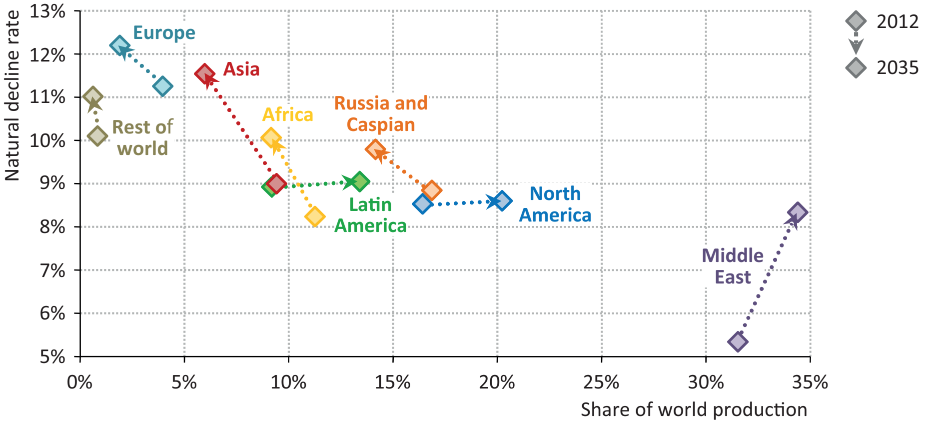
Figure 14.6 ▷ Production that would be observed from all currently producing fields in the absence of further investment (excluding NGLs)



Note: EHOB = extra-heavy oil and bitumen.

The question of how natural decline rates will evolve in the future is complex, as the mix of fields constantly evolves. On the one hand, world production becomes more and more dominated by large, ageing fields in OPEC Middle East countries, with relatively lower decline rates. On the other hand, the remaining production in many other parts of the world tends to come from smaller and smaller fields with higher decline rates, though this may be counter-balanced by the fact that a greater proportion of these may be in the early part of their decline (phases 1 and 2), when the decline rates are lower. Over the first half of the projection period, this trend is also affected by the start of production at some giant and super-giant fields in Brazil and Kazakhstan. Finally, the partially offsetting contributions of LTO and EHOB evolve as the mix between the two changes and their overall contribution to total supply grows. Overall, natural decline rates are projected to increase modestly in all regions between 2013 and 2035 (Figure 14.7). This trend could be modified by wider deployment of EOR technologies, although rapid growth is not projected in this area (see focus on EOR in Chapter 13).

Figure 14.7 ▷ Projected evolution of natural decline rates in key regions in the New Policies Scenario, 2012-2035



Oil production by type

Four main sources of oil production that are developed over the projection period can usefully be distinguished. There are conventional fields that are known but not yet developed; new conventional fields that are expected to be discovered and developed during the projection period; growing production from unconventional oil sources; and a rapidly growing amount of NGLs accompanying the worldwide growth in gas production. In the New Policies Scenario, these sources take global oil production from 87 mb/d in 2012 to 98 mb/d in 2035 (Table 14.4).

Table 14.4 ▷ World oil production by type in the New Policies Scenario (mb/d)

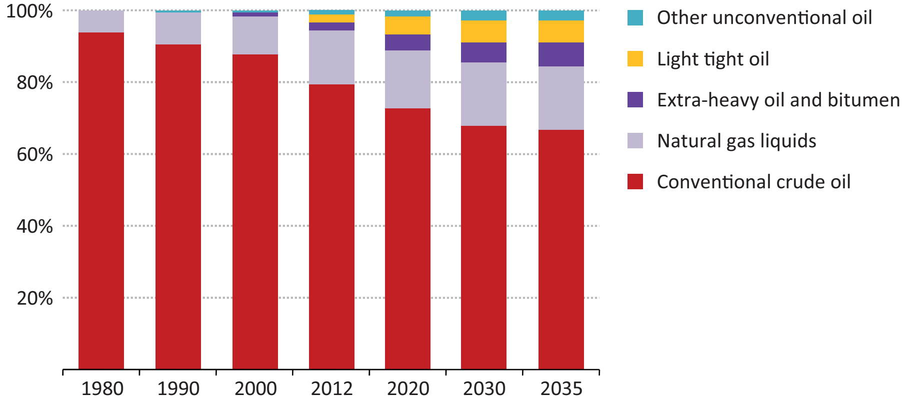
	2000	2012	2020	2025	2030	2035	2012-2035	
							Delta	CAAGR*
Conventional	**73.8**	**82.1**	**82.5**	**82.5**	**82.3**	**83.1**	**1.0**	**0.1%**
Conventional crude oil	66.0	69.4	67.7	66.6	65.5	65.4	-4.0	-0.3%
Existing fields	64.5	68.0	50.9	40.9	32.8	27.1	-41.0	-3.9%
Yet-to-be-developed	n.a.	n.a.	13.9	16.6	18.1	19.8	19.8	n.a.
Yet-to-be-found	n.a.	n.a.	1.4	7.2	12.3	15.9	15.9	n.a.
Enhanced oil recovery	1.5	1.3	1.5	1.8	2.2	2.7	1.4	3.1%
Natural gas liquids	7.8	12.7	14.8	15.9	16.8	17.7	5.0	1.4%
Unconventional	**1.4**	**5.0**	**10.4**	**12.5**	**14.2**	**15.0**	**10.0**	**4.9%**
of which light tight oil	0.0	2.0	4.7	5.7	5.9	5.6	3.6	4.7%
Total	**75.2**	**87.1**	**92.8**	**95.0**	**96.5**	**98.1**	**11.0**	**0.5%**

* Compound average annual growth rate. Note: The figures for production from existing fields are based on observed decline rates for conventional oil fields, *i.e.* it includes the effect of investment by operators to mitigate the decline in output.

14

Total production of conventional crude oil is projected to remain within a relatively narrow range over the projection period, falling slightly to 65 mb/d in 2035, compared with 69 mb/d today. This means that the share of crude oil in total oil production falls from 80% today to 67% in 2035 (Figure 14.8). Within this total, the amount coming from offshore fields is relatively constant, but the share of deepwater output rises from 7% in 2012 to 14% in 2035, reaching 9 mb/d in 2035 (see the focus on deepwater in the special section on Brazil, Chapter 11).

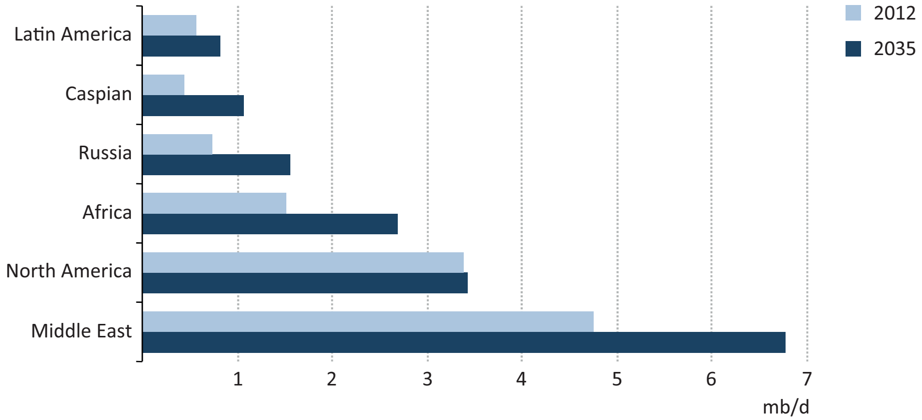
Figure 14.8 ▷ Shares of world oil production by type in the New Policies Scenario



The offshore Arctic is another frontier area with potentially large conventional oil resources (134 billion barrels of crude oil and NGLs [USGS, 2008]). A number of companies are pursuing exploration projects, for example, Shell in the Chukchi and Beaufort Seas; Cairn in offshore Greenland; Rosneft/ExxonMobil in the Kara Sea and Rosneft/ENI in the Russian Barents Sea. However, costs are high and environmental risks substantial. Given that alternative sources are available, less than 200 thousand barrels per day (kb/d) are projected to be produced from the offshore Arctic by 2035. Some developments could go faster, in particular those spearheaded by Russia, in partnership with international companies, in the Kara Sea and the Barents Sea, or by Norway in the Norwegian part of the Barents Sea.

With total crude oil production remaining at approximately today's levels, all of the growth in oil production comes from other sources. Chief among these is NGLs, production of which grows by almost 40%, to reach almost 18 mb/d by 2035 (Figure 14.9). By the end of the projection period, NGLs account for almost 20% of global oil production and become an increasingly influential factor both in gas and oil markets. Although sometimes considered a by-product of gas production, NGLs are often a major factor in upstream gas economics as companies increasingly target liquids-rich gas plays (see Chapter 3). NGLs provide a ready source of light oil products and their ever-growing supply has implications for the refining and petrochemicals sectors (examined in detail in Chapters 15 and 16).

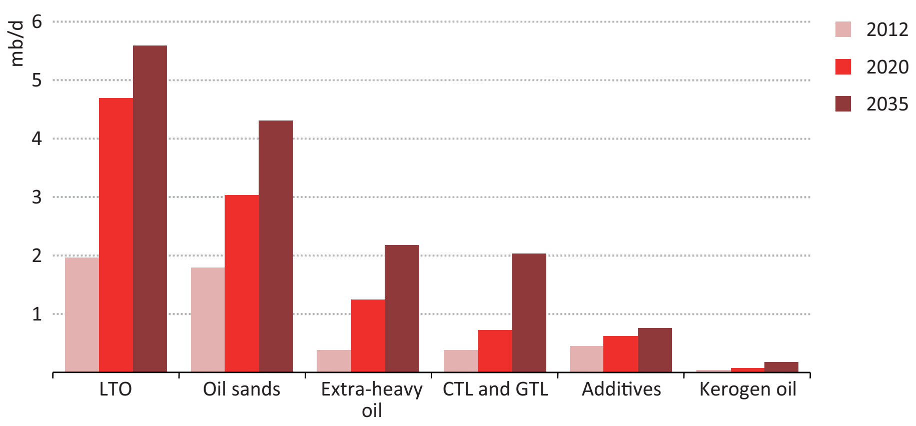
Figure 14.9 ▷ Production of NGLs in selected regions in the New Policies Scenario



Notes: NGLs production in North America grows significantly in the first half of the projection period, before falling to a level close to its 2012 value. This is linked to the expectation that the current focus on wet-gas plays will shift back to drier gas production as the gap between oil and gas prices closes to some extent and as depletion of wet-gas plays begins to increase costs.

Another source of production growth is unconventional oil, production of which rises from 5 mb/d in 2012 to 15 mb/d in 2035. These unconventional supplies come primarily from Canadian oil sands, LTO and extra-heavy oil in Venezuela (Figure 14.10). Rapid growth is also envisaged in GTLs output in the latter part of the projection period, with the largest volumes coming from Qatar and North America, and in CTLs production, primarily in China, with South Africa, Australia, Indonesia and the United States also contributing. Despite the size of the resource base, production of kerogen oil remains marginal, because of relatively high costs and environmental concerns.

Figure 14.10 ▷ Unconventional oil production in the New Policies Scenario



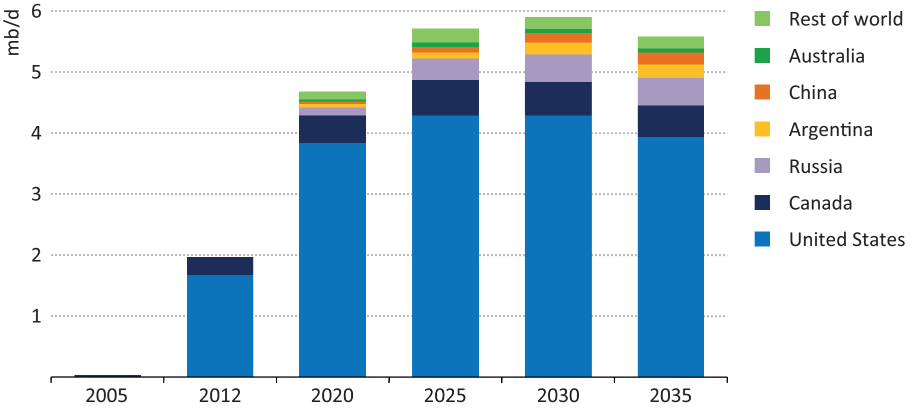
14

Focus on light tight oil

From close to zero in 2005, production of light tight oil (LTO) in the United States reached 2.3 mb/d by mid-2013, a turnaround that has been dramatic for the North American oil industry and, together with the growth in shale gas, has had profound effects across the international energy arena. In this section, we re-visit the projections for North America in the light of another year's worth of data from the main plays and new estimates of resources. We also look at the potential for LTO production outside the United States, in particular in three countries that have been estimated by the US Energy Information Administration to have the largest resource potential: Russia, China and Argentina (see Chapter 13).

Overall, it is anticipated that North America – the United States with a smaller contribution from Canada – will continue to dominate global LTO output (Figure 14.11). The upward revision in the resource estimate for the United States means that the projections see a higher plateau for LTO production and one that is sustained for longer, compared with *WEO-2012*. Elsewhere, most countries struggle to replicate the North American experience at scale: LTO production in 2035 reaches 450 kb/d in Russia, 220 kb/d in Argentina and 210 kb/d in China, but elsewhere stays in the tens of thousands of barrels per day. Regulatory barriers and the absence in most countries of a strongly competitive and innovative upstream environment tend to keep production costs above the levels at which significant investments are forthcoming (economies of scale are important in achieving competitive production costs). Tight oil production technologies do, though, have a somewhat wider impact than the LTO output numbers alone would suggest: the multi-stage hydraulic fracturing in horizontal wells techniques that have been the key to LTO and shale gas developments are now beginning to be deployed in more conventional fields as well. Their use is set to increase in a way that extends the life and yields of some lower quality conventional plays (Box 14.3).

Figure 14.11 ▷ LTO production in selected countries in the New Policies Scenario



Sources: IEA databases and analysis; Rystad Energy AS.

Box 14.3 ▷ Will LTO techniques improve recovery at conventional reservoirs?

Hydraulic fracturing generally increases production rates in all the reservoirs it can be applied to (though, if practised near water or gas zones, this may mean faster breakthrough of water or gas production). The question is whether the improved production rate provides sufficient payback for the cost of the operation. Single hydraulic fracturing stages are fairly commonly applied to conventional wells, to improve the flow where permeability is low. However the type of intensive multi-stage fracturing that is applied to shale reservoirs is expensive and is generally considered economically viable only where there is sufficient scale (and thus high equipment utilisation rates) to bring the costs down.

As such it is reasonable to imagine that in basins such as the Permian in Texas, where activity levels ensure that wells can be treated with multi-stage fracturing relatively inexpensively, the techniques will be applied to conventional plays, as well as to shale plays, increasing the overall economically recoverable resources in some ageing conventional reservoirs. This could potentially unlock more conventional resources globally, in areas where the scale of unconventional developments has reduced the cost of the services. Other possibilities are very large fields with small recovery factors, such as Chicontepec in Mexico or some mature fields in Russia.

LTO outlook for North America

As highlighted in the earlier analysis, a feature of LTO resource development is the rapid decline in oil output at each well, with most of the oil from a single well produced in the first few years. For this reason, increasing production of LTO – or sustaining a significant level of output – requires continuous investment in drilling new wells to compensate for decline at existing ones. What counts is the number of rigs in operation, how quickly these rigs can drill a well and how productive these wells are before decline sets in. In most plays in the United States, these indicators continue to improve year-on-year, with the LTO rig count increasing, and drilling costs and time decreasing.

For the moment, LTO production in the United States is concentrated on tight rock formations in North Dakota (Bakken) and Texas (Eagle Ford and the plays in the Permian basin). The Bakken is the largest continuous oil accumulation that the US Geological Survey (USGS) has ever assessed. When considered together with its neighbouring Three Forks play, it covers an area larger than the size of France. The North Dakota part of the Bakken was producing more than 800 kb/d as of July 2013 and had not yet reached its plateau production level, which is anticipated to be in excess of 1 mb/d. The rate of month-on-month growth in output is slowing: as production increases, it takes more and more wells to offset the decline in already drilled wells. Indeed, the ratio of incremental production to the number of new wells drilled has been falling in the first half of 2013. We estimate that maintaining Bakken production at 1 mb/d (after it reaches that level) will require drilling around 2 500 new wells per year (for comparison, maintaining output of 1 mb/d at a large conventional field in, for example, southern Iraq, would require only around 60 wells per year). With 6 000 currently producing wells in the Bakken (at mid-2013) and an estimate of around 40 000 further possible well locations, a plateau lasting a dozen years is possible.

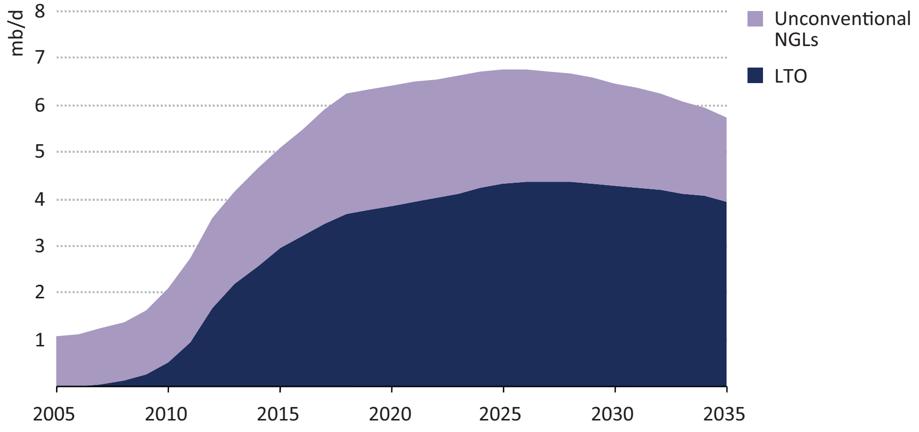
There is for the moment no sign that output at the main LTO plays in Texas has reached the point at which it would start to flatten out. Even though activity levels at the Eagle Ford play have been flat over the last year (in terms of the number of wells drilled and the number of hydraulic fracturing stages completed), there has still been consistent growth in production levels, which were above 600 kb/d at mid-2013. Efficiency gains have meant that each rig in the Western Gulf basin, where the Eagle Ford play is located, is now drilling an average of one well per month, a 30% improvement over the average for 2012. Production in the Eagle Ford exceeds that in the Bakken by 2015. Elsewhere in Texas, LTO output from the Permian basin (a well-established conventional oil and gas province) has risen sharply, to reach 500 kb/d by mid-2013.

Beyond these three large-scale areas, another half-dozen tight oil plays are currently being investigated in various parts of the United States. In aggregate, these and the other plays already discussed are set to maintain LTO output at the projected plateau level of around 4.3 mb/d between 2025 and 2030, with a slight drop by 2035 (Figure 14.12). It is, though, still too early to speak with confidence about the trajectory for LTO production in the United States: performance has consistently overshot most projections to date and it is possible that more resources will be found and developed to sustain production at a higher level and for longer than we project, especially if oil prices hold up, technology advances continue and environmental concerns are allayed.

There are also downside risks. Resources in some of the new plays could be more difficult to access or expensive to produce and there is certainly no guarantee that each of the plays will be as prolific as the Bakken or Eagle Ford. The Utica shale in Ohio, for example, initially seen as promising, turned out to produce mostly gas, rather than oil (possibly because the oil it contains is not mobile); it produced only 700 000 barrels of oil in total in 2012, less than one day's production from the Bakken. Production could also be constrained by limitations in the supply chain or in downstream infrastructure, although in most cases these would result in delays, rather than resources being left in the ground. There are also social and environmental concerns, very similar to those for shale gas development. These need to be properly addressed if curbs on upstream activity are to be avoided. Finally, there is the possibility that oil prices will fall to a level at which production is no longer economic. Most estimates put the breakeven price of tight oil production in the United States at between $60-80/barrel, so it would take only a relatively modest fall in the price to affect production prospects at the higher end of this range. In any event, United States light tight oil production starts to decline in the last five years of the projection period, as drilling locations for the "sweet spots" in the key shale plays run out and activity moves to less productive zones, which struggle to compete in terms of cost, with other sources of oil from other countries.

North American LTO production is bolstered in the projections by output from Canada, which rises from low levels today to reach 600 kb/d by 2027, before declining slightly to 500 kb/d in 2035, following a trend similar to that of the United States. Compared with its southern neighbour, Canada is in the early stages of developing its tight oil resources, with a focus on the northern part of the Bakken play (which extends across the border) and on parts of British Columbia (the Montney play, which also extends into Alberta), the Duvernay and Cardium formations in Alberta and the Viking play in Alberta and Saskatchewan. The latter four are predominantly liquid-rich gas plays, but they also contain some oil.

Figure 14.12 ▷ Projected LTO and NGLs production from unconventional plays in the United States in the New Policies Scenario



In addition to LTO, there is also rapidly growing production of NGLs from shale gas plays in the United States (Figure 14.12). In fact, the boundary between LTO and liquid-rich shale gas is more and more blurred. LTO plays often produce large amounts of associated gas (up to one-third of which, in the case of the Bakken play, is currently flared because of a lack of means to bring it to market) and, conversely, in liquid-rich shale gas plays, the liquids often completely drive the economics. A complex interplay between geology and economics can determine which is targeted. For example in the Eagle Ford, the oil zone tends to be shallower and well costs are lower than in the wet-gas zone, but lower pressure leads to smaller liquid production rates (as production is driven by the natural pressure in the reservoir). Towards the end of the projection period, production of NGLs in the United States flattens and begins to decrease, as activity gradually shifts back to drier gas plays, driven by the improved gas-to-oil price ratio and increasing depletion of the wet-gas plays.

LTO outside North America

As with shale gas, the experience in the United States has alerted other potential LTO resource-holders worldwide. Companies and governments are looking for similar geological conditions, where an abundant source rock is both rich in hydrocarbons and brittle, lending itself to fracturing techniques to extract the oil. However, only very preliminary estimates of potential resources are available and there is essentially no experience of production nor basis for economic appraisal. As a result, the projections remain modest, though production could grow much faster. Among the most promising areas geologically are the Neuquen basin in Argentina, the Bazhenov shale in Russia and parts of China and the Middle East, although the abundance of easily accessible conventional resources in the Middle East makes it less likely that the unconventional oil will be developed.

Good geology alone is not sufficient to replicate the US experience – it will also take a regulatory environment and an oilfield service capacity able to match the scale of operations, bring operational efficiencies and make the developments economic. Outside North America, these factors are by and large not yet in place. Governments are still studying suitable regulatory and fiscal regimes. For the moment, the scale of activity is insufficient even to enable the trial-and-error learning that is necessary to determine the right well-completion design for each play, let alone to achieve the economies of scale that are needed to make production profitable. Over 6 000 wells were drilled for tight oil in the United States and Canada in 2012, and only 100 outside North America.

Not surprisingly, we are seeing the first wave of non-US LTO activity in countries with a history of oil and gas production, existing infrastructure and well-developed supply chains. Of the countries that are looking at light tight oil potential, most also have shale gas potential. Only Argentina and Russia have indicated that their prime focus is oil, whereas in the others, such as Australia, Algeria or China, the indications are that unconventional gas will take priority.

In Argentina, activity is focusing on the Vaca Muerta shale in the Neuquén basin, one of the most significant LTO plays so far identified outside the United States. YPF announced potential resources of 7 billion barrels in February 2012 (YPF, 2012). Initial wells have given flow rates that indicate that the play could be produced economically (albeit at higher costs than US plays).[15] Argentina has a clear imperative to develop tight oil: the country used to be an exporter but is now an importer of oil. The Neuquén basin is an established oil and gas province with a long history of production meaning that relevant expertise and some infrastructure are available. The key uncertainty lies in the regulatory framework and the need for security for the large investments required (worries exacerbated by expropriation of Repsol's assets in 2012, though the recent agreement between YPF and Chevron for joint exploitation in the Vaca Muerta indicates that some international investors may not be deterred).

LTO is an increasingly important subject of discussion also in Russia. The Bazhenov shale, the main source rock for the western Siberian conventional oil reservoirs, has high potential and, although other geographical areas and geological layers could be rich in LTO, the Bazhenov is likely to be the main focus. It is rich in organic content and there are indications that it is also suitably brittle. Resource estimates vary widely, in part because the extent of the deposit is so large that it is unlikely ever to be fully

15. At mid-2013, YPF was producing about 10 kb/d for LTO in Vaca Muerta; the wells tested at average initial rates of between 200 b/d and 560 b/d.

developed. Activity is likely to concentrate close to currently exploited conventional reservoirs, where infrastructure and industry capabilities are in place. Extending the life of the western Siberian oil towns is an objective for both the government and the industry, as the conventional reservoirs in the region are ageing rapidly. GazpromNeft has reported promising well-test results in the Bazhenov, both from its own wells and in wells operated by the joint venture with Shell, Salym Petroleum Development. Several of the major Russian oil companies are actively investigating the potential of the Bazhenov in their respective license areas.

In addition to the scale of the potential developments, taxation levels will be a key determinant of the level of future Russian LTO production: the normal mineral extraction tax (MET) and export tax basically require full-cycle production costs to be below $25/barrel, an unlikely level for most LTO resources. At the end of July 2013, the MET was suppressed for selected LTO formations for the first fifteen years of production (and partial MET exemptions given to some other "hard-to-produce" resources). The Russian Ministry of Energy has estimated potential output from the Bazhenov under this new tax regime at between 800 kb/d and 2 mb/d by 2020. The projections are much more conservative at only 450 kb/d in 2035, pending evidence from production tests and economic appraisal.

There are many reasons to be optimistic about LTO production in China in the long term. Strong market demand is likely to drive the country to find a way to exploit its resources. And China, perhaps more than any other country outside the United States, has the potential to bring costs down by maximising the use of locally built equipment and through economies of scale: with about 1 200 active units, its fleet of drilling rigs is second only to that of the United States. Although China has not specifically assessed nor targeted its shale LTO resources (with less than 20 wells drilled so far), it has experience in producing from low-permeability reservoirs: about one-quarter of Chinese oil production is reported to come from low-permeability fields, requiring traditional hydraulic fracturing or horizontal wells. Some wells are reported to have used a limited number of hydraulic fracturing stages in horizontal wells. But China also faces many obstacles: high population density in some areas, water scarcity in others, lack of competition (as the three state-owned oil companies automatically have exclusive rights to oil resources and are currently focused entirely on conventional resources) and a relatively high cost structure in most parts of the country, even for conventional developments. This is why current projections remain conservative.

Oil production by region

Non-OPEC

In the New Policies Scenario, non-OPEC production maintains the upward trajectory of recent years through to around 2020, but then levels off and begins to tail away from the late-2020s. By 2035, output is still around 3.5 mb/d higher than in 2012. In the early part of the projection period, output of both conventional and unconventional oil expands, but the former peaks already before 2020 and, within a few years, its decline outpaces the growth in unconventional oil, which slows. Total oil production falls between 2012 and

2035 in the majority of non-OPEC countries, the principal exceptions being Brazil, Canada, Kazakhstan and the United States (though US production is in decline before the end of the projection period).

As described, oil output in the *United States* is undergoing a renaissance, thanks mainly to spectacular growth in LTO, and this is expected to continue. On the assumption that Saudi Arabia reins back production levels in its capacity as the swing producer within OPEC, this means that the United States becomes the largest oil producer in the world (including crude, NGLs and unconventional oil) by 2015 and retains this status until the beginning of the 2030s. Growing output of LTO, NGLs and gas- and coal-to-liquids is sufficient to more than offset dwindling output of US conventional crude oil until late in the projection period.

Across the border in *Canada*, oil production grows steadily through the projection period, with rising output from oil sands and light tight oil more than making up for a slow decline in conventional crude oil. In total, output rises by 62%, from 3.8 mb/d in 2012 to 6.1 mb/d in 2035. Oil sands produce 4.3 mb/d in 2035, up from 1.8 mb/d in 2012, with their share of overall oil production rising from just under half to 70%. While the resources are unquestionably large enough to support such an expansion, achieving it is contingent on the construction of major new pipelines to enable the crude to be exported to Asia and the United States. Two pipelines from the oil sands in Alberta to the Pacific Coast have been proposed – the 530-kb/d Northern Gateway line to Kitimat and the expansion, from 300 kb/d to 890 kb/d, of the Trans Mountain line to Vancouver – as well as the Keystone XL line to the United States. The first two projects require provincial and federal approval (the environmental review process for the Northern Gateway is expected to be complete at the end of 2014), while the Keystone XL line is awaiting approval from the US government. The US administration indicated in June 2013 that the project would be approved only if it does not “significantly increase” greenhouse-gas emissions. In the meantime, transport of Canadian oil by rail has increased dramatically, though the major rail accident that occurred in July 2013 in Quebec might slow it down. Export routes from the east coast of Canada are also being explored.

Mexico has recently managed to halt the sharp plunge in oil production that started in the mid-2000s. Output from new fields, notably Ku/Maloob/Zaap, was able to offset the drop in supply from mature fields, including the super-giant Cantarell field, which has seen its production drop from a peak of over 2.1 mb/d in 2003-2004 to barely 400 kb/d today. Production is projected to stabilise at around current levels over the *Outlook* period, though much will depend on progress in pushing through the much-needed reforms in the oil sector promised by the new president. The monopoly of the national oil company, Pemex, over all hydrocarbon resources in Mexico has stifled investment and innovation. The constitutional reform proposed in August 2013, if adopted, could facilitate private investment and unleash significant production growth (see later Low Oil-Price Case section).

Table 14.5 ▷ Non-OPEC oil production in the New Policies Scenario (mb/d)

	1990	2012	2020	2025	2030	2035	2012-2035 Delta	2012-2035 CAAGR*
OECD	**19.0**	**19.9**	**23.2**	**23.1**	**22.8**	**22.4**	**2.5**	**0.5%**
Americas	13.9	15.9	19.3	19.8	19.9	19.6	3.8	0.9%
Canada	2.0	3.8	5.0	5.3	5.7	6.1	2.3	2.1%
Mexico	3.0	2.9	2.7	2.6	2.6	2.6	-0.3	-0.4%
United States	8.9	9.2	11.6	11.8	11.5	10.9	1.7	0.7%
Europe	4.3	3.5	3.1	2.6	2.2	2.0	-1.5	-2.3%
Asia Oceania	0.7	0.6	0.7	0.7	0.7	0.7	0.2	1.1%
Non-OECD	**22.7**	**29.5**	**31.9**	**32.0**	**31.4**	**30.6**	**1.0**	**0.2%**
E. Europe/Eurasia	11.7	13.8	13.7	13.7	13.9	14.2	0.4	0.1%
Kazakhstan	0.5	1.6	1.9	2.5	3.2	3.7	2.1	3.6%
Russia	10.4	10.7	10.4	9.9	9.6	9.4	-1.3	-0.6%
Asia	6.0	7.8	7.7	7.4	6.8	6.0	-1.8	-1.1%
China	2.8	4.2	4.4	4.3	4.1	3.4	-0.8	-0.9%
India	0.7	0.9	0.8	0.7	0.7	0.6	-0.3	-1.7%
Middle East	1.3	1.5	1.3	1.1	1.0	0.9	-0.6	-2.2%
Africa	1.7	2.3	2.9	2.6	2.3	2.1	-0.2	-0.4%
Latin America	2.0	4.2	6.2	7.2	7.4	7.4	3.2	2.5%
Brazil	0.7	2.2	4.1	5.4	5.8	6.0	3.8	4.5%
Total non-OPEC	**41.7**	**49.4**	**55.0**	**55.1**	**54.2**	**52.9**	**3.5**	**0.3%**
Non-OPEC market share	*64%*	*57%*	*59%*	*58%*	*56%*	*54%*	*n.a.*	*n.a.*
Conventional	**41.3**	**45.0**	**46.2**	**44.6**	**42.6**	**40.7**	**-4.3**	**-0.4%**
Crude oil	37.6	38.4	38.3	36.4	34.3	32.3	-6.1	-0.7%
Natural gas liquids	3.6	6.6	8.0	8.1	8.3	8.3	1.7	1.0%
Unconventional	**0.4**	**4.4**	**8.8**	**10.5**	**11.7**	**12.3**	**7.9**	**4.6%**
of which:								
Canada oil sands	0.2	1.8	3.0	3.3	3.8	4.3	2.5	3.9%
Light tight oil	0.0	2.0	4.7	5.7	5.8	5.5	3.6	4.6%
Coal-to-liquids	0.1	0.2	0.4	0.7	0.9	1.2	1.0	8.3%
Gas-to-liquids	0.0	0.1	0.1	0.2	0.3	0.4	0.4	9.9%

* Compound average annual growth rate.

The long-term decline in oil output in Europe continues apace, with overall production in OECD countries dropping by 300 kb/d in 2012, to under 3.5 mb/d, down 3.3 mb/d on the peak in 2000. Production is set to slide further through the projection period, in spite of slightly rosier medium-term prospects in the *United Kingdom*, following recent investment-friendly tax measures, and developments in *Norway*, where exploration successes have raised hopes of stemming the projected decline in output.

Oil production in *Russia* is approaching the record levels of the Soviet era, but maintaining this trend will be difficult, given the need to combat declines at the giant western Siberian fields that currently produce the bulk of the country's oil. Output climbed 130 kb/d in 2012 to a post-Soviet high of 10.7 mb/d and is projected to stay close to this level until the end of the decade. Thereafter, Russia's success in combating a declining trend in crude output will depend on four factors: success in raising recovery rates at existing conventional fields; the related issue of developing Russia's unconventional oil (these first two challenges are often grouped together in Russian debates and in fiscal policy as "hard-to-recover" oil); the continued expansion into new onshore production areas, for example in eastern Siberia; and, for the longer term, the prospect of output from the Arctic offshore. Success in each of these areas depends on supportive fiscal conditions and, in the case of the Arctic at least, successful partnerships with international companies. In the projections, efforts in these areas are not sufficient to keep oil output above the 10 mb/d level beyond 2025 and Russian oil production slips to around 9.5 mb/d by 2035.

In *Kazakhstan*, the main sources of production growth over the projection period are the Kashagan, Tengiz and Karachaganak fields. After years of delay, Kashagan – the largest conventional field discovered worldwide in the last 30 years – is finally set to begin producing significant volumes in 2014, as production from the first phase of the project ramps up. The timing and size of the second phase of development, which is planned to raise production towards 1 mb/d, remains highly uncertain. It is assumed that this starts, at the earliest, in the mid-2020s. Further increases in condensate production from Karachaganak and crude output from Tengiz are planned, but they require expanded transport capacity in order to ship the liquids to export markets. Total Kazakh oil production is projected to climb from 1.6 mb/d in 2012 to 1.9 mb/d in 2020 and 3.7 mb/d in 2035.

The majority of the projected increase in oil production in Latin America comes from *Brazil*, driven in large part by the development of the country's massive offshore pre-salt deposits that have been found in recent years (see Chapter 11 for a detailed discussion of Brazilian oil prospects). Among the other non-OPEC countries, prospects for production in *Colombia* have brightened alongside improvements in the security situation and regulatory framework. Output from the established Rubiales heavy oil field continues to grow, having reached more than 250 kb/d in early 2013. Yet the country's production, which should hit 1 mb/d in 2013, is still expected to peak within the current decade at close to 1.2 mb/d and then to fall over the longer term to around 0.5 mb/d in 2035, as mature fields decline. No major field has been found in recent years, despite increased exploration activity. There is potential for light tight oil developments, but these are early days and the economics have yet to be established. Elsewhere in the region, production peaks and then drops in *Peru* and *Bolivia*, despite efforts to attract more investment, as well as in *Argentina*. In Argentina, NGLs associated with shale gas and light tight oil rise, but production is not sufficient to offset the decline in conventional crude oil production from mature fields in the Neuquén region. Overall production drops from 675 kb/d in 2012 to 550 kb/d in 2035.

Production among the non-OPEC African countries diverges, with mature producers, such as Egypt, Chad and Gabon, seeing declines over the projection period, while output takes off in some countries of East Africa and West Africa. East Africa has become a hotspot of exploration and development activity, with the discovery of major new deposits in recent years in offshore Tanzania, Uganda and – most recently –onshore Kenya; but how much and how soon these fields will start producing remains very uncertain. While most of the existing producers in West Africa have met with limited success in finding more conventional oil, exploration into deepwater pre-salt formations – geologically similar to those to the west offshore Brazil – is underway all along the West African coast and could bring new discoveries. Morocco could also see production rise over the *Outlook* period as a result of increasing exploration activity. In aggregate, non-OPEC African output is projected to rise modestly over the next decade, before falling back to just below current levels by 2035. Among the other main non-OPEC Middle East producers, Oman and Yemen are both expected to see production declines before 2035. Jordan could see moderate growth, if it gets the long-discussed kerogen oil projects under way.

Our revised recoverable resources number for *China* (coming from the USGS updates) is sufficient to enable the country to maintain production above 4 mb/d until at least 2030, before decline at its mature workhorse fields, including the super-giant Daqing field, takes over. This is consistent with the Chinese government target of maintaining production at the current level in the long term. Supplies from new light tight oil deposits and CTL plants are projected to grow (one CTL plant is already operating). In *Australia*, soaring NGLs supplies resulting from the big expansion of gas production and the emergence of an unconventional oil industry (LTO, CTL and/or kerogen oil) compensate for dwindling crude oil production, bringing production to a plateau of around 600-700 kb/d over the *Outlook* period.

OPEC

The projected growth in output by OPEC countries comes mainly from the Middle East, which sees its production rise by about 7 mb/d between 2012 and 2035, compared with less than 1 mb/d in OPEC countries outside this region. Middle East OPEC countries have the biggest conventional resource endowments and generally benefit from the lowest development costs in the world, thanks to favourable geology and access to established infrastructure. They could increase production even more (as projected in the Current Policies Scenario), but short-term market management policies and long-term depletion policies are likely to continue to hold back investment.

The increase in overall OPEC production to 2035 is lower than projected in *WEO-2012*, mainly because of stronger growth in non-OPEC supplies. NGLs are the biggest contributor to OPEC production growth, accounting for more than 3 mb/d of the increase, 50% more than the rise in crude oil output. Venezuelan extra-heavy oil accounts for most of the rest. Large GTL plants in Qatar and Nigeria, as well as small-scale GTL in other countries, make a minor contribution.

Table 14.6 ▷ OPEC oil production in the New Policies Scenario (mb/d)

	1990	2012	2020	2025	2030	2035	2012-2035 Delta	2012-2035 CAAGR*
Middle East	**16.4**	**26.7**	**27.3**	**29.2**	**31.1**	**33.6**	**6.9**	**1.0%**
Iran	3.1	3.5	3.3	3.6	3.8	4.2	0.7	0.8%
Iraq	2.0	3.0	5.8	6.7	7.3	7.9	4.9	4.3%
Kuwait	1.3	3.0	2.4	2.5	2.7	2.9	-0.1	-0.1%
Qatar	0.4	2.0	2.0	2.2	2.4	2.6	0.6	1.1%
Saudi Arabia	7.1	11.7	10.6	10.9	11.4	12.2	0.5	0.2%
United Arab Emirates	2.4	3.5	3.3	3.3	3.5	3.7	0.3	0.3%
Non-Middle East	**7.5**	**11.0**	**10.5**	**10.7**	**11.2**	**11.6**	**0.6**	**0.2%**
Algeria	1.3	1.8	1.7	1.7	1.7	1.8	0.1	0.1%
Angola	0.5	1.9	1.6	1.5	1.4	1.4	-0.4	-1.2%
Ecuador	0.3	0.5	0.4	0.3	0.3	0.3	-0.2	-2.3%
Libya	1.4	1.5	1.6	1.7	1.8	1.9	0.4	1.1%
Nigeria	1.8	2.6	2.4	2.5	2.6	2.8	0.2	0.3%
Venezuela	2.3	2.7	2.8	3.0	3.3	3.3	0.6	0.9%
Total OPEC	**23.9**	**37.6**	**37.8**	**39.9**	**42.2**	**45.2**	**7.5**	**0.8%**
OPEC market share	*36%*	*43%*	*41%*	*42%*	*44%*	*46%*	*n.a.*	*n.a.*
Conventional	**23.9**	**37.0**	**36.2**	**37.9**	**39.7**	**42.4**	**5.3**	**0.6%**
Crude oil	21.9	30.9	29.4	30.1	31.2	33.0	2.1	0.3%
Natural gas liquids	2.0	6.1	6.8	7.8	8.5	9.3	3.2	1.9%
Unconventional	**0.0**	**0.6**	**1.6**	**2.0**	**2.5**	**2.8**	**2.2**	**6.9%**
of which:								
Venezuela extra-heavy	0.0	0.4	1.2	1.5	1.9	2.1	1.7	7.5%
Gas-to-liquids	0.0	0.1	0.2	0.3	0.4	0.4	0.3	5.1%

* Compound average annual growth rate. Notes: Data for Saudi Arabia and Kuwait include 50% each of production from the Neutral Zone.

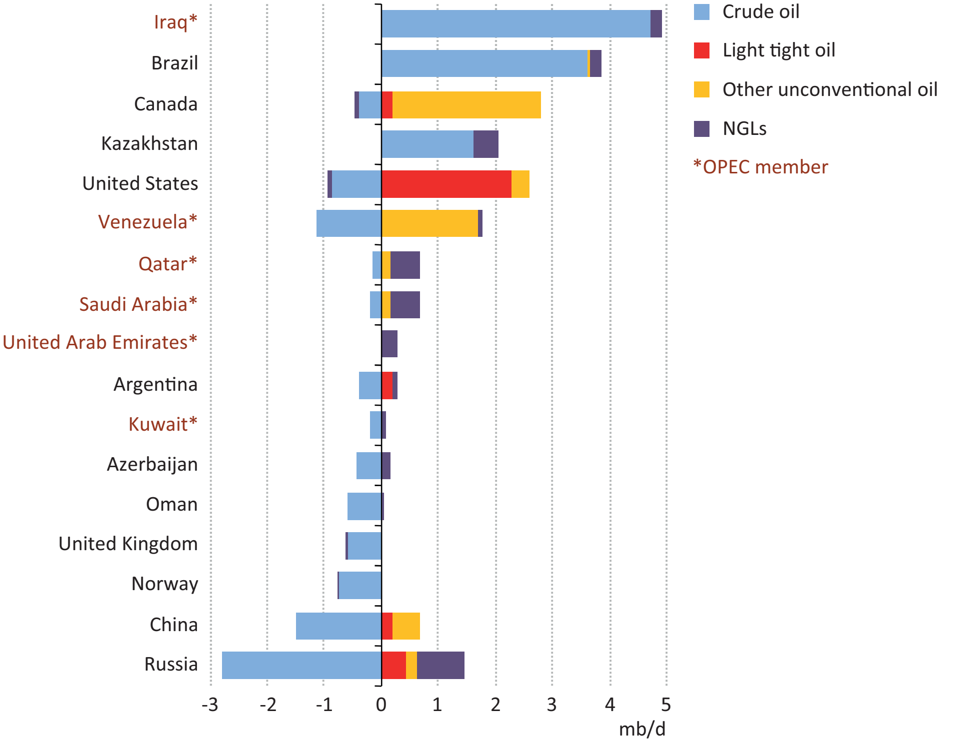
Saudi Arabia is the world's biggest oil producer and holds the largest conventional oil reserves in the world, sufficient to underpin high levels of production for decades to come. Official policy is to maintain crude oil production capacity at 12.5 mb/d – about 500 kb/d above the current level – and to have available spare capacity of at least 1.5-2 mb/d (it averaged 2.2 mb/d in 2012). Several major projects are currently underway to ensure such capacity is sustained: the development of the 900-kb/d offshore Manifa heavy oilfield, which produced first oil in spring 2013 and is due to be completed in 2014; the expansion of the Khurais and Shaybah onshore fields; and the redevelopment of the Zuluf and Berri fields offshore. A decision is due at the end of 2013 on whether to proceed with steam injection to boost heavy oil production at the Wafra field, shared with Kuwait, in the Neutral Zone. The project, led by Chevron, would be the largest of its kind. Meanwhile, the drilling effort needed to sustain output at existing fields, including Ghawar, the world's biggest, is rising as they age. Saudi Aramco has been gradually increasing the number of drilling rigs in the country and this is expected to continue. Ghawar still accounts for more than half of the country's crude oil production. In the projections, Saudi Arabia remains the largest exporter of oil throughout most of the period, though it is tied with Russia between 2015 and 2020, a time when we project that OPEC will limit output in the light of the growing North American LTO production.

Iraq makes the largest contribution to OPEC (and worldwide) supply growth (Figure 14.13), its production rising from 3.0 mb/d in 2012 to 7.9 mb/d in 2035, 0.4 mb/d lower than projected last year, as progress on the ground in the last year has been slower than expected. The plateau production targets for two of the main southern fields have been renegotiated downwards from the initially agreed levels: for the West Qurna field, from 1.8 mb/d to 1.2 mb/d, and for Zubair, from 1.2 mb/d to 850 kb/d. But plateau production is now due to last for longer (and the duration of the technical service contracts has been extended accordingly). Similar discussions with other operators are reportedly underway, in line with the downward revision of Iraq's official production targets. In the *Outlook*, a range of hurdles, including persistent security concerns, infrastructure constraints and logistical difficulties, continues to constrain the rate of growth over the current decade, with production reaching 5.8 mb/d in 2020.

The outlook for production in *Iran* remains highly uncertain in view of the international sanctions imposed on the country in response to its nuclear programme. Production fell to 3.5 mb/d in 2012 and crude production (excluding NGLs) reportedly dropped to just 2.6 mb/d in mid-2013 – the lowest level in more than twenty years – as the country's main customers reined in their purchases because of the sanctions. A lack of access to technical expertise and equipment, and under-investment have, in any case, reduced capacity, while rising domestic gas demand, especially for power generation, is also restricting the availability of gas for reinjection into oilfields to sustain flow rates. The government is reportedly preparing revisions to its unsuccessful buyback contracts and may consider production-sharing contracts; but interest is expected to be weak until political uncertainty recedes. In June 2013, the government announced that it had offered a production-sharing contract to Indian investors to develop a block in the offshore Farzad-B gas field – the first such contract since the 1979 Iranian revolution. Oil production is projected to remain low in the coming years as it will take time to rebuild capacity even if sanctions are loosened or lifted soon. Production recovers slowly after 2020, to 4.2 mb/d in 2035, on the assumption that the current international stand-off is resolved.

In the *United Arab Emirates*, Abu Dhabi – the leading producer – is discussing the conditions of the new concessions that will replace its 75-year concession agreement with the Abu Dhabi Company for Onshore Oil Operations (ADCO, a joint venture with international companies), which is expiring soon (two other, offshore, concessions will expire in 2018 and 2026). The new concessions are likely to involve conditions to bolster investment in output at the country's mature fields, notably Upper Zakum and Bab, and to develop new deposits, including Qusahwira. Abu Dhabi holds the bulk of United Arab Emirates' oil reserves, which rank seventh in the world, but production growth increasingly relies on the deployment of improved oil recovery techniques. The government recently pushed back its target date for crude oil production capacity of 3.5 mb/d from 2017 to 2020, because of delays in some of the upstream projects and in awarding development contracts, including for Upper Zakum. For the United Arab Emirates as a whole, total oil production, including NGLs, is projected to edge higher from 3.5 mb/d in 2012 to 3.7 mb/d in 2035.

Figure 14.13 ▷ Change in oil production in selected countries in the New Policies Scenario, 2012-2035



Kuwait's oil production prospects continue to depend on the political acceptability of the participation of international companies, which have the expertise to develop the country's heavy oil deposits in order to offset stagnating output at mature fields. Kuwait is still officially targeting an expansion of overall oil production capacity from 3.2 mb/d today to 4 mb/d by 2020, though delays in signing agreements with foreign companies have made meeting that target unlikely. For example, Shell's project in gas condensate fields in the north of the country was meant to add 350 kb/d of light oil and condensate capacity by 2020, but less than half of that may be available by then. The country's total oil output, including NGLs, remains around current levels throughout most of the projection period (after an initial drop when the call on OPEC is reduced in the coming few years).

In *Qatar*, all of the projected 550-kb/d growth in oil production to 2.6 mb/d between 2012 and 2035 comes from NGLs and GTL, underpinned by a continuing expansion of gas production and LNG exports. A new round of LNG projects is expected to be undertaken in the 2020s, on the assumption that the current moratorium on development of the North Field – the world's largest conventional gas field – is lifted later in the current decade (see Chapter 3). It is also assumed that new GTL projects are sanctioned, boosting nameplate capacity to around 400 kb/d from 174 kb/d at present (34 kb/d at the Oryx plant, commissioned in 2007, and 140 kb/d at Pearl GTL, completed in 2012). These capacity additions are expected to offset a decline in crude oil production. Several production sharing agreements with international companies will expire soon and the new deals are expected to see the national company, Qatar Petroleum, take bigger stakes. Access to international technological expertise will be crucial in arresting sliding production at the country's mature fields, including the offshore Al-Shaheen field, where Maersk has agreed a new plan to raise output, previously targeted at 525 kb/d.

Prospects for oil production in the sub-Saharan OPEC countries in the longer term depend both on the extent of civil unrest and political instability in Nigeria, and on the discovery and development of major new deposits, the best hope for which probably lies in pre-salt formations. In *Nigeria*, theft and attacks on oil facilities continue to disrupt onshore and shallow water production, though output received a boost in 2012, with the start-up of the 160-kb/d deepwater Usan field. Other offshore developments are proceeding slowly, largely as a result of uncertainty over the fiscal and royalty terms under the long-awaited Petroleum Industry Bill, which is still in preparation. We project a slight decline in production through to 2020 and a modest recovery thereafter to about 2.8 mb/d in 2035, assuming the requisite investment materialises, most of which will need to come from abroad. *Angola*'s deepwater production is set to rise in the near term, with the completion of BP's Saturno development, as well as satellite projects at the Clochas and Mavacola fields, which should offset small declines at the mature Girassol field – the country's biggest. In the absence of major new discoveries, output is expected to edge lower in the longer term, reaching 1.4 mb/d in 2035. But this bearish outlook could be transformed if ongoing exploration drilling proves up large pre-salt reserves. Non-OPEC Gabon, to the north, has already made commercial discoveries of pre-salt oil.

Both North African OPEC members, Libya and Algeria, will struggle to boost production capacity over the longer term unless they step up exploration. In *Algeria*, output has been on the slide for several years, mainly because of declines at old fields that have been in production for decades, insufficient exploration drilling and dwindling discoveries. The terrorist attack on the In Amenas gas complex in January 2013 has further undermined industry confidence and augurs ill for future investment. The government announced in 2013 that it will reform the 2005 Hydrocarbons Law, to introduce tax incentives for foreign investment, and will raise Sonatrach's capital budget for the next five years to $80 billion. We project production to remain around current levels through to 2035, in part due to offshore and unconventional developments.

In *Libya*, production rebounded in 2012, to around 1.5 mb/d – close to pre-conflict levels – but a return of insecurity and political instability in 2013 is clouding the near-term outlook. Longer-term prospects hinge on developing a larger part of the reported reserves and the new government is planning a licensing round covering new onshore and offshore zones later in 2013, but the terms are not yet known. We project that production will remain around the levels seen in early 2013, prior to the latest unrest, for the rest of this decade, before starting a modest rise through to 2035 on the assumption of increased political stability and increased investment.

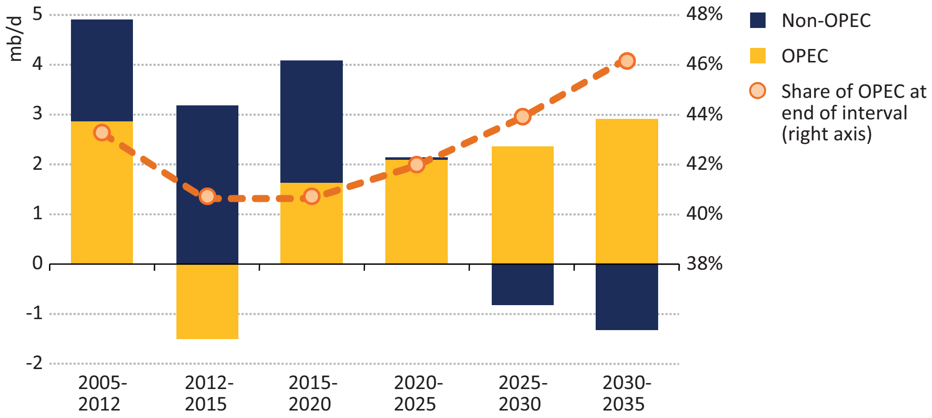
Venezuela holds the largest oil reserves in the world, made up primarily of unconventional extra-heavy oil in the Orinoco Belt. Production has slumped in recent years, due to a lack of investment by the national oil company, PDVSA, and policies that have discouraged foreign investment. There are few signs of a change of course under the newly-elected president and, given that PDVSA revenues are a vital source for government expenditure, the squeeze on funds available for investment is likely to continue, making a rapid reversal in declining crude oil and NGLs production unlikely. Over the medium to long term, rising extra-heavy oil output is projected to outweigh weak conventional production thanks to large-scale projects, most of which are undertaken in partnership with international companies. Total output reaches 3.3 mb/d in 2035, up from 2.7 mb/d in 2012. By contrast, production in *Ecuador*, the only other Latin American OPEC member, is projected to fall from about 500 kb/d today to less than 300 kb/d by 2035, as its declining reserves are depleted, though development of the heavy Ishpingo-Tambococha-Tiputini oilfields in the environmentally sensitive Yasuni National Park could arrest or even reverse this decline if it were to proceed (as suggested by statements made by Ecuador's President in August 2013).

Supply trends and potential implications for prices

Our projections in the New Policies Scenario highlight how the anticipated growth in reliance on oil production in the Middle East has been postponed, as a result of steady upstream technological innovation that is bringing new resources elsewhere into the realm of commercial viability. The growth in LTO and the expansion of deepwater production are examples of this trend and these two phenomena play a large role in determining the dynamics of oil supply in the early part of the projection period, during which non-OPEC supply is sufficient to meet the lion's share of the growth in demand. This implies that OPEC producers will need to limit their output in order to balance the market (allowing, also, for a continued increase in production in Iraq).

Over the longer term, however, the situation is reversed as non-OPEC production first stabilises and then begins to decline in the latter part of the 2020s. Increases in demand are then met by growth in OPEC production (Figure 14.14). Over the whole period to 2035, OPEC countries provide over two-thirds of the overall increase in supply, OPEC increasing its share of global production from 43% to 46%. This share is considerably less than OPEC's share of the world's remaining recoverable resources of oil. It is also lower than that projected in recent *WEO*s, when it has been closer to 50% by 2035.

Figure 14.14 ▷ Oil production changes by OPEC/non-OPEC grouping in the New Policies Scenario



Note: Share of OPEC is for the end of the interval shown, *i.e.* for 2012 in the first column, for 2015 in the second, and so on.

These longer-term market dynamics are accompanied by some shorter-term signals that might be understood to indicate a more comfortable supply-demand balance ahead. Global demand growth has slowed, compared with the years between 2000 and 2008, in large part as a result of the protracted economic crisis in Europe, efficiency gains in the United States and some signs of a slowing rate of growth in the Chinese economy. Alongside uncertainties over the future pace of economic growth and of oil demand, there is also an expectation in some quarters that supply prospects are sufficiently bright to outpace demand growth in the years ahead. Focusing on the rapid growth of light tight oil production in the United States, this view posits the start of a new era of ample supply, raising the possibility that the market could in practice be brought into equilibrium with a lower oil price than the one we project in the New Policies Scenario (where the price rises slowly to reach $128/barrel [in year-2012 dollars] in 2035[16]). The Brent and WTI futures curves indeed point to an easing in the oil price over the next few years (although history shows that futures prices are not reliable predictors of future prices).

We examine the possibility of a sustained period of lower prices below. But there are also reasons to support a more cautious assessment of the supply outlook. Although the resource base is more than sufficient to justify an optimistic outlook for oil production, low-risk and low-cost opportunities for investment are limited and it remains a huge

14

16. The trajectory in the New Policies Scenario tends to be relatively flat over the first half of the projection period and increases at a slightly faster pace after 2020, reflecting the overall dynamics of markets. However, our price paths follow smooth trends as we do not attempt to anticipate the timing or extent of fluctuations in the oil price over the projection period (while recognising that, in reality, the oil price may from time to time deviate substantially from the assumed path in response to economic, energy market or geopolitical perturbations). We examine in this section a Low Oil-Price Case: some commentators also argue that we may be heading for a substantially higher price than in the New Policies Scenario (IMF, 2012).

undertaking to mobilise new investment at the pace required to keep up with the impact of declining output from existing fields. On LTO, we are not as bullish as some about the North American prospects: after rapid increases over the next five years, we project a period of slower growth, eventually leading to a plateau in the latter part of the 2020s and a slow decline thereafter, due to depletion of currently estimated recoverable resources. Moreover, LTO growth outside North America is projected to be too slow for LTO to take over as the engine of production growth in the latter part of the projection period.

We also see downside risks in a number of other key producing countries. The political and logistical challenges to growth of output in Iraq remain formidable; in fact, the projections for Iraq are revised downwards compared with last year, as a result of slow progress on the ground. The technological and investment challenges in the Brazil pre-salt fields are also formidable; even at the levels of our more conservative view on production prospects, compared with those held by Petrobras and the Brazilian government, there remains the possibility of slippage in project implementation (see Chapter 11). Similarly, the recent track record in moving projects forward in Kazakhstan invites a prudent view of the speed of new developments there. Iraq, Brazil and Kazakhstan together account for more than 10 mb/d of the production growth anticipated in the New Policies Scenario to 2035 (total projected growth in oil production is 11 mb/d).

The prospects in some other OPEC countries, besides Iraq, also raise questions. Libyan production has again plummeted amid labour disputes, civil unrest and political discord. Nigeria is struggling to resolve its internal conflicts and production is decreasing. Though there are hopeful signs, a quick resolution of the tensions between Iran and the international community still seems some way off. Venezuela is going through a political transition that has so far failed to provide certainty for future upstream investment. Kuwait is no further along than it was ten years ago in the political process required to put its ambitious capacity increase targets on track. Even in Saudi Arabia, United Arab Emirates and Qatar, there are some hints that the US shale revolution could induce a slowdown in investment. Our estimate of global spare capacity rises from 5 mb/d currently to more than 7 mb/d after 2015, but this would already start diminishing again by 2018.[17] As emphasised in successive *Outlooks*, shortage of investment remains a significant threat to future supply and this consideration informs the judgments underlying the New Policies Scenario.

A Low Oil-Price Case

A Low Oil-Price Case is based on the premise that supply developments in a number of countries turn out more positively than we project in the New Policies Scenario.[18] There are a number of countries that could deliver production above expectations. In the United States, the astounding vitality of the industry could deliver LTO output of up to 6 mb/d

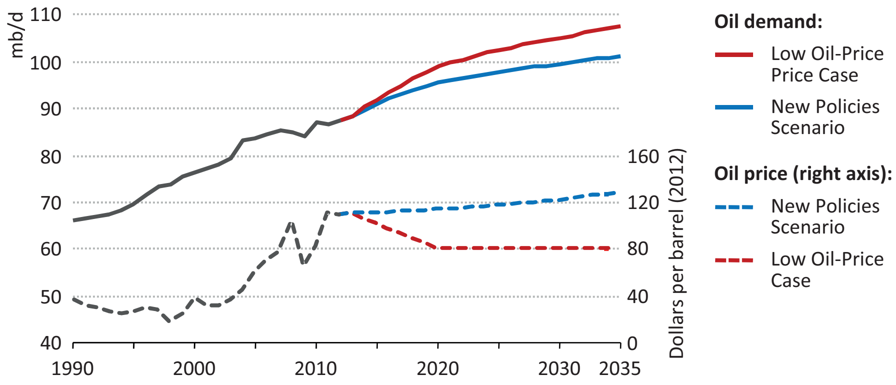
17. This is based on the production capacity projections from the *Medium-Term Oil Market Report 2013* (IEA, 2013) versus the oil demand projections of the New Policies Scenario.

18. An alternative low oil-price case could emerge in the event of persistent weakness in the global economy, bringing down the anticipated growth in oil consumption: see Chapter 1, Box 1.2.

(as some industry sources predict), about 2 mb/d above the projections. In Canada, if the controversies over the Keystone XL pipeline and the pipelines from Alberta to the British Columbia coast were to be resolved quickly, oil sands production could easily grow 1 mb/d higher than we project.[19] Also in North America, Mexico's reform of the laws limiting the participation of foreign companies in the hydrocarbon sector is high on the agenda of the new administration and such reforms have the potential to generate much more rapid development of its large resources.

Moving outside North America, successful implementation of Petrobras' plans in Brazil could provide another 1 mb/d or more in output on top of our projections in 2020 (as in the High Brazil Case that we examine in Chapter 11). Venezuela is suffering from a severe lack of capital and technical expertise to develop its massive hydrocarbon resources: re-opening the country's oil sector could easily deliver an additional 2 mb/d by 2035. Iraq's stated ambition to reach 9 mb/d of output by 2020 is about 1 mb/d above the 2035 projections. If Iran were to resolve its conflict with the international community and embark on an ambitious programme of attracting upstream investment, its resources, which are similar in extent to those of Iraq, would support production at a level some 4 mb/d higher than the projections. Nigeria, Syria, Libya, North and South Sudan, and, even, Russia (if it makes progress on the evolution of its hydrocarbon tax system) all have potential for higher output. Taking all these possibilities together, there is potential for a level of production capacity close to 13 mb/d higher than the production level projected in the New Policies Scenario. Of course, not everything can be expected to go well in all of these countries: but, even an extra 5-6 mb/d of capacity would have a marked impact on the oil market.

Figure 14.15 ▷ Oil price and oil demand trajectories in the Low Oil-Price Case compared with the New Policies Scenario



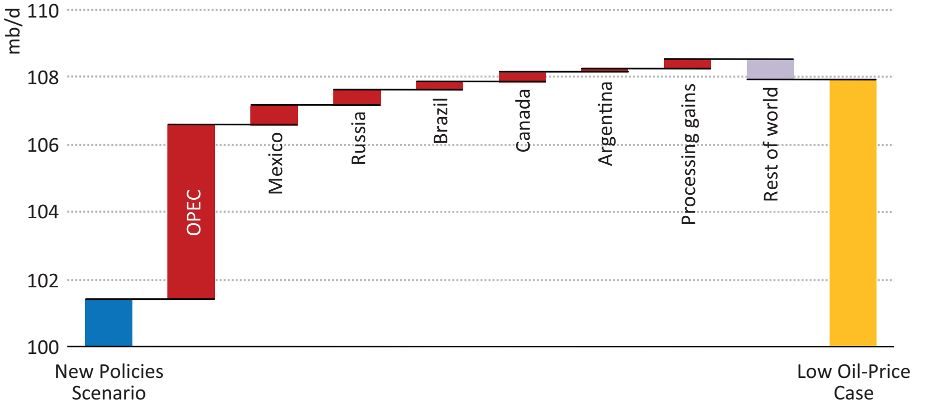
We model this possibility as a Low Oil-Price Case, in which supply growth is sufficiently rapid to ease the market balance, bringing on and supplying additional consumption

19. This would track more closely the projections of the Canadian Association of Petroleum Producers and of ERCB, the regulator in Alberta.

of oil.[20] As suggested by the supply cost curves discussed in Chapter 13, prices could reasonably be expected to stabilise in this case at around $80/barrel, around the level of the cost of the marginal barrel required to meet the additional demand, which reaches 107.9 mb/d in 2035 in this case (Figure 14.15). Note that the assumptions on policies (on efficiency, biofuels, etc.) remain those of the New Policies Scenario, which explains why demand is still lower than in the Current Policies Scenario.

To examine the consequences of such a Low Oil-Price Case, one needs to specify which countries are actually able to produce more. The United States, Canada, Brazil and Russia, even if one takes a more optimistic view of their supply potential, would be penalised by lower oil prices (as the costs of incremental production are relatively high), so their output remains at levels similar to those in the New Policies Scenario. In the projections, it is rather Mexico, Venezuela, Iran and, to a lesser extent, Nigeria, Libya and Kuwait that provide the bulk of the required increase in production. Indeed Figure 14.16 shows that the bulk of the increased demand is met by OPEC countries, with Mexico the leading contributor among non-OPEC countries, followed by Russia, and smaller contributions coming from Brazil, Canada and Argentina. Other countries see a decrease in production, due to lower prices.[21]

Figure 14.16 ▷ Contributions to meeting the additional demand in the Low Oil-Price Case relative to the New Policies Scenario, 2035



Such a scenario would be a mixed blessing for OPEC countries – a finding that calls into question its likelihood in practice. Despite higher production, lower prices mean that OPEC total revenues in 2035 decline from $1.6 trillion in the New Policies Scenario to $1.1 trillion

20. In Chapter 13, we have argued that production is limited not by price but by the capabilities of the industry to develop resources fast enough. In the context of the Low Oil-Price Case, though this continues to be a limitation, it is partly alleviated by easier access to lower cost resources, which also are less dependent on skilled personnel.

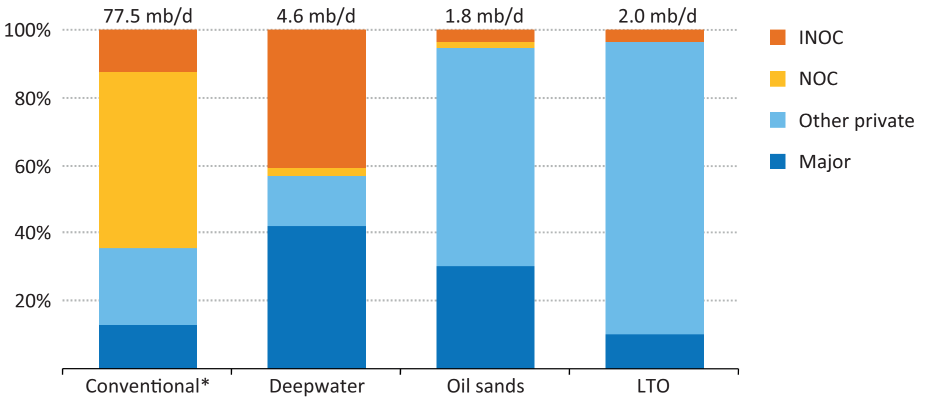
21. Because the Low Oil-Price Case is not a fully-fledged scenario, *i.e.* it only changes parameters for the oil sector rather than for all fuels, it uses the same gas and coal prices as the New Policies Scenario. This results, in particular, in a large drop in coal-to-liquids and gas-to-liquids production, as the ratio of oil to coal and gas prices is less favourable than in the New Policies Scenario.

in the Low Oil-Price Case. The Low Oil-Price Case would also bring international prices below the estimated fiscal breakeven prices in many large resource-owning countries, *i.e.* the price needed to generate sufficient revenue to balance government budgets (based on current spending commitments). Estimates for these fiscal breakeven prices vary, but one recent study put the OPEC output-weighted average in 2013 at $105/barrel, an increase of $6/barrel since 2012 (APICORP, 2013). These breakeven price estimates for 2013 vary by country from $58/barrel in Qatar to (an exceptionally high) $144/barrel in Iran, meaning that the fiscal risks associated with a fall in price would not be evenly distributed. Nonetheless, for many significant producers, this could be an important source of resistance to the production levels and price trajectory outlined in the Low Oil-Price Case.

Upstream industry structure

In Chapter 13, we presented the estimate that national oil companies (NOCs) or their host governments control almost 80% of the world's proven-plus-probable reserves, compared with around 20% for privately-owned companies.[22] There are also differences in the types of resources in which NOCs (whether nationally focused or internationally-oriented) are involved in developing. NOCs and international NOCs (INOCs) tend to dominate conventional oil production, accounting for two-thirds of total output in 2012 (excluding deepwater production). Private companies are pushed towards a stronger presence among resources that are more technically challenging to exploit (but more accessible), such as deepwater projects (57% of production in 2012), oil sands (95%) and the rapidly expanding area of LTO (96%) (Figure 14.17). Growth in LTO output is strongly associated with the ability of smaller entrepreneurial companies to react quickly, deploy technical innovations and control costs.

Figure 14.17 ▷ Oil production by selected resource and company type, 2012



* Excluding oil produced in deepwater.

Source: IEA analysis based on AS Rystad Energy.

22. See Chapter 13, Box 13.3 for an explanation of the company categories used in this analysis

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Box 14.4 ▹ The rising overseas presence of Asian national oil companies

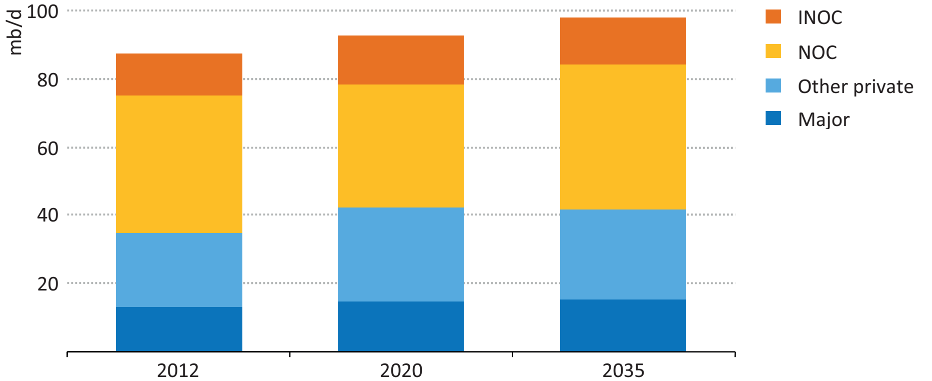
As the centre of gravity of global oil demand (and imports) shifts ever more towards the Asia-Pacific region, so Asian NOCs have become increasingly prominent buyers of upstream assets outside their home markets. In 2012, for the first time, national oil companies took the largest share of global spending on mergers and acquisitions. Chinese and Southeast Asian companies, notably CNPC, CNOOC and Sinopec from China, Malaysia's Petronas, Indonesia's Pertamina and Thailand's PTT, took the lead. Their acquisitions (including both oil and gas) accounted for over one-fifth of the world total. This increase in overseas holdings is motivated by various factors: the desire to hold more diversified portfolios of assets, to access new resources and to develop integrated supply chains (the latter in particular for natural gas) or, simply, to gain technical know-how and expertise (for example, for deepwater or unconventional resources). As a result, Asian NOCs are becoming increasingly important producers outside their borders. In the case of China, we estimate that, as of mid-2013, the overseas oil production entitlement of China's companies has grown to around 2 mb/d. There is scope for this figure to increase further and we expect that it will rise to between 3-3.5 mb/d by 2015, based on production growth from existing assets as well as new acquisitions.

It is sometimes assumed that this overseas production is earmarked directly for the domestic Chinese market, but there is no evidence that this is the case. Even if it were, the volumes of China's overseas oil, while impressive, would fall far short of the projected requirement for oil imports, which reaches 6.7 mb/d by 2015 and continues to rise strongly to 12.2 mb/d by 2035. The gap between overseas production and the import requirement is even likely to widen in the longer term, as the accumulation of overseas assets runs up against limits in the opportunities for productive international investment (due, in large part, to the grip of other NOCs over their domestic resources).

Over the projection period, we anticipate a gradual move towards a more interconnected upstream landscape. Markets in North America are increasingly a focus for international mergers and acquisitions; of the total spending on upstream acquisitions in 2012, more than half was in the United States and Canada, although Africa has also seen a rise in activity. The acquisition interest in North America has been driven in large part by unconventional oil and gas. NOCs are increasingly involved in North America, seeking a foothold in an important market as well as access to technology and expertise. Asian NOCs have been particularly active, with Canada alone seeing two major deals go through in 2012: CNOOC's $15 billion acquisition of Nexen and Petronas' $5 billion purchase of Progress (Box 14.4).

Despite the rise in NOC holdings outside their home markets, in the medium term, at least until the mid-2020s, international majors and other private companies do have opportunities to increase their share of global production. As long as the oil price remains relatively high, these companies can develop resources at the higher end of the international cost curve, which play to their strengths and technical expertise. Resources in this category are more generally accessible. International majors and other private companies are also able to apply knowledge gained from North America in other countries that have unconventional resource potential. The estimates for oil production by company type suggest that majors and other private companies are set to increase their share of global production from 40% today to 45% in 2020 (Figure 14.18). Over this period, which broadly coincides with the anticipated rise and plateau of non-OPEC production, they would account for all of the anticipated growth in global production.

Figure 14.18 ▷ Oil production by company type in the New Policies Scenario



Note: The projections assume no change in the ownership of reserves.

Source: IEA analysis based on Rystad Energy SA.

In the longer term, as growth in output from unconventional oil slows and production from private companies' conventional assets declines, the trends are reversed. NOC access to the world's largest, lowest-cost conventional oil resources underpins an expansion in their share of global production, from 39% to 43% (excluding INOCs) between 2020 and 2035 in the New Policies Scenario. This process would be accompanied in some countries by opportunities for new partnerships between NOCs and international companies, to marry the resources of the former with the expertise and investment capital of the latter.

Investment

We estimate that the total investment required in upstream oil activities for the period from 2013 to 2035 is around $9.4 trillion (in year-2012 dollars) in the New Policies Scenario (Table 14.7). If upstream investment in natural gas is included, the cumulative total rises to more than $15 trillion. This means an annual average upstream spend, for oil and gas, of $660 billion per year, to provide the capacity needed to meet growing demand and to offset decline at existing fields, allowing for the higher capital cost of exploiting more technically-challenging sources of supply, such as deepwater and unconventional projects in non-OPEC countries. The overall total allows, also, for increased unit upstream costs for exploration and development, partly offset by technology learning.

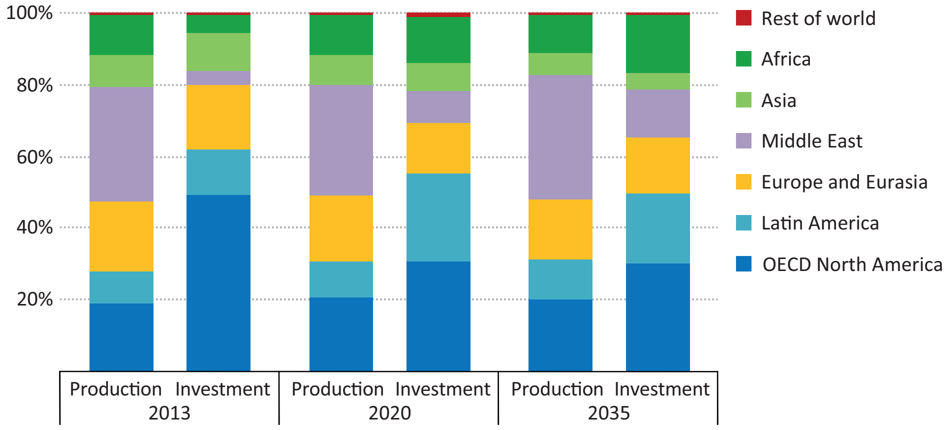
Table 14.7 ▷ Cumulative investment in upstream oil and gas supply by region in the New Policies Scenario, 2013-2035 ($2012 billion)

	Cumulative total		Annual average
	Oil	Gas	
OECD	**3 354**	**2 383**	**249**
Americas	2 826	1 645	194
United States	2 060	1276	145
Europe	450	562	44
Asia Oceania	77	176	11
Non-OECD	**6 041**	**3 331**	**407**
E. Europe/Eurasia	1 180	937	92
Russia	739	610	59
Asia	664	972	71
China	422	347	33
India	59	117	8
Middle East	872	245	49
Africa	1 507	711	96
Latin America	1 818	466	99
Brazil	1 270	118	60
World	**9 394**	**5 714**	**657**

Looking at the upstream investment requirement on a regional basis, the amounts required are not at all proportional to the volumes of oil that the respective regions are anticipated to produce (Figure 14.19), because of large regional differences in unit development costs and decline rates. In the Middle East, the capital intensity of production and the decline rates for production at existing fields are the lowest in the world; as a result, the share of this region in global upstream investment is considerably lower than its share in production. The Middle East's share in total production rises by three percentage points to 2035 (reflecting the increasing reliance on large Middle East resource-holders in meeting global demand in the latter part of the projection period), but it is noteworthy that their share in total investment grows by ten percentage points. This reflects a gradual rise in the region's unit production costs, as the easiest resources are depleted and operators move on to tackle more difficult and expansive accumulations.

North America, by contrast, the current location for half of the world's upstream investment in oil, is responsible for only one-fifth of output, reflecting the fact that the resources being developed in this region, notably the Canadian oil sands and LTO in the United States, are relatively expensive to produce. The share of investment in North America stabilises at around 30% of the global total in the projections, but remains high relative to the region's level of production. South America's global share of capital expenditures rises sharply in the period to 2020, as production in Brazil ramps up.

Figure 14.19 ▷ Global share of oil production and investment by region in the New Policies Scenario



The required level of investment is within the capacity of the industry to deliver. Based on analysis of the spending plans of seventy leading upstream companies, we estimate that total upstream oil and gas spending in 2013 will be around $710 billion, a year-on-year increase of 6% and a record high for a fourth consecutive year (Table 14.8).[23] This is above the average level required between 2013 and 2035 in the New Policies Scenario. In the projections, the required level of annual upstream spending is close to $700 billion in the first part of the projection period, but dips slightly in the latter part, when lower cost OPEC Middle East countries start to deliver most of the production increases.

Annual global upstream oil and gas investment increased in real terms almost three times between 2000 and 2013 (Figure 14.20). The trend of rising spending has been supported by the high oil prices which have prevailed since 2008, which increase the potential return on investment, and the rising cost of projects, of which a growing share has been unconventional. Part of the increase also reflects higher unit costs for exploration and development, taking into account the prices for cement, steel and other construction materials and equipment, as well as the cost of hiring skilled personnel and contracting drilling rigs and oilfield services.

As outlined in the analysis of supply cost in Chapter 13, the World Energy Model anticipates a further evolution in costs over the projection period. On the one hand, there are new and improved technologies that tend to reduce capital and operating costs over time. On the other, there are increases associated with the need to develop more difficult and expensive (and generally smaller) reservoirs, as oil resources in various countries and regions are depleted. There are also cost pressures that are related to the oil price, following the logic that high prices tend to push up supply and service costs, as companies in that sector try to capture a larger share of the rent. The net result in the New Policies Scenario is an increase

23. These investment trends are based on the announced plans of 70 oil and gas companies. Total upstream investment is calculated by adjusting upwards their spending according to their share of world oil and gas production for each year.

Table 14.8 ▷ Oil and gas industry investment by company (nominal dollars)

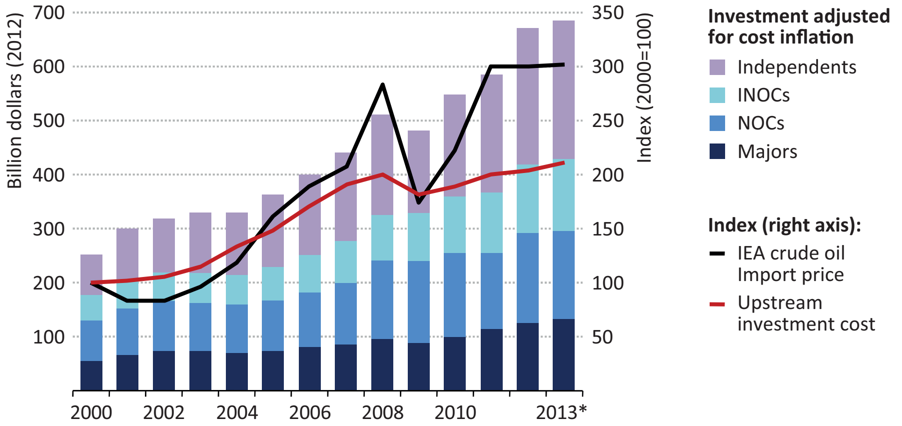
	Upstream			Total		
	2012 ($ billion)	2013 ($ billion)	Change 2012/2013	2012 ($ billion)	2013 ($ billion)	Change 2012/2013
Petrochina	36.2	38.5	6%	56.6	57.0	1%
Petrobras	24.5	30.5	24%	42.9	47.3	10%
ExxonMobil	36.1	37.2	3%	39.8	41.0	3%
Gazprom	38.5	35.6	-7%	43.2	40.0	-7%
Chevron	27.5	33.0	20%	30.9	36.7	19%
Royal Dutch Shell	25.3	28.0	11%	29.8	33.0	11%
Sinopec	12.7	13.7	8%	27.1	29.2	8%
Total	19.0	22.4	18%	23.8	28.0	18%
Pemex	19.7	20.0	1%	23.6	25.3	7%
BP	18.3	19.5	7%	23.1	25.0	8%
Rosneft	8.6	11.5	34%	14.9	20.0	34%
Statoil	16.4	17.3	6%	18.0	19.0	6%
Eni	13.5	13.3	-1%	17.7	17.5	-1%
ConocoPhillips	14.2	14.3	1%	15.7	15.8	1%
Lukoil	8.9	12.0	35%	11.6	15.7	35%
CNOOC	8.5	12.9	51%	8.6	13.0	51%
BG Group	11.0	11.7	6%	11.3	12.0	6%
Apache	9.0	9.9	10%	9.5	10.5	10%
Occidental	8.2	7.7	-6%	10.2	9.6	-6%
Chesapeake	12.2	6.4	-48%	14.6	7.6	-48%
Anadarko	5.8	6.7	14%	7.3	7.4	1%
Suncor Energy Inc.	5.6	5.9	6%	6.3	7.2	13%
Devon Energy Corp	7.3	5.5	-24%	8.2	6.7	-19%
Repsol YPF	3.3	3.4	5%	4.3	4.5	5%
EnCana	3.3	3.0	-9%	3.5	3.1	-11%
Sub-total 25	393.8	420.0	7%	502.7	532.0	6%
Total 70 companies	541.3	572.8	6%	n.a	n.a.	n.a.
World	**669.6**	**708.6**	**6%**	**n.a.**	**n.a.**	**n.a.**

Notes: Only publicly available data have been included (IEA databases include both public and non-public estimates for all major oil and gas producing companies). The world total for upstream investment is derived by prorating upwards the spending of the 70 leading companies, according to their estimated share of oil and gas production in each year. Pipeline investment by Gazprom is classified as upstream, as it is required for the viability of projects. The "Total" column includes both upstream and downstream, as well as other investments (such as petrochemicals, power generation and distribution) for a few companies for which a breakdown is not publicly available. The 2013 figures are based on mid-year budgeted spending plans. The figure for Rosneft includes TNK-BP's 2013 spending plan; the one for CNOOC excludes Nexen's proposed spending.

Sources: Company reports and announcements; IEA analysis.

in real costs over the projection period. This tendency towards increased costs might be expected to lead to a rising figure for annual investment over the projection period. In practice, though, it is more than counter-balanced over the projection period as a whole by the growing share of production anticipated to come from the Middle East, where both direct costs and the cost of capital – either NOC cash flow or government funds – are the lowest. This explains why the projected annual investment requirement (which averages $660 billion) shows a slight decline in the latter part of the projection period.

Figure 14.20 ▷ Worldwide upstream oil and gas investment and the IEA Upstream Investment Cost Index



* Budgeted spending. Notes: The IEA Upstream Investment Cost Index, set at 100 in 2000, measures the change in underlying capital costs for exploration and production. It uses weighted averages to remove the effects of spending on different types and locations of upstream projects.

Sources: IEA databases and analysis based on industry sources.

Although industry has already demonstrated the ability to invest at the required level, its capacity to do so over a period of decades is subject to a number of potential barriers. As described earlier, there is something of a two-paced approach to investment over the coming decades. In the initial period, which lasts until the early 2020s, the incremental barrel brought to market tends to come from investments made by private companies – broadly in line with the gradual expansion of non-OPEC supply. This puts the accent over this period on ensuring appropriate conditions and incentives that allow this investment to take place in a timely way, whether related to fiscal terms, licensing arrangements or other regulatory arrangements, such as local content requirements.

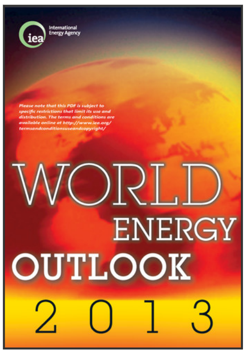
These elements continue to be important in the longer term but, as reliance for satisfying the additional barrel of demand switches over in the 2020s more towards national oil companies, notably those of OPEC countries, some additional considerations come more firmly into play. These include the depletion policies of major resource-owning countries, rising government call on oil revenue in some major producing countries and the related possibility that oil revenues could be so apportioned as to leave the upstream short of capital for investment. Among the other factors that could affect investment flows, political instability and other political considerations provide an unpredictable, but ever-present, backdrop to the decisions to be made about commitments of upstream capital. The conflict in Syria and the economic sanctions imposed by the United States and the European Union on Iran provide two current examples. More broadly, though, an increasingly potent constraint faced by the industry as a whole (and which remains, at least partly, within its power to address) is the availability of sufficient skilled employees (Box 14.5). The looming shortage of key personnel stems from a downturn in the hiring cycle from the 1980s until the mid-1990s – a consequence, in part, of low oil prices over this period – that essentially skipped a generation of employees. Had those human resources joined and remained in the industry, they would now have the experience needed to replace an older generation approaching retirement. The industry has to confront and manage this gap in available expertise if it is to keep operating at the demanding pace indicated here.

Box 14.5 ▹ Staffing the oil and gas business

Sufficient availability of skilled personnel – geologists, geophysicists, reservoir engineers, drilling and completion engineers, and production engineers, among others – is a vital condition that has to be met for the projections in the *Outlook* to be realised. This cannot be taken for granted. The oil and gas industry currently has a high level of vacancies in key disciplines and is confronted with an expertise gap, resulting from uneven past hiring cycles and a high rate of attrition among its oldest and most experienced employees (SBC, 2012).

According to a recent survey of companies operating in the North Sea, over 70% reported difficulties in recruiting qualified candidates (OGP, 2013). On a regional basis, the largest deficits in skilled personnel are in North America, Africa and the Middle East, with the situation perhaps most pressing in sub-Saharan Africa, where around three-quarters of the targets for recruitment from universities in the region are presently unmet. In the United States, the pool of talent from universities is sufficiently deep, but over 60% of post-bachelor graduates are non-US citizens and often leave the country after graduation (SBC, 2012). While companies have stepped up their recruiting efforts in the last few years, it takes time (ten to fifteen years on average) for new recruits to gain sufficient experience to take on leadership positions. Concerns over climate change and environmental issues exacerbate the recruitment challenges faced by the industry in some countries, emphasising the self-interested need for oil companies to demonstrate clearly their social and environmental credentials.

The result of staffing difficulties can be felt in higher costs or in project delays – or, potentially, in the quality of project implementation. All of these could have an impact on our projections and the latter could have potentially very serious consequences for an industry under increasingly strict scrutiny for its environmental performance. Against this background - and until the new recruits come through into more senior positions –companies have to be imaginative: they can outsource, seek to standardise projects in a way that reduces learning times, or invest in new technologies that relieve pressure on existing personnel.



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