# OIL

# Medium-Term Market Report 2015

## Market Analysis and Forecasts to 2020



International Energy Agency

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# OIL Medium-Term Market Report 2015

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# FOREWORD

The oil market outlook has dramatically changed since the 2014 edition of this *Medium-Term Oil Market Report* was released eight months ago. Since then, oil prices have plummeted by over 50%. OPEC has torn up the book on supply management. Companies have taken an axe to budgets. Exporting countries are struggling with financial gaps. Upstream investments have been scaled back.

The IEA *Oil Market Report* has done a vital job of tracking, and even anticipating, these developments on a monthly basis and assessing their short-term impacts, adding much needed visibility to a fast-changing market whose transformation is testing the preconceived notions and accepted wisdom of industry participants and policymakers alike. But while price declines of a magnitude such as was just experienced call for urgent responses, their consequences for the medium term – the next five to six years – warrant at least as much attention, for today's investment decisions will take years to translate into physical supply/demand reality. Or so at least we thought, until North American light tight oil (LTO), with its short lead and payback times, came to occupy such a large share of the supply mix.

Understanding the medium-term consequences of the oil market selloff against the backdrop of changing underlying conditions is what this *Report,* an annual companion to the *OMR,* sets out to do. As it rightly notes, the trick is not just to take stock of how price and supply expectations have been reset and project economics revisited – that goes without saying. Nor is it to determine whether a market rebalancing and price rebound will occur, for that seems inevitable. Rather, the challenge is to understand how recent twists in supply and demand conditions – such as the advent of LTO on the supply side and, on the demand front, shifts in the global economy and the energy mix – will shape the pace of that recovery and cause it to substantially differ from those that followed earlier price drops of a similar magnitude in the 1980s, the 1990s and in the last decade.

In the oil market, the past is not prelude. Experience is an imperfect guide, and assumptions derived from it are ceaselessly "mugged by reality" and must be questioned and revisited. Staying ahead of the curve – inasmuch as possible when so many moving parts and external drivers will ultimately shape market outcomes – calls for foresight, analytical depth, alertness to new factors. It also requires paying attention not only to changes at the wellhead or the gasoline pump, but at every intermediary step of the supply chain, including refining, transportation and storage. As this *Report* shows, a key point of departure in today's price correction from previous ones might be the price elasticity of LTO, an unconventional supply source that is not only more scalable than conventional oil when price conditions warrant it – but might also be quicker to ramp down when they don't.

It is all the more critical to understand how the rules of the markets have changed given uncertainty surrounding the future of negotiations between Iran and the P5+1, tensions between Russia and the west over Ukraine, and myriad other factors. This *Report* endeavours to do just that, looking in detail at the outlook for demand, OPEC and non-OPEC supply, refining, crude trade and product supply until the end of this decade. That makes it required reading for anyone interested in the oil market.

This *Report* is published under my authority as Executive Director of the International Energy Agency.

Maria van der Hoeven
Executive Director
International Energy Agency

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For contact information, please see https://www.iea.org/oilmarketreport/omrcontacts/.

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# EXECUTIVE SUMMARY

As surprising as it might have seemed, the price collapse that has shaken the oil market since June 2014 was neither wholly unexpected nor unprecedented. Not unexpected, because earlier editions of this *Report* had pointed at a looming surge in implied OPEC spare capacity, an expression of the supply/demand imbalance that would emerge if the producer group, faced with rising North American supply, held production above the "Call on OPEC and stock change". Not unprecedented, because more or less equally sharp corrections have rocked the market roughly every 10 years since the price shocks of the 1970s: in 1986, in 1998, and again in 2008. Looking at the medium-term consequences of this latest price plunge, the real question is not so much how price and supply growth expectations have been reset; nor whether a rebalancing of the market will occur – for that is inevitable. The issue is how that necessary rebalancing, and the price recovery that will accompany it, might depart from those that followed similar price drops in the past, and where they will leave the market after they run their course.

**Table ES.1** Global balances

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| **GDP Growth Assumption (% per year)** | **3.31** | **3.45** | **3.67** | **3.68** | **3.71** | **3.75** | **3.77** |
| **Global Demand** | **92.43** | **93.34** | **94.47** | **95.68** | **96.86** | **98.00** | **99.05** |
| Non-OPEC Supply | 56.59 | 57.32 | 57.78 | 58.26 | 58.96 | 59.52 | 60.00 |
| OPEC NGLs, etc. | 6.39 | 6.58 | 6.82 | 6.88 | 6.89 | 6.91 | 6.93 |
| **Global Supply excluding OPEC Crude** | **62.98** | **63.91** | **64.60** | **65.14** | **65.85** | **66.43** | **66.93** |
| **OPEC Crude Capacity** | **35.03** | **34.73** | **35.12** | **35.41** | **35.65** | **35.91** | **36.24** |
| **Call on OPEC Crude + Stock Ch.** | **29.44** | **29.43** | **29.87** | **30.54** | **31.02** | **31.58** | **32.12** |
| Implied OPEC Spare Capacity* | 5.58 | 5.30 | 5.25 | 4.87 | 4.63 | 4.33 | 4.13 |

* Spare capacity is defined as the difference between estimated OPEC capacity and the 'Call on OPEC + Stock chg'. Actual idle capacity is lower than spare capacity when OPEC produces above the Call.

Unlike earlier price drops, this one is both supply- and demand-driven, with record non-OPEC supply growth in 2014 providing only one of the factors behind it, unexpectedly weak demand growth another. On the supply side, US light, tight oil (LTO) extraction technologies, which at the time of the previous market correction barely registered as a source of production, have unlocked a vast resource that long seemed off-limits, and have profoundly upended the traditional division of labour between OPEC and non-OPEC. The latest price drop is also occurring at a time when the dynamics of global demand and the place of oil in the fuel mix are undergoing dramatic change. Emerging economies – China chief among them – which 10 years ago seemed an unstoppable engine of near-vertical demand growth, have entered a new, less oil-intensive stage of development. The global economy, reshaped by the information technology revolution, has generally become less fuel intensive. Concerns over climate change are recasting energy policies. And the globalisation of the natural gas market, coupled with steep reductions in the cost and availability of renewable energy, are causing oil to face a level of inter-fuel competition that would have seemed unfathomable a few years ago.

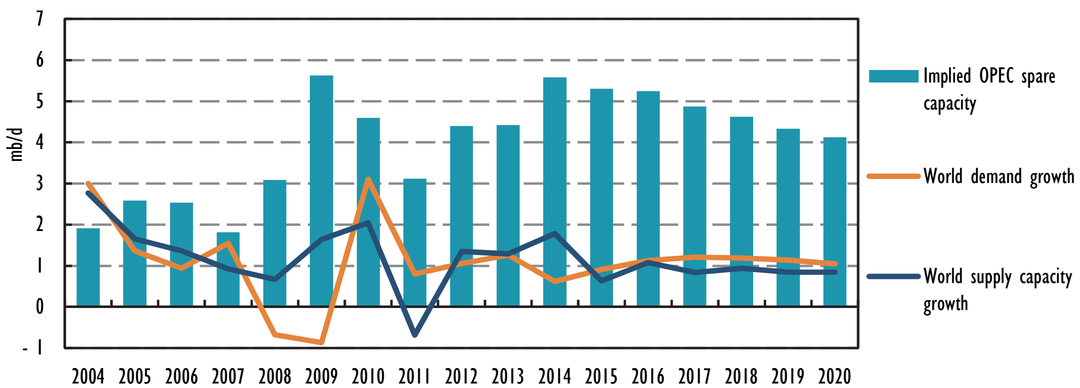
Changed underlying market conditions will naturally call for a different form of readjustment to the price drop than during previous market cycles. The usual market logic dictates that the deeper and faster a price decline, the stronger the recovery; conversely, the faster a rally, the more severe the inevitable correction. Recent market trends certainly fit the latter pattern: after years of sustained, record-high prices, a day of reckoning has arrived. But based on the analysis of this *Report*, the rebound will be different, because non-OPEC supply has become far more price elastic than in the past, while demand has at the same time become significantly more price inelastic on the downside.

The result is that, barring any unexpected supply disruption or major, energy-related change in policy, the market rebalancing will likely occur relatively swiftly but will be comparatively limited in scope, with prices stabilising at levels higher than recent lows but substantially below the highs of the last three years. On current projections, the dramatic inventory build of the last few months grinds to a halt as early as mid-2015, and the market starts tightening appreciably, with a steady and gradual increase in the nominal Call on OPEC, from 2016 onwards. One of the consequences of the North American supply revolution is that the presumed high price-elasticity of North American LTO, which itself constitutes the single largest source by far of global incremental supply, will limit the usual overshooting and undershooting of market corrections both on the upside and the downside.

Another major takeaway from this *Report* is that the price decline, notwithstanding the sheer scope of the supply response it has already dictated, will not succeed in derailing the underlying forces in motion in the market or alter its expected course of development. If anything, pre-existing patterns will emerge reinforced from the adjustment. On the supply side, the top two sources of capacity growth identified in past editions of this *Report* – North America and Iraq – loom even larger by the end of the decade than previously expected. The price correction will cause the North American supply "party" to mark a pause; it will not bring it to an end. By the beginning of the next decade, the region's non-conventional production will account for an even larger share of the supply mix than earlier forecast. While estimates of its production have been adjusted downwards, the region nevertheless still leads global supply growth by a wide margin by 2020, with forecast gains of 3.0 mb/d. Other sources of non-OPEC supply will be far more adversely affected by the price reset -- none more so than Russia, now projected to swing into contraction of more than 0.5 mb/d by 2020, down from an earlier projection of small growth.

And the formidable hurdles facing Iraq, including the twin challenges of an oil-price plunge and a vicious Islamic State in Iraq and Levant (ISIL) insurgency, have not succeeded so far in slowing its production growth, which by December 2014, defying expectations, had surged to a monthly average of 3.7 mb/d, a 35-year high. While the risks to the forecast are considerable, Iraq is seen as emerging from the price correction head and shoulders over its OPEC counterparts, with a larger production footprint than previously estimated, accounting for an even larger majority of OPEC incremental capacity than previously forecast (assuming international sanctions on Iran remain in place). Meanwhile, on the demand side, a projected slowdown in growth compared to the historic trends prevalent before the Great Recession is expected to remain on track despite lower prices.

**Figure ES.1** Global oil balances, 2004-20



More than ever, caveats apply to this forecast. Political risk to supply will remain extraordinarily elevated in the next few years, both on the upside and the downside, after years of chronic disruptions in the oil-rich Middle East and North Africa region. Lower oil prices may indeed heighten the risk of political disturbances in countries where social spending requires high oil export and fiscal revenues and buffers are insufficient to make up for the shortfall, while territorial gains and activism by increasingly aggressive terrorist groups also pose a threat to supply, not least in Iraq. But lower prices can also offer upside risk to supply. For producer countries, lower export and fiscal revenues provide an incentive to maximise output and stimulate production growth, in a bid to make up in volume for per-barrel losses. Down cycles typically lead producer countries to tone down resource-nationalistic policies and thus can in some ways at least ease above-ground hurdles to supply. Iran also may be in a position to increase production and exports rapidly if it reached agreement over its nuclear program with the so-called P5+1, a possibility that is not this Report’s assumption. Nevertheless, for the next few years, the global oil market looks set to begin a new chapter of its history, with markedly changing demand dynamics, sweeping shifts in crude trade and product supply, and dramatically different roles for OPEC and non OPEC producers in regulating upstream supply. That chapter will undoubtedly not be the final one, and the oil market and industry will keep reinventing themselves. But it will be profoundly different from anything that had been known so far.

## Prices

After years of relatively stable, record-high prices, the oil market collapsed by roughly 60% from its June 2014 high above USD 115/bbl for front-month ICE Brent to below USD 46/bbl in January. NYMEX WTI saw similar declines. The drop came on the heels of a pronounced slowdown in demand growth – with year-on-year gains of just 0.3 mb/d in 2Q14, a near five-year low – and record advances in non-OPEC supply. It gained momentum around October, with Brent falling by more than USD 5/bbl in a single day, on 27 November, when OPEC surprised the market by keeping its production target unchanged in the face of falling revenues and rising non-OPEC supply. Prices dropped further still in December and through most of January, but in the latter part of the month appeared to stabilise before recovering to above USD 50/bbl in early February. As prompt prices fell, the futures curve shifted into a pronounced contango, a price structure where prompt supply trades at a discount to barrels for later delivery, usually indicative of a well-supplied, or even oversupplied, market.

**Figure ES.2** Historical Brent crude oil prices

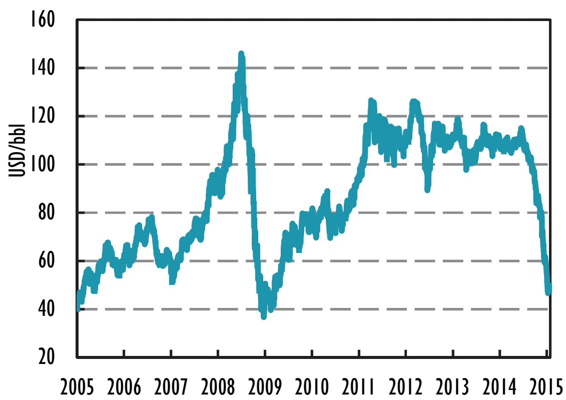
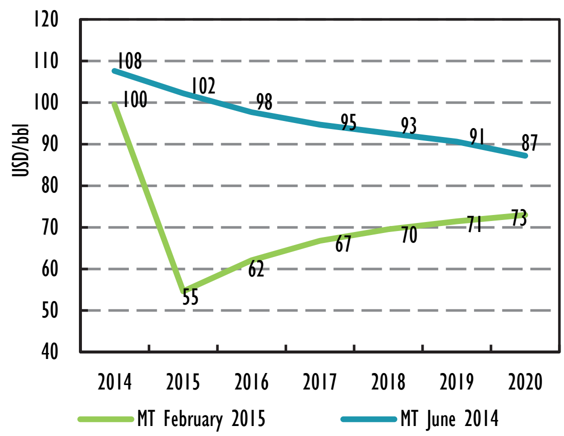



**Figure ES.3** IEA import price assumptions



As with previous editions of this *Report*, the price *assumptions* (not forecasts) used as modelling input are derived from the futures curve. These averaged roughly USD 55/bbl for 2015, ramping up gradually to USD 73/bbl in 2020. These prices suggest that participants expect the market to recover somewhat as it rebalances following cuts in upstream investment. Despite that improvement, the market does not seem to be expecting prices to revisit earlier highs any time soon. Not only have prompt prices collapsed, even price expectations for the back end of the curve have been significantly downgraded.

The futures market's record as price forecaster is of course notoriously mixed. But future prices represent the level at which market participants can hedge today and as such can meaningfully affect investment and business decisions over the next business cycle. It is also the basis of the price assumptions used by the International Monetary Fund (IMF) in its forecasts of economic growth, which in turn are used as input in this *Report*.

## Demand

The fact that lacklustre demand was part of the reason for the recent price collapse suggests that the selloff will only go so far in boosting economic growth and lifting oil demand. Indeed, the recent price decline is expected to have only a marginal impact on global demand growth for the remainder of the decade. Projections of oil-demand growth have been revised downwards, rather than upwards, since the price drop, in line with IMF forecasts of underlying economic growth; demand growth is expected to slow markedly, to 1.1 mb/d per annum over the next six years, from the "normal" pace of expansion exhibited prior to the financial crisis of 2008-2009.

As in previous editions of this *Report*, however, demand growth is still projected to gain momentum from recent lows as the global economy slowly improves, albeit more slowly than expected. Following cutbacks in upstream investment, it is now forecast to run ahead of supply gains by as much as 1 mb/d over the next six years, resulting in significantly tighter balances by the beginning of the next decade.

Oil exporting economies, which in recent years had been a driving force behind oil demand growth, will for the most part be adversely affected by the oil price drops, with the notable exception of Gulf Cooperation Council (GCC) countries with large enough buffers to absorb the impact of the revenue shortfall; Russia, where international sanctions will compound the effect of plummeting fiscal and export revenues, will be particularly hard hit. But the reverse might not be as true of oil-importing countries as would be expected. For most oil importers, the benefit of rising disposable income and lower production costs will be partly offset by underlying problems in the broader economy. In several large OECD economies, falling prices may feed into deflationary expectations, boosting savings ratios and in that sense exacerbating downward pressures on the economy. In many cases, weak currencies will blunt the impact of the decline in dollar-denominated oil prices, while governments rightfully take advantage of lower international oil prices to unwind costly subsidy programmes. End-users might not see as much relief from the drops as it would appear.

The fact that the global economy has become less oil-intensive than in the past, coupled with the diminishing role of oil in the fuel mix, will further mute the demand impact of lower prices. China's reorientation away from heavy manufacturing and exports towards a more consumer-driven economy puts a crimp on what had been the leading engine of global oil demand growth for the last 15 years. Beijing's efforts to fix its crippling air-pollution problems through efficiency gains and cleaner-burning fuels will add to the de-emphasis on export-driven industries and construction-led growth. In part due to the legacy of years of sustained record-high oil prices, the world has become in general much less oil-intensive, and oil's place in the fuel mix is eroding. Mature OECD markets will see protracted contraction in oil demand in the years to 2020, extending earlier trends. But the rest of the world is no longer expected to provide as strong an offset as in the past. Renewables and natural gas are increasingly price-competitive against oil and coal in emerging markets and will continue to encroach – whether directly or indirectly – on oil consumption. Non-OECD oil demand is only expected to grow by 1.19 mb/d annually in the years to 2020, far less than its historical rate of growth.

## Bunkers

Changing regulations for marine bunkers provide an example of how policy measures can undermine oil-demand growth at the margin even in the face of falling oil prices. The marine industry had long been one of the last strongholds of high-sulphur residual fuel oil (RFO) demand, but international regulations are catching up with the sector and the International Maritime Organisation (IMO) plans to lower sulphur emissions from marine bunkers as of 2020 (or 2025 if it opts to delay implementation).

The new rules will greatly lighten the quality of the global demand barrel as most shippers – but not all – are expected to switch from RFO to lower-sulphur marine gasoil to meet the tighter standards. Given the volumes involved, however, at least some shippers will have to adopt alternative options – including burning RFO with abatement technology (scrubbers) and switching to liquefied natural gas. Should all high-sulphur bunkers be replaced with marine gasoil, large new investments would be needed for the refining industry, on top of those already announced, to achieve the required changes in its product slate.

## Supply

Supply-capacity growth looks significantly lower than expected in the years to 2020 as lower prices slash investments. Despite a plunge in oil prices of more than 50%, however, global capacity is still expected to increase to 103.2 mb/d over the next six years, a 5.2 mb/d gain. Two thirds of this growth will come from non-OPEC producers. Despite OPEC's stated policy of defending market share, its own crude capacity is only projected to gain 1.2 mb/d, an average of 200 kb/d per annum. Iraq alone accounts for almost all of the increment, as other producers curtail spending or struggle with low prices and security issues. Non-OPEC supply is forecast to reach 60 mb/d by 2020, with growth slowing to an average annual 570 kb/d. That growth rate is far below the record gains of 1.9 mb/d in 2014, and down from an average 1 mb/d in 2008-13.

Remarkably, US LTO is expected to remain a top source of incremental supply, with growth initially slowing to a trickle but swiftly regaining momentum later on, bringing production to a projected 5.2 mb/d by 2020. Although questions remain about the availability of capital to LTO producers on the rebound, on balance LTO investment cutbacks are not expected to have as long-lasting an impact as other spending cuts. Russia, facing a perfect storm of collapsing prices, international sanctions and currency depreciation, will likely emerge as the industry's top loser. Its production now looks set to contract by 560 kb/d from 2014 to 2020. Other cuts will target big-ticket items, such as high-cost deep-water projects in West Africa and elsewhere, as well as routine field maintenance as producers seek to squeeze as many barrels as possible from producing fields, resulting in faster decline rates later on. That will leave North American unconventional production looming even larger in total supply than previously thought.

Rising US LTO supply, another major factor behind the recent price drops, has often been described as a "game changer", including in earlier editions of this *Report.* But its transformative impact does not derive just from the sheer production volumes it has unlocked, and which today have made it the world's top source of incremental supply. LTO also looks set to stand out by its responsiveness to lower prices. Its short lead and pay-back times, rapid well-level decline rates and treadmill-like investment requirements make it far more price elastic than conventional crude. Price declines have already caused the US LTO rig count to drop abruptly, setting the stage for a significantly faster supply response than would be typically expected from conventional crude producers.

OPEC's historic move to refrain from cutting production at its November 2014 meeting has thus turned LTO into a critical balancing factor. While it is not exactly unprecedented for the producer group to leave it to others to balance the market, one has to go as far back as 1986 for a prior and single example of such a move. An unexpected consequence of the North American supply revolution is thus to have effectively undercut, if not overturned, traditional OPEC and non-OPEC roles.

## Biofuels

In addition to providing most of the world's new liquid hydrocarbon supply, the Americas also remain the leading source of renewable fuels, particularly ethanol. While lower oil prices may theoretically cause biofuels to grow less competitive against hydrocarbon fuels in mature markets, in practice production is expected to remain unaffected as biofuel consumption remains largely mandate-driven. Demand growth in the United States, Brazil and even the European Union appears to be running out of steam, but new mandates in Asia – largely a lagged legacy of years of record-high oil prices, growing oil-import bills and oil-subsidy costs – is picking up the slack. Indeed, world biofuel production is projected to rise slightly faster than previously expected, reaching 2.4 mb/d by 2020, up from roughly 2.2 mb/d in 2014.

## Crude and product trade

Shifts in supply and demand dynamics may slow previously expected refinery trends and trade flows but will not cause them to materially change course. With LTO price elasticity keeping the United States firmly in its role as major provider of oil supply growth, North America will continue to source more of its crude locally, thus backing out seaborne imports, even as China – despite some significant scaling back – and the Middle East continue to ramp up refinery throughputs.

The net result of those upstream and downstream changes will be a continued shift of the global oil market from crude to products, with contraction and fragmentation in crude markets mirrored by expansion and globalisation in product markets. New forms of inter-dependence between oil exporters and importers will emerge. The hollowing out of the European refining industry amid growing competition from North America, India, China, Russia and the Middle East will leave Europe increasingly import-dependent for its middle-distillate needs – even as tightening sulphur standards for marine bunker fuels look set to dramatically boost those requirements. China and the Middle East, meanwhile, will become locked in a tightening embrace, but thanks to diminishing crude-import demand in North America and Europe, Asian buyers will enjoy unprecedented buying power as crude exporters will be forced to compete more aggressively in the same Asian markets.

Trends in the tanker industry will closely track those in crude and product markets. Most of the growth in the global tanker fleet will come from clean product tankers, including relatively large vessels designed to provide economies of scale in a market long confined to relatively short-haul trade and small ships. The average crude tanker is also getting larger in size as the average voyage grows longer, in a bid to make long-haul trade from the Atlantic Basin to Asia, which is on the rise, more economical.

## Refining and product supply

Meanwhile the global refining industry continues to reinvent itself. Expansions continue, with capacity set to rise by 6.4 mb/d by 2020 to 102.1 mb/d, slightly more slowly than previously forecast, as China, in particular, scales back some projects in the face of weaker-than-expected domestic demand growth. Most of the capacity growth takes place east of Suez, with emerging Asia (including China) in the lead, followed by the Middle East.

Although refining capacity growth closely tracks demand growth, in practice excess refining capacity looks set to grow, as up to one third of incremental product demand is expected to be met by liquids that will bypass the refining system altogether such as natural gas liquids, biofuels, gas-to-liquids and coal-to-liquids. As such, refinery margins are expected to remain under pressure and further capacity rationalisation in mature markets looks inevitable, as product flows from new start-ups hit the market.

# 1. DEMAND

## Summary


- **Global oil demand growth is forecast to average 1.2% per annum in the run-up to 2020, up from the exceptionally slow progress of 2014**, but down significantly from prevailing growth rates prior to the financial crisis of 2008-09. A combination of structural and cyclical factors are holding growth down, including a weaker-than-expected economic recovery and lower long-run growth prospects across most of the world.

- **Steep declines in oil prices since June 2014 will have mixed effects on economic growth prospects across the world and on balance will provide at best a modest boost to global oil demand.** Expectations of global economic growth have been repeatedly revised downwards in the last six months despite steeply falling prices, slashing prior forecasts of oil demand growth for the rest of the decade by about 1.1 mb/d.

- **Fuel switching – to natural gas, nuclear, coal and renewables – is expected to cut global oil demand by roughly 2 mb/d by 2020.** The transport and power sectors account for the majority of this projected switch.

- **Chinese demand growth is expected to slow** to less than 300 kb/d annually in the years to 2020 following Beijing's decision to reorient the economy away from manufacturing/exports, down from average growth of 440 kb/d in 2009-14. Demand growth from other non-OECD Asian countries will consistently overtake China for the first time since the mid-1990s.

- **Russia's economy will contract in 2015-16, severely impacting domestic demand** there and in the Caucasus and Central Asia. Having expanded by around 3.3% per annum in 2008-14, Russian demand is projected to inch up by an average 0.5% annually over the next six years.

- **Political turmoil and sectarian strife will slow demand growth in the Middle East and North Africa, compounding the effect of lower oil export revenues.** Iraqi demand is projected to inch up by 10 kb/d annually in the next six years, down from 45 kb/d growth during 2008-14.


**Table 1.1** Global oil demand (mb/d), 2014-20

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2014-20 |
|---|---|---|---|---|---|---|---|---|
| **OECD Americas** | 24.1 | 24.2 | 24.3 | 24.4 | 24.5 | 24.4 | 24.4 | 0.3 |
| **OECD Asia Oceania** | 8.1 | 8.0 | 7.9 | 7.9 | 7.9 | 7.9 | 7.8 | -0.3 |
| **OECD Europe** | 13.4 | 13.3 | 13.3 | 13.2 | 13.1 | 13.0 | 12.9 | -0.5 |
| **FSU** | 4.8 | 4.6 | 4.7 | 4.7 | 4.8 | 4.9 | 5.0 | 0.1 |
| **Other Europe** | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.1 |
| **China** | 10.4 | 10.6 | 10.9 | 11.2 | 11.5 | 11.8 | 12.1 | 1.7 |
| **Other Asia** | 12.1 | 12.5 | 12.9 | 13.3 | 13.7 | 14.1 | 14.5 | 2.4 |
| **Latin America** | 6.8 | 6.9 | 7.0 | 7.1 | 7.2 | 7.3 | 7.4 | 0.6 |
| **Middle East** | 8.1 | 8.3 | 8.5 | 8.8 | 9.0 | 9.2 | 9.5 | 1.4 |
| **Africa** | 3.9 | 4.1 | 4.2 | 4.4 | 4.5 | 4.6 | 4.8 | 0.9 |
| **World** | **92.4** | **93.3** | **94.5** | **95.7** | **96.9** | **98.0** | **99.1** | **6.6** |

- **The centre of gravity of oil demand continues to move east.** Non-OECD economies, driven by Asia, overtook the OECD for the first time in 2014. Overall, Asia, including both OECD and non-OECD countries, replaces the Americas as the world's largest consuming region in 2015.

- **Aggregate oil demand growth, of around 6.6 mb/d in 2014-20, exceeds projected capacity growth by around 1.5 mb/d.**

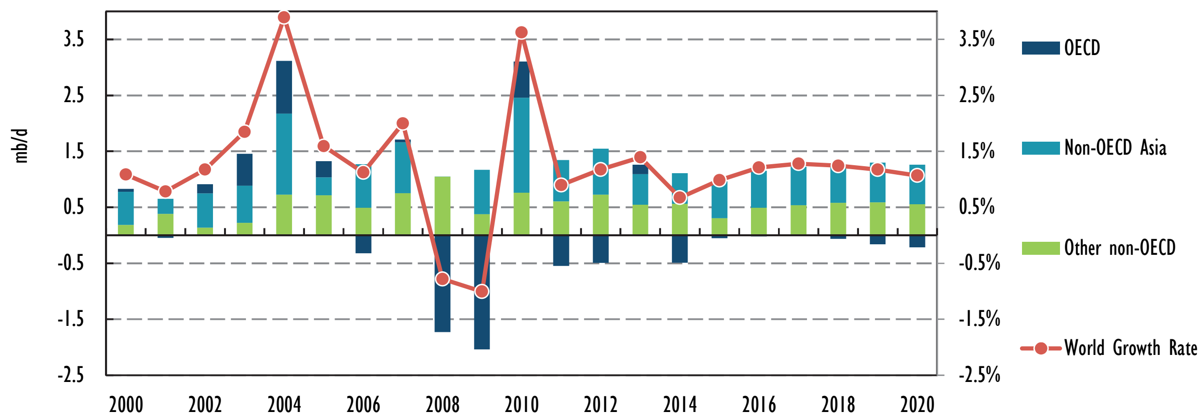
- **New bunker fuel regulations, due to take effect in 2020, will dramatically lighten the demand barrel.** New air-emission limits for the shipping industry will first lift middle-distillate demand at the expense of heavy residual fuel oil by 0.2 mb/d in 2015, and then again potentially by more than 2 mb/d by 2020 if the new regulations come into effect.

## Overview

Global oil demand growth is expected to recover in the years to 2020 from exceptionally weak gains in 2014, but to lag the stronger rates experienced prior to the financial crisis of 2008-09. An oil market selloff since June 2014, resulting in dramatically lower spot crude and product prices and lower future prices, is expected to have a mixed impact on economic growth, but overall to provide only a modest net boost to global oil demand. For the next six years, global demand growth is projected to average 1.2% per annum, below its pre-Great Recession trend (1.9%, 2001-07), taking global oil product demand up to around 99.1 mb/d by 2020. This represents aggregate demand growth of 6.6 mb/d for the six-year period, notably nearly 1.5 mb/d more than the 5.2 mb/d growth projected in global oil supply capacity.

On balance, expectations of world oil product demand growth are more subdued than prior to the recent oil price drop. A combination of cyclical and structural factors stand behind this softer demand outlook, including, but not limited to, significantly reduced expectations of global economic growth for the early part of the forecast period. Towards the latter part of the forecast, a structurally-driven reduction in the oil intensity of the global economy, supported in part by fuel switching out of oil and increased energy efficiency, somewhat blunts the demand impact of forecast economic growth.

**Figure 1.1** Global oil demand growth, 2000-20




Economic growth projections, a major input in oil demand forecasts, have been repeatedly downgraded since mid-2014. Since the early July 2014 release of its *World Economic Outlook* (*WEO*), the International Monetary Fund (IMF) revised its growth projections for 2015 and 2016 downwards twice, first in October 2014 and again in January 2015. Global growth is still expected to rise in 2015-16, compared to 2014, but more moderately than previously expected, reflecting what the IMF described as a "strong undertow" of lower long-run prospects. Growth is now projected to rise from 3.3% in 2014 to 3.5% in 2015 (versus 4.0% in July's *WEO*) and 3.7% in 2016.

**Table 1.2** Global GDP growth forecast, 2014-20

| | *MTOMR 2015* | IMF January 2015 | IMF October 2014 | IMF July 2014 |
|---|---|---|---|---|
| **2014** | 3.3 | 3.3 | 3.3 | 3.4 |
| **2015** | 3.5 | 3.5 | 3.8 | 4.0 |
| **2016** | 3.7 | 3.7 | 4.0 | - |
| **2017** | 3.7 | - | 4.1 | - |
| **2018** | 3.7 | - | 4.0 | - |
| **2019** | 3.8 | - | 4.0 | - |
| **2020** | 3.8 | - | - | - |

Sources: IEA; International Monetary Fund, *World Economic Outlook*.

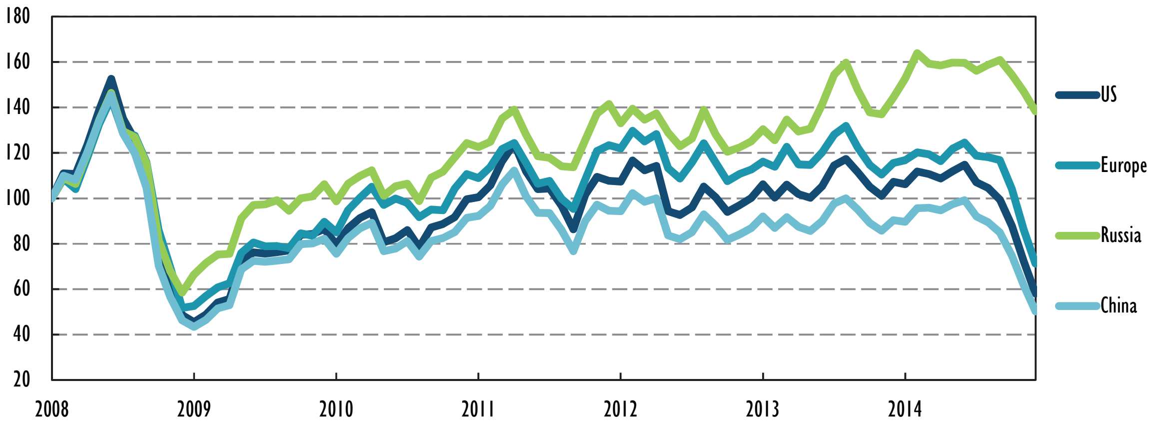
Oil prices have plunged since their June 2014 peak, resulting in dramatically lower price assumptions in this edition of the *Medium-Term Oil Market Report* (*MTOMR*) than in *MTOMR 2014*. Price inputs are based on the futures curve as of January 2015, with average crude prices of 55 USD/barrel for 2015 and just over 60 USD/barrel for 2016, rising steadily above 70 USD/barrel in 2020. This compares with *MTOMR 2014* price assumptions of roughly USD 100/barrel in 2015 and 2016, falling to just below USD 90/barrel in 2020. While the futures curve is at best an imperfect forecaster of oil prices, it does represent the level at which market participants can hedge. The relatively steep contango in the futures curve – a market structure where prompt barrels trade at a discount to longer-term supply – appears to reflect both short-term oversupply and longer-term expectations of a decline in investment and future capacity. However, even longer-term price expectations have been significantly reduced since *MTOMR 2014*, with 20 USD/barrel removed from the 2019 price. While participants expect the market to rebalance in response to low-price signals, reduced long-run price expectations reflect the perception that the oil market has undergone a long-term structural shift marked by deep-seated changes in supply and demand dynamics.

While price effects on economic growth and oil demand will vary greatly country by country, their net impact will be more modest than might be expected. Generally speaking, lower oil prices are a negative for oil-exporting countries, undermining export and fiscal revenues, with knock-on effects on government spending and non-oil economic growth, and a positive in oil-importing economies, lifting disposable income and cutting input costs, while at the same time lowering oil-import and subsidy bills. In practice, things are more complicated. Adverse effects on oil-exporting countries will be less severe in those countries that enjoy large buffers and available financing – such as most oil Gulf Cooperation Council (GCC) countries – but more pronounced where such buffers are non-existent and lower prices may take a toll on social spending, resulting in higher social and political instability. They will be especially debilitating in Russia, compounded as they are by the impact of international sanctions, and by extension on Caucasus and Central Asian countries that are highly dependent on Russian external demand, remittances and foreign direct investment. On balance, impacts on oil demand in oil-exporting countries – which in recent years had accounted for a very large share of global demand growth – will be a clear negative.

Upward price effects on demand in oil-importing countries, meanwhile, will be varied and may not significantly offset downward effects elsewhere, at least initially. In large part, positive price effects on oil-importing economies will be muted by what the IMF calls "persistent negative forces," such as the "lingering legacies" of the Great Recession of 2008-09 and weak investment as many countries adjust to lower potential growth. It is important to note that recent crude oil price declines were both supply- and demand-driven: to a large extent, it is the dramatic slowdown in global oil demand from 3Q13 to 2Q14 that caused oil prices to collapse from June 2014 onwards. Oil-price declines against a backdrop of slowing demand growth will not be as potent an economic stimulus as they would be in a context of strong underlying income gains.

In most consuming countries, currency fluctuations have also blunted the benefit of lower dollar-denominated crude oil prices. The US dollar has appreciated by approximately 15%, over the six months through to January 2015, even as the euro and the Japanese yen depreciated by similar amounts. In many emerging-market economies, currency swings have been even more severe. The Russian rouble has lost over 40% of its value since June 2014. Converted into roubles, for example, international crude prices have fallen by around one-eighth, versus the near 60% decline in US dollar terms.

**Figure 1.2** Domestically-prices Brent crude indices, 2008-14




Compounding the effect of currency swings, many non-OECD, oil-importing countries have taken advantage of the recent drops in international oil prices to cut their oil subsidy programmes or raise oil consumption taxes. While this is sound policy, it also has contributed to deprive end-users from the full benefit of price declines.

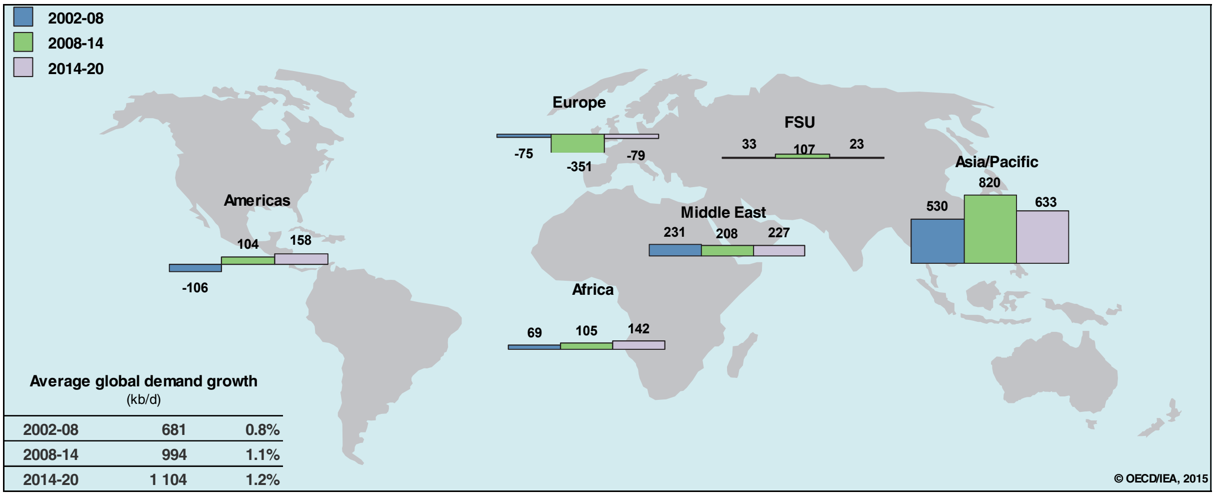
Meanwhile in many developed economies, particularly Japan and much of Europe, deflationary pressures are providing an economic environment in which oil price drops may adversely affect economic growth and oil demand by feeding into deflation expectations. In previous corrections, cheaper oil curbed inflationary pressures. This, in turn, prompted lower interest rates and stimulated demand. In a deflationary/low-inflationary world, however, particularly one where interest rates are already negligible, this possibility is negated. Indeed, falling oil prices may compound the already high risk of deflation, potentially dampening economic activity as consumers and businesses conceivably put off today's purchasing decisions in the expectations of lower prices in the future.

Most recent research suggests that the global economy is becoming less oil-price elastic, so that ever larger price drops are needed to generate a constant percentage gain in oil demand. This in part reflects the lagged impact of earlier price shocks. Price effects on demand are highly asymmetrical: effects from upward price changes tend to be "stickier" than lower-price effects. The history of the oil market shows that price shocks such as those experienced in the 1970s and 1980s triggered long-lasting demand losses and/or gains in oil efficiency. Recent price drops have come on the heels of several years of sustained record-high oil prices, and to some degree may reflect a lasting demand response to that prolonged period of elevated prices, the effect of which may be entrenched for the longer term.

But the diminishing price elasticity of global oil demand also reflects other long-run structural market changes, including steady advances in energy efficiency, increased inter-fuel competition from natural gas and renewables, and the greater share of the service industry and other non-oil-intensive sectors in the global economy. Nowhere is this shift to a less oil-intensive stage of economic development more apparent than in China, a country that in recent years accounted for just under 35% of aggregate oil demand growth, but whose share of incremental demand is expected to drop to around one-quarter in the next few years to 2020.

Despite such a precarious backdrop, the net 6.6 mb/d demand growth forecast, 2014-20, remains sizeable and contains an important geographical swing: away from Europe and towards Asia and the Middle East. Through the forecast, Asia (OECD plus non-OECD) accounts for 57.4% of the projected net gain, followed by the Middle East (20.6%), the Americas (OECD plus non-OECD, at 14.3%) and Africa (12.8%).

**Map 1.1** Oil demand growth, average per annum growth, kb/d




This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Falling oil prices also provide a potential downside-trigger to the sustainability of the projected macroeconomic recovery. 'Energy and materials' companies made up roughly one-third of the total US high-yield bond index in 2014, up sharply from the 18% share of 2010. This is not to say that a mass default on this debt is expected, but to highlight the potentially large scale of exposure that exists today. The cost of capital to oil producing companies/countries has accordingly risen, reflecting escalating risk premiums. Dampening such fears, however, it is important to remember that the 'energy and materials' sub-component of the bond index amounts to significantly more than high-cost oil producers. Furthermore, the Great-Recession of 2008-09 was, at least partially, attributable to collapsing property prices in the United States, a sector that it was even more exposed to.

Deteriorating geopolitical conditions in the economies of the former Soviet Union and the Middle East add a further downside burden on oil demand forecasts, as to a lesser degree are the ongoing troubles in many African nations. For example, compared to 2019, the last time period directly comparable with last year's *Report*, roughly one-third of the reduced global demand estimate is attributable to the former Soviet Union, 52.7% the Middle East and 10.6% Africa. This is a change from the normal spin put on geopolitical tensions being mostly a supply-side risk, as we acknowledge here that they also adversely affect economic growth and oil demand. In fact, the history of international relations (wars, etc.) is intimately associated with economic growth patterns. Thus, the deteriorating geopolitical environment weighs on demand prospects and the proliferation of regional crises could usher in a long economic winter. The deadlock in Russian/western relations over Ukraine raises the prospects of a long-term cooling of trade and economic activity which would adversely affect growth not only in Russia but in neighbouring economies and the EU. The IMF, in January, forecast that the Russian economy would contract by 3% in 2015, while the Commonwealth of Independent States was expected to contract by 1.4%. This *Report* assumes that sanctions remain in place through the forecast period, hence resulting in relatively slow demand growth in affected regions. Of course, a reversal of such sanctions would provide an additional fillip to demand.

## OECD demand

OECD economies accounted for 49% of global oil demand in 2014, a share expected to drop to around 46% by 2020. OECD demand peaked in 2005 at 50.4 mb/d and is projected to drop through the forecast to 45.1 mb/d by 2020. While the shift to non-OECD is consistent with previous forecasts, it is occurring more slowly than previously projected, due to lower-than-expected demand growth in China and curbed demand forecasts for net oil-exporting economies such as Russia and the Middle East.

The OECD group of economies is showing divergent patterns in oil demand, reflecting underlying differences in economic growth: the United States depicts strong economic growth, high income gains, falling unemployment, and signs of oil demand growth – versus extremely weak growth and underperformance in Japan, persistent high unemployment and tepid growth in Europe, and deflationary pressures in Europe and Japan. The OECD Americas forecast sees modest oil demand growth of around 0.2% per annum, 2014-20, in contrast to OECD Europe which falls by a forecast per annum rate of 0.7% and OECD Asia Oceania, down by around 0.6% per annum.

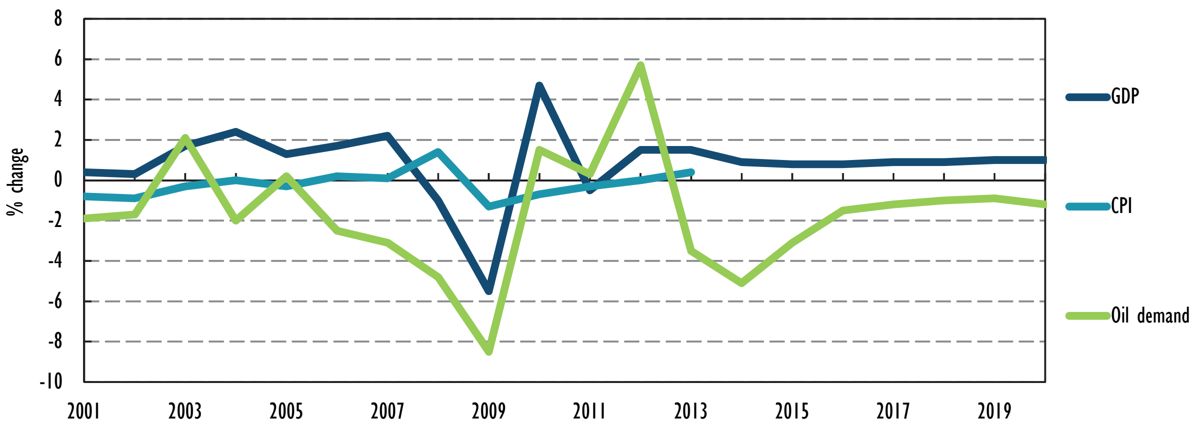
**Table 1.3** OECD oil demand (mb/d), 2014-20

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2014-20 |
|---|---|---|---|---|---|---|---|---|
| OECD Americas | 24.1 | 24.2 | 24.3 | 24.4 | 24.5 | 24.4 | 24.4 | 0.3 |
| OECD Asia Oceania | 8.1 | 8.0 | 7.9 | 7.9 | 7.9 | 7.8 | 7.8 | -0.3 |
| OECD Europe | 13.4 | 13.3 | 13.3 | 13.2 | 13.1 | 13.0 | 12.9 | -0.5 |
| **OECD** | **45.6** | **45.6** | **45.6** | **45.5** | **45.5** | **45.3** | **45.1** | **-0.5** |

**Cyclical drivers of OECD demand contraction.** Divergences in the pace of demand growth across the OECD largely reflect variations in the economic cycle between regions, with the United States growing and the rest of the OECD stagnating. But there are many structural reasons why oil demand has peaked in general in the OECD. Broadly speaking, these are mature markets where oil penetration is already high, efficiency is on the rise and energy consumption patterns increasingly moving away from oil.

The economic recovery continues to be marginally weaker than expected. Until now, this has just led to growth expectations being pushed back but not significantly altered: the IMF, for example, has pushed back forecasts, but the basic narrative of 'better tomorrows' has been roughly unchanged. The fact that several large economies are flirting with deflation (combined with/due to underlying factors such as low or negative wage growth, etc.) could change everything. This would mean the economy is at risk of falling into a liquidity trap with two consequences for oil demand. First, economic growth would remain relatively weak and due to its weakness, fail to support anything other than moderate oil demand growth. Second, part of the economic impact of lower oil prices would be reversed: instead of acting as a "tax break" and stimulating economic growth, low oil prices would exacerbate deflationary expectations and undermine investment and consumer spending, and thus demand. There could be a long cycle of weak economic and demand growth.

**Figure 1.3** Deflationary pressures and their impact upon oil demand and economic growth, the Japanese experience



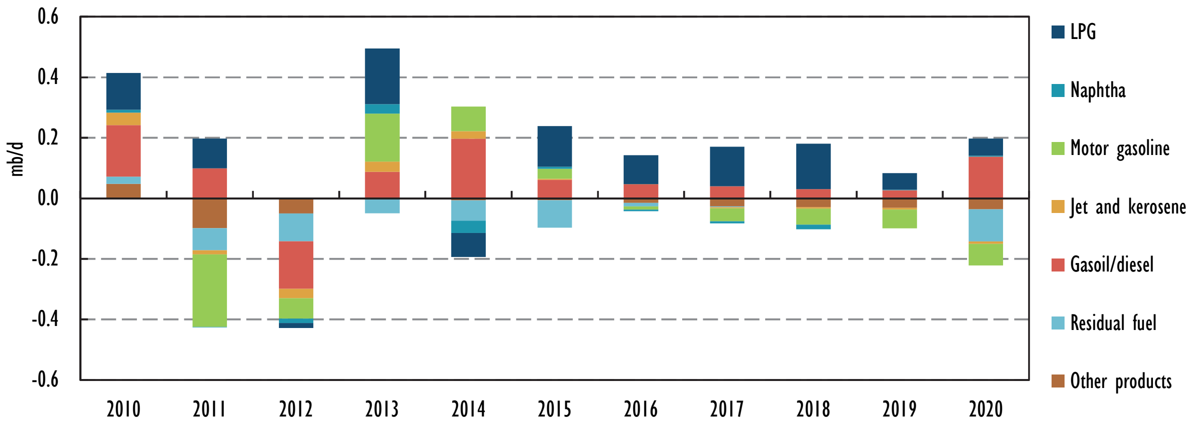

Escalating deflationary pressures, particularly in Europe and Japan, threaten to dampen the economic outlook, as consumers put off purchasing decisions in the expectation of lower future prices, triggering a self-fulfilling spiral of weakening macroeconomic conditions. The Japanese experience provides some evidence of how deflation can come with weak oil demand, as falling consumer prices in three distinct periods – 2001-03; 2005; and 2009-11 – coincided with absolute oil demand declines in all bar one occasion. Even the one exception, i.e. 2005, was essentially consistent with flat demand, and the absolute drop in consumer prices in 2005 was very moderate (down 0.3%) anyway. The most recent deflationary experience, i.e. 2009-11, coincided with the bleakest relative demand performance, as oil demand fell by an average of 2% y-o-y. If lower oil prices, post-2014, cause a general elongation of these pressures then accordingly much weaker economic growth could result, dampening prospective oil demand. Our forecasts are already somewhat constrained by such pressures, but in a doomsday scenario in which these deflationary forces escalate it is not inconceivable that demand would be considerably lower.

**Structural drivers of OECD demand contraction.** Changing technologies and tightening environmental constraints are combining to create a 'new age' of lower oil demand growth and diminishing oil intensity, where less oil is required to produce a comparable amount of economic output. These changes have considerably distorted pre-existing linkages between economic growth and oil consumption, hence the weaker projections that are carried for oil demand growth.

Changing consumer preferences are helping to drive the OECD's move away from oil. Changing demographics, improved city-design, tightening environmental legislations, changing vehicle technology and the IT revolution have all contributed towards dramatic improvements in efficiencies, altering consumer behaviour in a way that reduces oil consumption. The next five years are forecast as seeing a continuation of the dramatic recent developments.

Vehicle efficiency standards, such as the US Corporate Average Fuel Economy (CAFE) standards (see Box 1.1, *Impending efficiency gains to curb prospective oil demand*), lay at the heart of the generally declining OECD demand trend. OECD gasoline demand is falling by approximately 0.6% per annum, 2014-20, equivalent to a net decline of around 0.5 mb/d, while OECD diesel demand (not exclusively used on roads) inches up by 0.3 mb/d, 2014-20. Projections of product switching, largely to natural gas-powered vehicles (NGV) but also to electric-powered vehicles, also curb OECD oil demand forecasts, although only at the margin through 2020.

**Figure 1.4** US oil demand growth, 2010-20



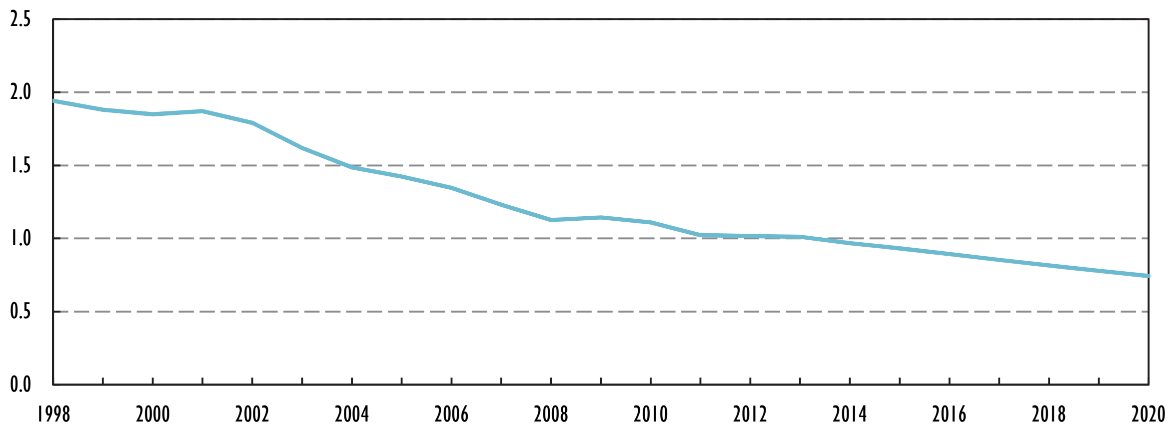

In the United States, where gasoline accounts for roughly one in every ten barrels of oil consumed globally, an average decline rate of approximately 0.4% per annum is forecast, 2014-20, equivalent to a net decline of 0.2 mb/d over the six year period. Some temporary demand support is envisaged in 2015, before an accelerating reversal takes hold, 2017-20, as the IEA's *Energy Demand Technology* (EDT) unit envisages near 4% per annum efficiency gains across the passenger-light duty vehicle (PLDV) fleet. Diesel demand in the United States is forecast to hold up better, rising by an average 0.7% through the forecast, to 4.0 mb/d in 2020, as additional industrial impetus likely remains sufficient to offset freight efficiency gains. An element of product-switching to NGV's trims the forecast at the margin, with city bus services, couriers and refuse collection all projected to see some switch.

Europe and OECD Asia Oceania face similar, but sharper downside pressures, respectively posting net 0.5 mb/d and 0.3 mb/d declines through to the next six years. Weaker macroeconomic growth trends, coupled with more heavily aging population bases and frailer industrial outlooks, trim their respective forecasts. Sharp declines in road transport fuel demand, across both regions, lead the projected downside consequential on continued vehicle efficiency gains of around 2% to 3% per annum, 2014-20.

The changing demographics of many OECD nations further curb the demand outlook, as retired workers traditionally demand less oil products. In Germany, for example, those categorised as 'old' made up 21% of the population in 2013, up dramatically on 2000's 16% share, with similar trends seen across most OECD nations. Falling birth rates and improving healthcare are likely to support the continuation of the aging-OECD populations through to the end of the decade. As more cities clean-up their city centres and improve transport links, this further dampens the demand outlook.

Computerised enhancements, coupled with the ongoing evolution that is occurring in consumer trends, act as an additional constraint on oil product demand. At the turn of the century, the OECD oil intensity was a relatively stationary 1.9, hence approximately two barrels of oil were required globally to produce a standard unit of economic activity (see Box 1.1, *Impending efficiency gains to curb prospective oil demand*). Along with general improvements in vehicle efficiencies, changing demographics and fluctuating consumption trends, advancements in communication technologies/connectivity saw the oil intensity halved, 2001-14. A similarly paced decline is foreseen over the next six years.

**Figure 1.5** OECD oil intensity, 1998-2020



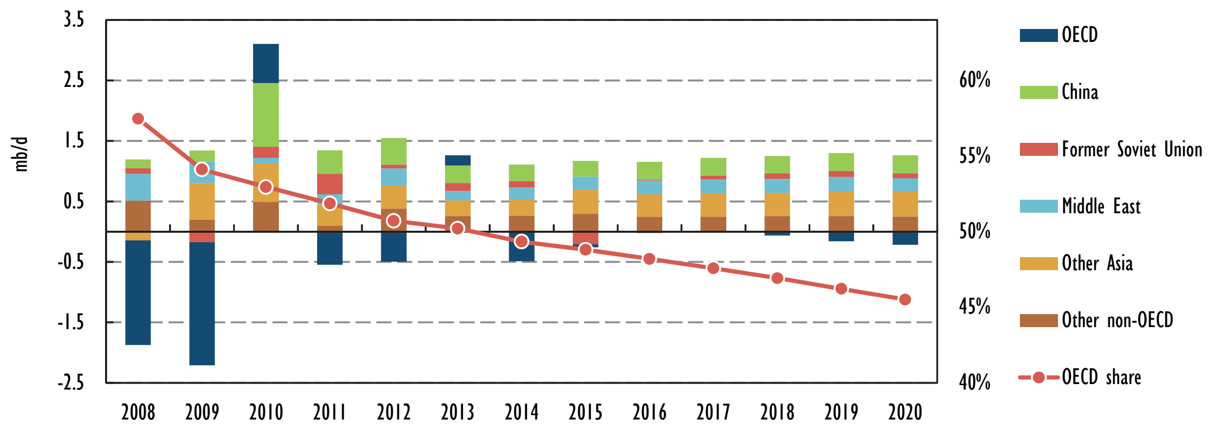

Consumer purchases will no longer include as many miles spent-in-vehicle, travelling between shops, searching for parking spots, etc., as product research/browsing, price comparisons and even purchases will be made online, and to an increasing degree through to 2020. A quick snapshot of recent retail sales trends in the United States showed Thanksgiving weekend sales down 6.4% on the year earlier, according to the National Retail Federation, versus the near one-third increase in online sales quoted by comScore. Statistics Portal reports over 115% growth in smartphone sales in the United States, 2010-13, roughly three times the pace of growth in new vehicles, although statistics can sometimes be misleading as second-hand usage of mobile telecommunications vastly dwarfs vehicles.

Regardless of IT developments, actual physically delivery of products, from store to consumer, will still requires vehicle transportation, but even these can potentially be more efficiently planned by courier services that package products together, further curbing projected oil demand growth.

## Non-OECD demand: lower oil prices provide only modest support

Non-OECD demand growth is expected to more than offset overall contraction in the OECD through the rest of the decade, extending earlier trends. The pace of non-OECD growth will be more subdued than previously expected. The distribution of incremental demand among regions will also differ from earlier patterns, with significantly slower Chinese consumption gains forecast. Earlier expectations that non-OECD demand growth would continue unabated and replicate the growth patterns exhibited by more mature economies at earlier stages of development have been proven wrong. For example, much of the oil consumption that was essentially 'wasted', as highly inefficient early-stage development vehicles consumed vast swathes of gasoline, diesel and jet fuel, can be preserved by the engine-efficiency developments that have already evolved. In many ways, recent non-OECD demand growth patterns show emerging-market economies cutting their own path of development and leap-frogging OECD economies in their developments. Advances in solar, wind and hydro technology have improved the competitiveness and market penetration of renewable fuels, allowing non-OECD economies to raise the share of renewables in their fuel mix at an earlier stage of development than had been possible for more advanced economies. The globalisation of the natural gas market and the growing preference for cleaner-burning fuels are also undermining oil demand in a new way.

**Figure 1.6** Oil demand growth, 2008-20




Against this backdrop, recent price declines are expected to provide only a moderate boost to non-OECD demand growth for the remainder of the decade. An average per annum non-OECD gain of 2.4% is foreseen, 2014-20, well below the previous mid-3% trend. Much weaker gains are forecast across the oil-rich regions, such as Latin America, the Middle East and the former Soviet Union, the latter two also having inhibited demand outlooks on escalating geopolitical tensions. China's evolution from a manufacturing/export-orientated economy to one increasingly focussed on domestic demand and environmental control has further compounded the situation. Chinese demand is expected to grow 2.6% per annum (2014-20), roughly half its previous six-year trend.

Recent moves in China show the government clearly targeting a serious climate change agenda, a strategy that it has undertaken in accordance with its five-year planning schedules. The twelfth Five-Year Plan (FYP), for 2011-15, embarked upon a tougher stance with regard to pollution controls and restraining energy use. Three of the seven key strategic targets concerned energy, with an explicit aim of reducing energy use by 16% per unit of GDP, 2011-15, alongside a 17% reduction in carbon dioxide emissions. The twelfth FYP also encompassed the target of raising non-fossil fuel energy consumption to 15% of the energy mix by 2020. Moving into the second half of this decade, the thirteenth FYP, for 2016-20, is forecast as tightening the clean energy objective, a factor that contributes heavily to this *Report's* relatively subdued Chinese growth forecast (see *China shifts gears*).

Non-OECD oil demand overtook the OECD in 2014, and the gap between the two will steadily widen henceforth, but expectations that moving forward non-OECD demand will follow OECD patterns of growth are misguided. One simply cannot extrapolate from past experience (historical patterns of oil demand versus GDP per capita in mature and newly industrialised economies) to project future demand from emerging markets. The broader technological and economic context has changed, and this changes everything. Numerous regional specific issues exist which we outline in detail below. For example, a sea change in retail pricing has occurred, whereby many non-OECD consumers face rapidly changing subsidisation/taxation structures. Also recent developments in IT have ensured that communications have gone, and will continue to go, virtual rather than physical, meaning less oil products are used to create the same amount of economic activity that would otherwise have been the case. Additional changes and developments, such as already-entrenched possibilities for very efficient oil use and fuel switching, further dampen the potential path of oil demand growth, as does China's shift to a 'lower-gear' of economic growth alongside the government's deliberate effort to steer domestic energy demand increasingly away from oil towards alternatives such as natural gas, renewables and nuclear.

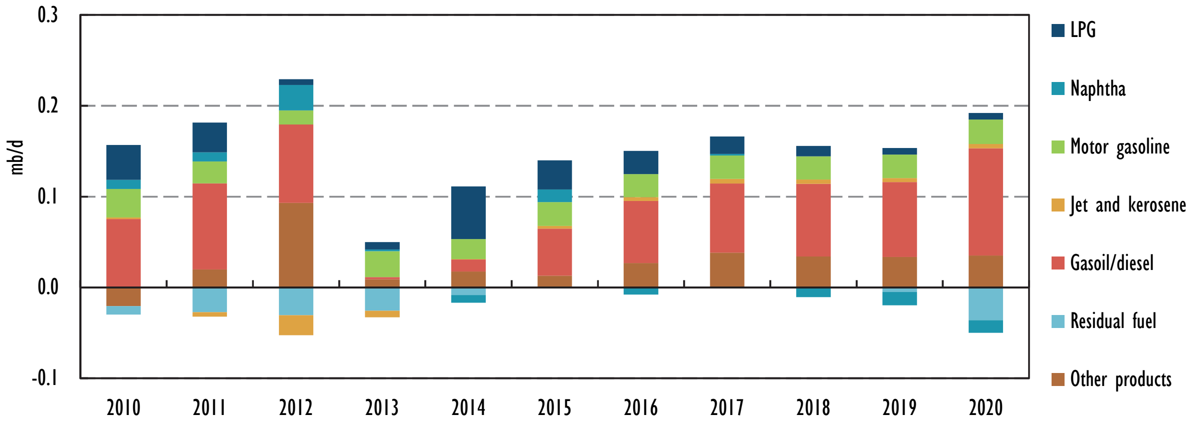
**Table 1.4** Non-OECD oil demand (mb/d), 2014-20

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Growth 2014-20 |
|---|---|---|---|---|---|---|---|---|
| LPG (including ethane) | 5.1 | 5.3 | 5.5 | 5.6 | 5.7 | 5.9 | 6.1 | 0.9 |
| Naphtha | 3.1 | 3.2 | 3.3 | 3.4 | 3.5 | 3.6 | 3.7 | 0.5 |
| Gasoline | 9.7 | 10.0 | 10.3 | 10.7 | 11.0 | 11.3 | 11.7 | 2.0 |
| Jet/kerosene | 3.0 | 3.0 | 3.1 | 3.2 | 3.3 | 3.4 | 3.5 | 0.5 |
| Gasoil/diesel | 14.1 | 14.4 | 14.7 | 15.1 | 15.4 | 15.8 | 17.8 | 3.7 |
| Residual fuel oil | 5.4 | 5.4 | 5.6 | 5.7 | 5.7 | 5.8 | 4.3 | -1.1 |
| Others | 6.3 | 6.4 | 6.5 | 6.6 | 6.7 | 6.9 | 7.0 | 0.7 |
| **Non-OECD** | **46.8** | **47.8** | **48.9** | **50.2** | **51.4** | **52.7** | **54.0** | **7.1** |

Outside of China, which is dealt with in detail in *China shifts gears*, a strong jump is foreseen in non-OECD Asia's second largest economy, India, where oil deliveries are forecast to rise to 4.7 mb/d in 2020 from approximately 3.9 mb/d in 2014, equating to a compound per annum growth rate of 3.4%. This forecast is faster than that carried last year, as despite the Indian economy's persistent reliance on still much less energy-intensive services for the majority of its economic growth, expectations of lower oil prices should stimulate additional transport fuel demand. Lower crude oil prices also significantly curb the import bill and hence support additional economic activity in heavily import-dependent economies such as India.

Transportation fuels provide the majority of this Indian demand growth, despite infrastructural constraints that the government is striving to address, as expectations of both rapid population and economic growth likely trigger strong gains in the absolute size of both the Indian passenger-vehicle and freight fleets. For example, India has unveiled plans to build a USD 6.5 billion, 1 800 km all-weather road, from Arunachal Pradesh to the border with Myanmar. Such developments open up the possibilities of motorised transportation to many previously isolated communities, accordingly increasing the number of people that can tangibly benefit from vehicle ownership. Demand in the gasoil/diesel sector, which accounts for roughly two of every five barrels consumed in India, is expected to grow by around 4.9% per annum through the forecast period. Gasoline demand is forecast to grow at an even faster clip, of 5.3% per annum, as the gradual elimination of diesel subsidies encourages some fuel switching to gasoline at the expense of diesel. Petrol and diesel prices have officially been de-regulated since 2014, but the government has since raised taxes on petroleum clouding the pass-through from lower international crude prices. At the extremity of the forecast, demand for non-road gasoil will also see some fuel switching to natural gas. Through 2020, India is forecast to enjoy better natural gas supplies than in recent years, including both domestically produced natural gas and imported LNG, undermining demand growth for refined products at the margin.

**Figure 1.7** India oil demand growth, 2010-20




In contrast with gasoil/diesel and gasoline, Indian demand for residual fuel oil and kerosene are expected to contract. With tightening global bunker fuel regulations cautiously anticipated for 2020, a particularly sharp drop in India fuel oil demand is anticipated (with an offsetting 2020 spike in gasoil), down by an average of 6.6% per annum, 2014-20, with additional downside pressure also being applied on industrial and power sector usage. Indian kerosene demand, meanwhile, is forecast to fall steadily in favour of natural gas and LPG, as Indian government policy seeks to phase out its use as a low-income cooking fuel. Drops in kerosene use will be too low to offset rising air travel demand for jet fuel, however, so that combined jet fuel/kerosene demand continues to edge up.

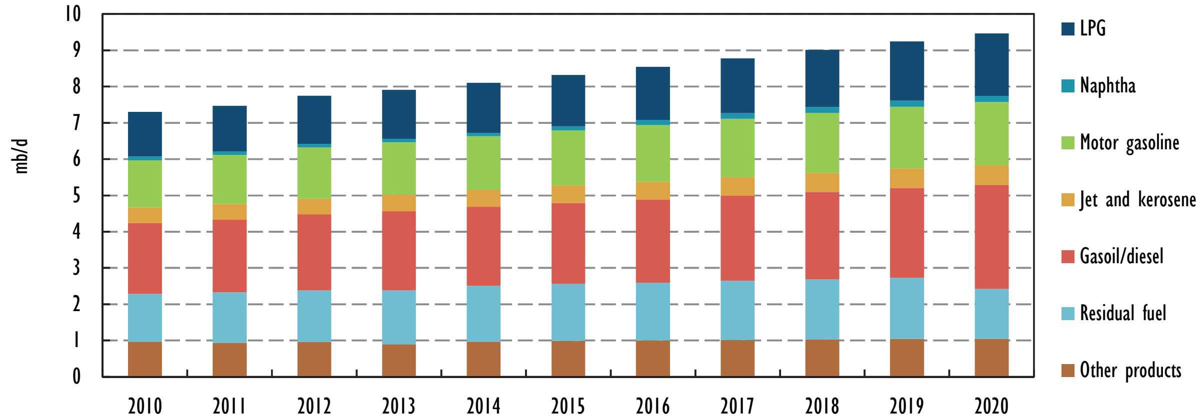
Although non-OECD Asia does not contain any large net oil exporting countries, the demand outlook for modest non-OECD net-exporters, such as Malaysia, has been marginally downgraded, with lower crude prices, 2H14-through-early 2015, denting prospective revenues from energy exports. It must be noted, however, that the negligible share of their net-exports in their overall economic weighting limits this downside. Starting at around 685 kb/d in 2014, for example, the Malaysian demand outlook is for an average per-annum gain of 3.1%, 2014-20, to approximately 820 kb/d in 2020.

Given the Middle East's role as one of the world's largest oil producing and exporting regions, the recent oil price plunge has curbed economic growth forecasts in the region. According to the IMF, Middle Eastern economic activity grew at around 4% per annum, 2007-13. But the IMF says this growth rate is unlikely to exceed 3% between 2014-16.

Even before these price-driven macroeconomic reductions were occurring, two key influences were acting as brakes on the composition of the Middle Eastern demand forecast. First, and despite the sometimes-heightened presence of domestic price subsidies in many countries, strong efficiency gains are forecast to run through 2020. Even without significant pricing pressures, average vehicle efficiencies are almost certain to improve as the vehicle market is a global one and price pressures elsewhere have encouraged rapid developments in average vehicle efficiencies. Secondly, geopolitical issues in many countries, such as Iraq and Syria, with 185 kb/d and 115 kb/d respectively trimmed from their 2019 demand forecasts, have acted as a deterrent to more robust macroeconomic and oil demand forecasts.

The big oil-exporting economies, such as Saudi Arabia, Iraq, Iran and Kuwait, lead the recent lower-price induced forecast downgrade. Growth projections for some other notable Middle Eastern countries, such as Yemen, have also been downgraded as their absolute forecasts remain below those carried last year on account of curbed baseline data. Not only have the latest annual estimates from the IEA's *Annual Energy Statistics of Non-OECD Countries* (commonly referred to as "Green Book") for Yemen, been revised down, at 130 kb/d in 2012 (140 kb/d before), but we have also in the *Oil Market Report* curbed the expected growth trajectory in 2015.

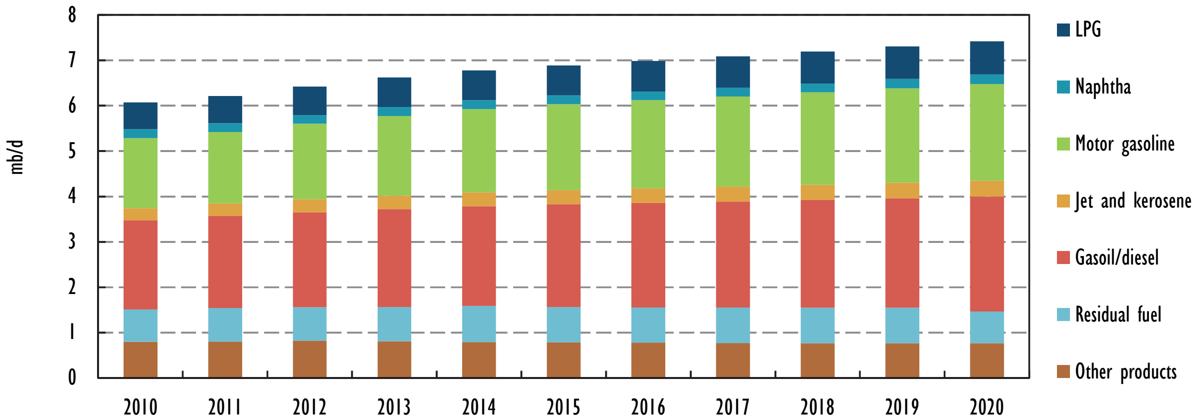
**Figure 1.8** Middle Eastern oil demand, 2010-20




The Middle East's dominant consumer (and producer), Saudi Arabia, is forecast to see a per annum gain of around 2.8%, 2014-20, a clear slowdown on the previous six-year trend (+5.7%) as deliberate efforts to encourage more efficient fuel use coincide with the downside contribution attributed to slower economic growth. The strongest gains are forecast in the gasoil/diesel and jet/kerosene sectors, as industrial and air-transport demand growth remain reasonably secure, while fuel oil lags on lower power demand. Stricter building standards raise insulation requirements, which will in turn curb growth in future air conditioning needs (which accounts for roughly 70% of Saudi Arabian residential electricity demand), diming power-sector energy usage. Riyadh has introduced tougher industry efficiency standards (for buildings, appliances, etc.), the enforcement of which deliver large savings in oil demand. For example, the Saudi Arabian Ministry of Commerce and Industry confiscated 50 000 air conditioners from stores that did not meet its energy saving requirements for 2014. Gasoline demand growth should also be restrained at around 3%, 2014-20, well down on the previous six-year trend as the government announced plans, late-November, to gradually phase-out older, less fuel efficient, vehicles with "a Saudi standard for fuel efficiency in light vehicles" to be implemented by 2016. For any further progress in slowing gasoline demand growth, however, serious efforts are going to have to be made to reduce subsidies, as at present domestic gasoline prices in Saudi Arabia are less than one-tenth European prices.

A relatively subdued Latin American demand forecast is also now being carried, with an average per annum gain of 1.5% foreseen, 2014-20, roughly half the previous trend, with notable slowdowns applied to Brazil, Venezuela, Colombia and Argentina. Curbed macroeconomic outlooks for these countries played a key role undermining the forecast growth trajectory, as did the now-reduced crude oil price outlook, as lower prices severely dampened the domestic wealth of net oil-exporting economies such as Venezuela. On Argentina, for example, the IMF's January 2015 *WEO* envisaged economic growth struggling to get back into positive growth territory before the end of the decade, a situation that is likely to have deteriorated further on the sharp 2H14 oil price declines. The struggling Argentinian economy will likely see basically flat domestic demand, 2014-20.

**Figure 1.9** Non-OECD Americas oil demand, 2010-20




A sub 2% per annum Brazilian oil demand expansion is foreseen, 2014-20, as the IMF, in January 2015, predicted GDP growth of 0.3% in 2015 accelerating to around 1.5% by 2016. Such a subdued macroeconomic backdrop curbs the oil demand forecast, albeit with modest support applied from lower oil prices as Brazil likely remains a net-oil importer. Up from an estimated 3.2 mb/d in 2014, Brazilian oil deliveries are forecast to rise by approximately 1.7% per annum, to 3.5 mb/d in 2020.

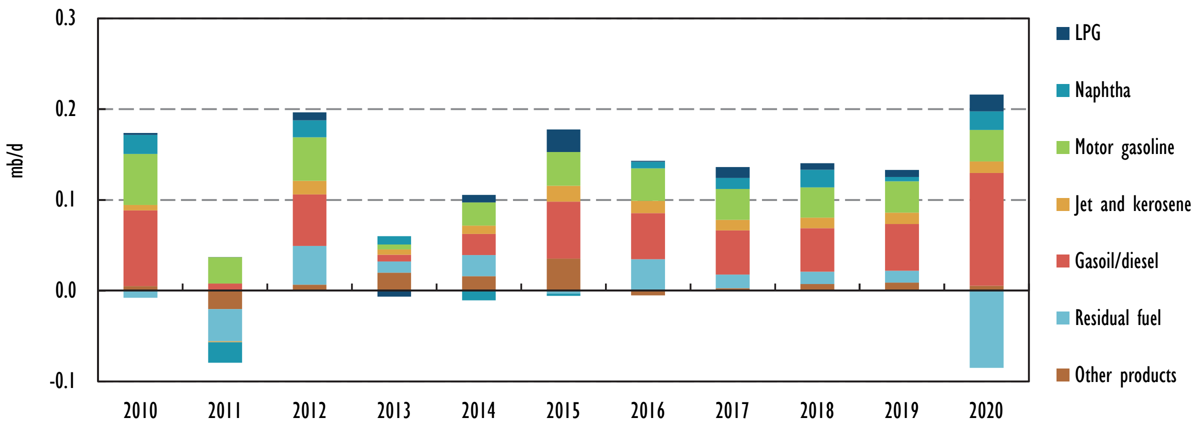
With crude oil prices far below the level at which the Venezuelan economy can realistically balance its finances, at least without a dramatic restructuring, Venezuelan oil demand is unlikely to break through 0.8 mb/d by 2020. With expectations for the health of the Venezuelan economy having deteriorated sharply since the publication of last year's *Report*, nearly two whole percentage points have been trimmed from the forecast per annum growth rate, to -0.6% 2014-20. On a related issue, lower oil revenues in Venezuela will dampen the spending power of Petrocaribe, reducing the availability of subsidised energy products in Antigua and Barbuda, the Bahamas, Belize, Cuba, Dominica, Dominican Republic, Grenada, Guyana, Jamaica, St Lucia, St Kitts and Nevis, Saint Vincent and the Grenadines, Haiti, Nicaragua, Honduras and Suriname, thus denting their demand outlooks as well.

Other net oil-exporters, such as Ecuador and Trinidad and Tobago, were downgraded marginally on the year earlier forecast, as lower oil prices feed into their now curtailed macroeconomic environment. In Trinidad and Tobago, total oil product demand is forecast to rise from around 45 kb/d in 2014 to 50 kb/d in 2020.

Despite recent macroeconomic wobbles and lower oil prices denting prospective revenue flows in net oil exporting economies, Africa remains one of the brightest potential oil demand growth prospects through to the end of the decade. This is partly because of the very low per capita consumption levels that currently exist, but also has to do with projections of strongly expanding vehicle numbers and the relatively subdued levels of prospective efficiency gains. Starting at approximately 3.9 mb/d in 2014, the total African oil demand forecast rises to an estimated 4.8 mb/d by 2020, equivalent to an average per annum gain of 3.3%, likely resulting in a net-inflow of refined products.

The recent declines in oil prices, 2Q14-4Q14, have resulted in two clearly contrasting revisionist tendencies across the African continent. Firstly, a notable downgrading in the demand outlook of net-oil exporting economies now exists; secondly, the demand outlook for net-oil-importers has been raised. Net-oil-exporting African nations, such as Angola, Algeria and Nigeria, hence face lower potential future national income streams, as curbed oil-export revenues are likely to dampen pending government expenditures and, hence with all else being held equal, GDP. This accordingly curbs prospective oil demand in net oil-exporting economies. The demand benefits in net oil-importers very much depends upon the degree to which lower prices are passed on.

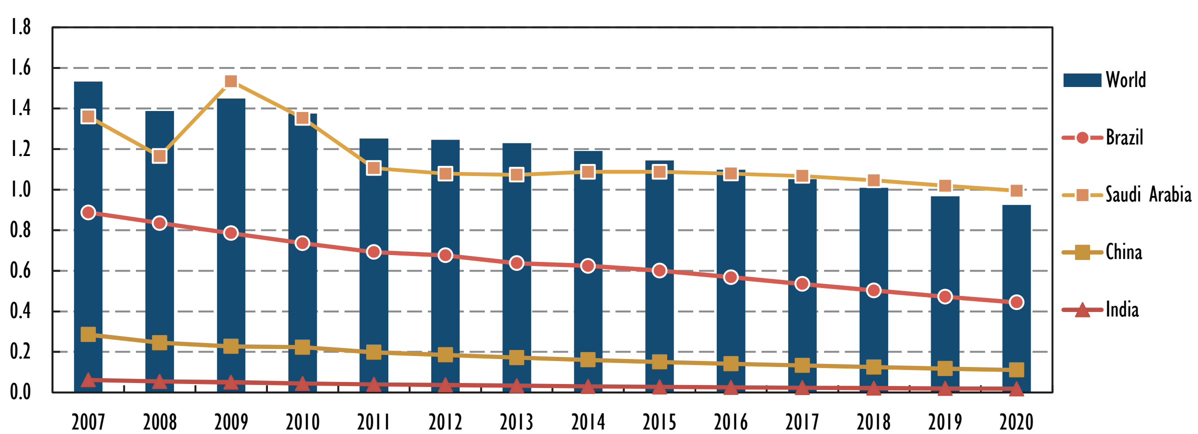
**Figure 1.10** Africa oil demand growth, 2010-20




## *Sea change in retail pricing*

The desire to reduce costly energy-price subsidies has been around for a while, but the mid-2014 crude oil price collapse provides a large additional stimulus to policy makers as far as instigating an uptick in non-OECD energy price de-subsidisation. Recent months have seen many cash-strapped net oil-exporting non-OECD economies adopt the de-subsidising mantle, an action initially taken up by large net oil-importer India. Recent months have seen many non-OECD oil producers, such as Indonesia, Kuwait, Malaysia and Egypt, announce further de-subsidisation steps. This non-OECD progress reduces/overrides the potentially supportive demand-side influence otherwise provided by lower crude prices. A number of other, generally oil consuming, non-OECD nations also announced energy subsidy cuts in 2014, including Thailand and Morocco.

**Figure 1.11** Non-OECD oil intensities projected to decline




Lower retail price subsidies mean that, with all else being held equal, consumer product prices will be higher, dampening oil product demand. Additionally, imposition of additional consumption taxes, such as China implemented in both November and December, further reduce, ceteris paribus, impending demand.

This de-subsidisation/higher taxation trend means that non-OECD oil consumers, indeed consumers in general, do not see the price declines that they would have otherwise, coinciding with lower demand trends. Of course, the potential to cut subsidies is limited, curbing the extent of this downside impact on demand towards the end of the sample. In contrast, the potential to raise consumption taxes is much higher, although politically problematic. A forecast continuation of the recent downside pressure on subsidies trims the non-OECD demand forecast to an average per annum gain of 2.4%, 2014-20.

## *Communication goes virtual rather than physical*

The IT revolution lets emerging markets, to some degree, bypass forms of infrastructural development, with the 'normal' or OECD path of oil development no longer deemed necessary, or required, as technological developments allow non-OECD nations to by-pass some of the changes in the demand-mix. The widespread adoption of better communication channels deems many of the previous physical journeys to no longer be necessary, as modern communication platforms make many more forms of communication electronic. On the flip-side, e-commerce leads to additional demand possibilities as IT provides access to business and consumption possibilities that would have otherwise been closed.

The growing importance of electricity in the demand mix for a developing nation also impacts upon oil product demand from another secondary direction, as the power-sector has increasingly in recent years become a less relevant component of the total oil demand picture. Back at the turn of the century, roughly one in every fourteen barrels of oil consumed was in the power sector; by 2012, this ratio had fallen to just shy of one in 17 barrels, today it is likely to be even less.

## *Fuel switch and efficiency*

The demand forecast has been curbed by the political drive to cut emissions and eradicate wasteful oil consumption, two pressures that are particularly pronounced in the newly evolving non-OECD. These changes are very real, with non-OECD governments following some extremely ambitious policies and aggressively deploying them in some of the economies that until recently had experienced some of the fastest demand growth rates; for example, China and Saudi Arabia.

### **Box 1.1** Impending efficiency gains to curb prospective oil demand

Years of high oil prices coupled with tightening environmental standards have stimulated a culture of steep efficiency gains; this momentum is forecast to keep global oil demand growth on a relatively flat trajectory. Given the macroeconomic numbers that underpin the oil demand forecast, an average global efficiency gain of around 4% per annum keeps oil demand growth pinned back in the 1.2% per annum range.

History has, almost without fail, demonstrated that over time less oil is required to produce an almost identical product or service, or more broadly the same level of economic activity. Efficiency gains drive this momentum, as vehicles and machines have historically improved their efficiencies over time. One method for measuring efficiency is to track changes in the oil intensity, i.e. variations over time in the amount of oil that is required to produce a certain level of economic output. In 2014, for example, the global oil intensity was estimated at 1.19, equivalent to estimated global oil product demand (92.4 mb/d) divided by the real global GDP assessment (USD 77.6 trillion). Comparing this to 2013, when it was 1.23, crudely equates to a decline of 3%, or an efficiency gain of 3% in global oil use.

This forecast assumes an uptick in the impending pace of efficiency growth, as a number of previously heavily subsidised consumers gradually adjust their pricing mechanisms (for example, India, Indonesia, China, Kuwait, Thailand, Egypt, Malaysia, etc.), while others (such as Russia and Venezuela) are forced, by economic necessity, to dramatically curb their oil use.

**Box 1.1** Impending efficiency gains to curb prospective oil demand (continued)

Additionally, significant structural changes in the Chinese economy, coupled with product switching out of oil, further curb the global oil intensity, by default increasing this simplified efficiency gain projection.

**Table 1.5** Global oil intensities

| | 2008 | 2014 | 2020 |
|---|---|---|---|
| **Global oil intensity** | 1.39 | 1.19 | 0.93 |
| **Oil demand, mb/d** | 86.5 | 92.4 | 99.1 |
| **GDP, USD trillion** | 62.3 | 77.6 | 107.1 |

Sources: IEA analysis; IMF.

Despite steep efficiency gains being available in the transport, industry, residential agriculture and commerce sectors of the economy, transport likely makes the dominant contribution to the projected pace of global efficiency growth, as transport accounts for around 55% of total global oil deliveries. Years of relatively high prices in the United States encouraged a wave of more efficient vehicle purchases, which were then brought into the legislature through tighter CAFE standards. First enacted roughly 40 years ago, in the wake of the steep oil price ascents of the 1970s, CAFE standards have steadily legislated for a more fuel-efficient vehicle fleet in the United States. In 2015, for example, the CAFE standard in the United States is 39 miles per gallon (MPG) for a 41 square foot (SQ) or smaller passenger car, falling to 30 MPG for a vehicle smaller than 55 square feet but larger than 41; through 2020 the respective CAFE standards rise to 49 MPG and 36 MPG, very broadly equivalent to average vehicle efficiency gains of between 4% and 5% per annum.

The majority of other OECD economies have much higher levels of consumption taxes than the United States, the presence of which add to the incentive to purchase more efficient cars, as do the existence of annual ownership duties which often go up along with emissions, which are normally negatively linked to engine efficiencies. Even without such taxes/regulations, the general trend is towards more fuel efficient vehicle choices, as engine technologies have made great steps forward recently and worsening traffic/parking problems have made smaller vehicle choices more popular, which by default tend to be more efficient. The United States provided, at the end of 2014 into early-2015, what we believe to be a temporary break from this trend, as sales of four-wheel drive vehicles rebounded.

Strong non-OECD efficiency gains are also forecast, with the technological developments that have been made in engine technology likely fuelling a heady pace of non-OECD efficiency growth. We particularly focus attention on China, as additional efficiency gains there are an essential determinant underlying the recent slowdown in global oil demand growth and will likely curb demand momentum moving forwards. The government has made it increasingly clear in recent years that it intends to tackle both its air pollution problems and curb its energy import bill, with energy efficiency one of the key goals of the 12th Five-Year Plan (5YP), 2011-15. Specifically a target of a 16% reduction in the overall energy intensity was set by the 5YP, an objective we foresee being achieved for oil.

**Table 1.6** Chinese oil intensity, IEA forecasts

| | 2008 | 2014 | 2020 |
|---|---|---|---|
| **Total oil intensity** | 0.66 | 0.54 | 0.43 |
| Industry | 0.09 | 0.07 | 0.05 |
| Transport | 0.28 | 0.25 | 0.21 |
| Petrochemicals | 0.06 | 0.06 | 0.05 |

**Box 1.1** Impending efficiency gains to curb prospective oil demand (continued)

Based upon data from the IEA's *Annual Statistical Supplement* and the *Oil Market Report*, we show an average per annum efficiency gain of roughly 3% in China, 2009-14, led by the energy-intensive industrial sector, which posted an average per annum efficiency gain of approximately 4%. Strong efficiency contributions were also seen in the transport, petrochemical, residential and agricultural and fishing industries. Once again, one cannot draw too many conclusions from just a couple of years' worth of data, but both 2013 and 2014 showed notable increases in Chinese efficiencies, going a long way towards explaining the sharp slowdown that has occurred in Chinese oil demand growth in recent years.

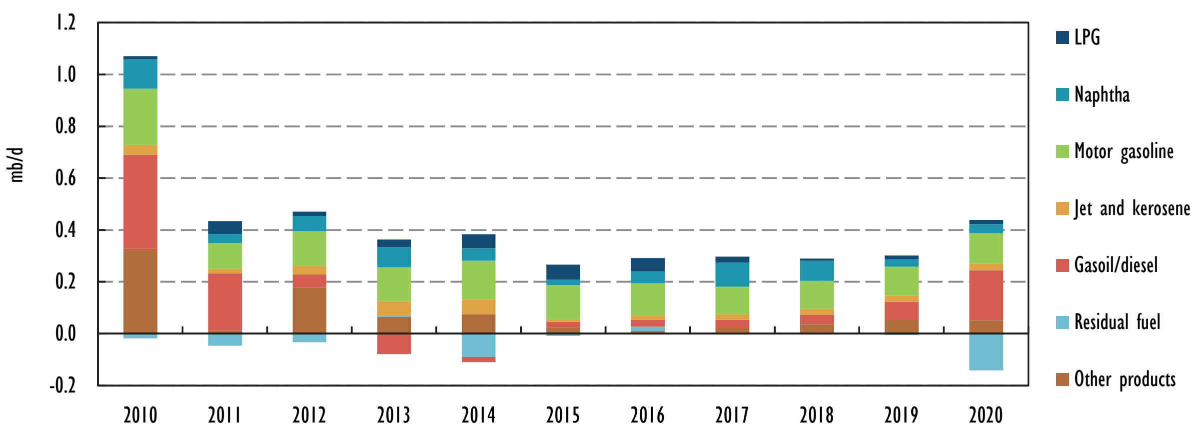
A continuation, albeit a moderation, of these trends supports the relatively subdued Chinese oil demand forecasts in this *Report*. Increasingly efficient oil use, when coupled with a likely easing in the macroeconomic backdrop and further product switching, will see an average per annum demand gain of 2.6% 2014-20. Through the forecast period, the industrial, commerce, agricultural and transport sectors will lead the strong collective Chinese efficiency drive.

Higher efficiencies alone, of course, do not necessarily dampen global oil demand trends, as rising global populations continue to put a much more supportive spin on the total demand numbers, while increased wealth in many vast population centres, such as China, India, Indonesia, Bangladesh, etc., also stimulate additional oil demand. Rather than causing absolute demand declines in any major demand centres outside the OECD, escalating efficiency levels act to slow the pace at which oil demand likely expands.

## *China shifts gears*

The structural make-up of the Chinese economy is rapidly evolving, from its traditional high-investment/manufacturing/export-driven configuration, increasingly over to a more domestically focussed structure. As this shift occurs, the Chinese economy becomes increasingly focussed on more efficient oil use, lower pollution and sustainable growth. As already outlined in detail, in *Impending efficiency gains to curb prospective oil demand*, the strong Chinese efficiency gains posted in recent years have gone a long way towards explaining the recent transformation that has occurred in Chinese oil demand growth. President Xi Jinping's "new normal" encompasses curbed oil demand growth as the closure of excess capacity in many industries, most notably coal and steel, filters through to lessened oil demand growth. These heady efficiency gains, coupled with deliberate government efforts to curb energy demand, in order to satisfy tightening clean-air regulations, and the recent easing in macroeconomic conditions, explain the definite *shifting in gears* that has been seen in China.

**Figure 1.12** Chinese oil demand growth, 2010-20



The Chinese demand forecast is for a relatively modest 2.6% per annum growth rate, 2014-20, taking total Chinese oil use up to an average of around 12.1 mb/d by 2020. The greatest upside momentum during the outlook period is forecast to occur in the transport markets, as the gasoline and jet fuel sub-markets remain best protected from the potential product switches that have heavily dampened gasoil/diesel and residual fuel oil in recent years. The average efficiency gain that is forecast to hold, 2015-20, of 3.7% per annum, exactly matches that seen 2008-14.

Having risen by approximately 0.5 mb/d per annum in the ten-year period, 2003-12, the near-halving in momentum that has ensued is one of the key changes that has driven the global slowdown in oil demand growth these past couple of years. Previously two out of every five barrels of global oil demand growth was attributable to China, but the dramatic deceleration that followed weakened the hand of this key support, stripping back the global growth trend below 1 mb/d in 2014. Clearly a weakening in the still-robust Chinese macroeconomic growth trend played a key role, but it was not alone as product switching, additional efficiency gains and efforts to clean up worrisome Chinese air pollution levels all contributed. The IMF's January 2015 WEO estimated that the Chinese economy would expand by 6.8% in 2015, six-tenths of a percentage points below the 7.4% gain seen in 2014 and sharply lower than the near-double digit annual percentage point growth regularly seen at the beginning of the decade. Macroeconomic momentum in China is forecast to then ease further still, down to around 6% through to remainder of the medium-term forecast, additionally pressurising oil demand growth in an economy increasingly less focussed on industry/manufacturing/exports.

Starting from 2003, as it was the year that the previously rampant Chinese oil demand trend really started to pick-up momentum, the oil intensity stood at 0.82: i.e. for every Yuan 1 billion of gross domestic product created, 0.82 kb/d of oil products were required. The Chinese oil intensity rose, to 0.86, in 2004 as the Chinese economy increasingly moved into heavier, more oil-intensive industries and forms of manufacturing, before steadily trending south, to around 0.54 by 2014. A further decline, to around 0.43, is foreseen towards the end of the decade.

Within the Chinese economy, the petrochemical, transport and industrial sub-sectors are forecast to be amongst the sharpest declining oil intensities through to the end of the decade. Transport, as sales of increasingly more fuel efficient engine technologies improve the overall fuel efficiency of vehicles on Chinese roads; petrochemical, as heavy investments in newer plants resulted in a much less feedstock intensive industry; and industry, as plant and machinery become increasingly more energy efficient. It was these efficiency gains, which along with periods of weaker Chinese economic growth, tightening pollution controls and product switching, that triggered the sharp recent curtailments in Chinese oil demand growth.

The accumulated impact from more efficient Chinese vehicle purchases has led the sharp declines that have been seen in the oil intensity of the Chinese transport sector. For example, back in 2000 the average fuel efficiency of a newly sold passenger light duty vehicle (PLDV) in China was 8.2 litres of gasoline per 100 kilometres (km). By 2005 it had fallen to 7.7 litres/100 km, equivalent to an average efficiency gain of roughly 1.2% per annum, with the IEA's *EDT* unit forecasting a fall to 7.0 litres/100 km by 2015 and 6.5 litres/100 km by 2020. The eventual outcome could be even lower if the State Council's 5.0 litres/100 km 2020 target is achieved, although there are doubts about the 2020 feasibility.

In recent years, the key downside contributor to the overall slower Chinese demand story has been gasoil/diesel, with absolute declines seen in both 2013 and 2014. Having previously risen by an average of around 8% per annum, 2003-12, respective drops of 2.3% and 0.6% were seen in 2013 and 2014. Weakening economic growth, chiefly from industry, is often highlighted as a key reason for the reversal, but in reality the published economic numbers, although they do show a deceleration in momentum, have not changed sufficiently to justify the scale of the absolute demand declines seen. Of course these economic numbers may be more fable than reality, but regardless we still think more answers are required on this conundrum.

Another more-likely culprit for declining Chinese diesel demand is that efforts to clean up heavily polluted Chinese cities have brought about more stringent environmental regulations on industries, such as those that heavily burn coal. These additional efforts have accordingly curbed the amount of diesel that was then required, tapering trucking/rail needs, an important sub-sector of diesel demand that we cannot emphasise enough. Vast quantities of coal have traditionally been transported between Northern China and the east coast, contributing heavily to the oft-double digit percentage point gains that were seen in Chinese diesel demand the mid-2000s.

Consolidation in many previously rapidly expanding industries, notably the huge steel, cement and construction sectors, not only dampen diesel demand forecasts through their impact on the amount of coal that needs to be transported but also through the now curbed general industrial requirement. The Ministry of Industry and Information Technology, for example, issued an edict (May 2014) calling for capacity cuts of approximately 4% in steel, 2% in cement, 2% in coking coal and 5% in iron in 2014, a trend that is likely to require further consolidation in order to meet the government objectives.

Similarly, China's definite tendency to be an early-adopter of gas-powered transportation technology has also curbed China's gasoil/diesel needs. This increased use of natural gas powered vehicles (NGV) has played a key role in the recent weakening in Chinese gasoil/diesel demand. NGV sales came in at approximately 0.5 million in 2014, taking the total Chinese NGV fleet to over 1.5 million, which alongside escalating efficiency gains in the total Chinese vehicle stock, curbed movements of coal and the weakening macroeconomic backdrop severely dampened Chinese oil product demand. The Chinese authorities have an ambitious target of 5 million NGVs by 2015. Tracking forward, Chinese gasoil demand is forecast to see only a very weak, sub 2% per annum trend through to the end of the decade, an event that is somewhat inflated by the additional bunker fuel demand that is forecast to arrive in 2020 when global shipping sulphur regulations are tightened. The gasoline demand forecast, of a +4.7% per annum gain 2014-20, is similarly curbed on additional NGVs, but to a lesser degree it is mainly the largely diesel-powered bus, courier and taxi services that are forecast to switch.

Risks surround the forecast of further Chinese movements into NGVs, both to the upside and downside. In our base-case scenario, the projected ratio of road transport demand accounted for by NGVs roughly doubles between 2013 and 2020, rising into double-digit percentage terms by the end of the decade. Further indents into conventional fuelled transport markets would accordingly curb both the gasoline and gasoil/diesel demand forecasts, and vice versa.

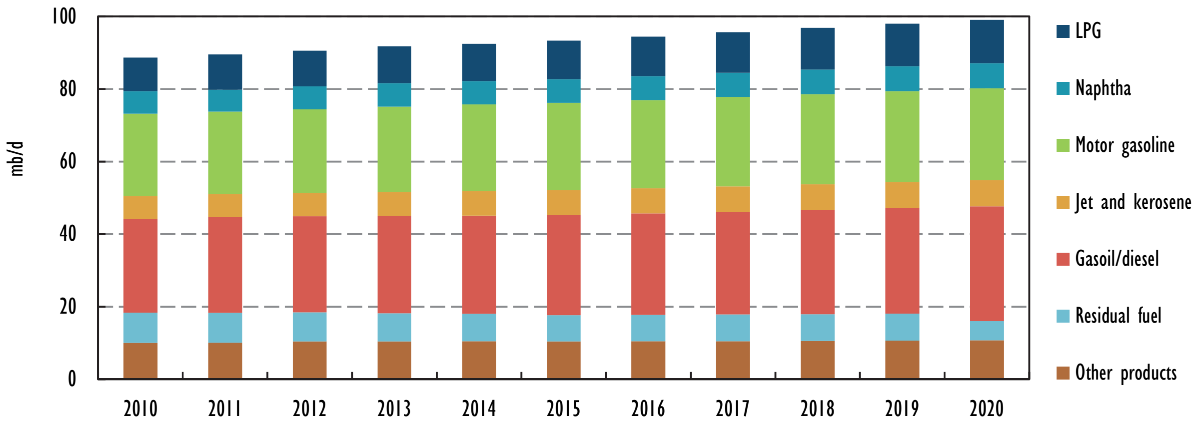
Looking at the latest detailed Chinese demand data from the IEA's *Annual Energy Statistics of Non-OECD Countries 2014* it is apparent that the gasoil intensity, i.e. the amount of gasoil that is used as a ratio of economic activity, is highest in the automotive sector. Efficiency gains in this sector, along with the commercial/agricultural and industrial sectors, provided further impetus for Chinese diesel demand to fall, 2013-14. Having posted an average annual efficiency gains approaching 7% per annum, 2008-12, the lessening diesel requirement from industrial sector then likely plays a key role restraining future Chinese gasoil demand growth.

Assuming the economic figures on China are correct, with the average economic growth rate down by around two-fifths since the turn of the decade, it is hard to see any more than 0.3 mb/d of Chinese oil demand growth any year through 2020.

## The changing demand barrel

The make-up of the demand barrel changes over time, as varying contributory factors such as changing environmental regulations alter the demand for specific products and hence their prices, redirecting the pressure to the downstream.

**Figure 1.13** Global oil demand growth, 2010-20




### **Box 1.2** Detailed look at jet fuel

Global jet/kerosene demand is forecast to grow by approximately 1.1% per annum to 7.2 mb/d in 2020 from 6.8 mb/d in 2014, making it the third fastest growing petroleum product after LPG (including ethane) and gasoil/diesel. Unlike LPG, where ample supplies contribute to the growth, and gasoil, which is forecast to take significant market share from residual fuel oil as a marine bunker fuel due to legislation, projected jet/kerosene growth comes mainly from traditional macroeconomic gains.

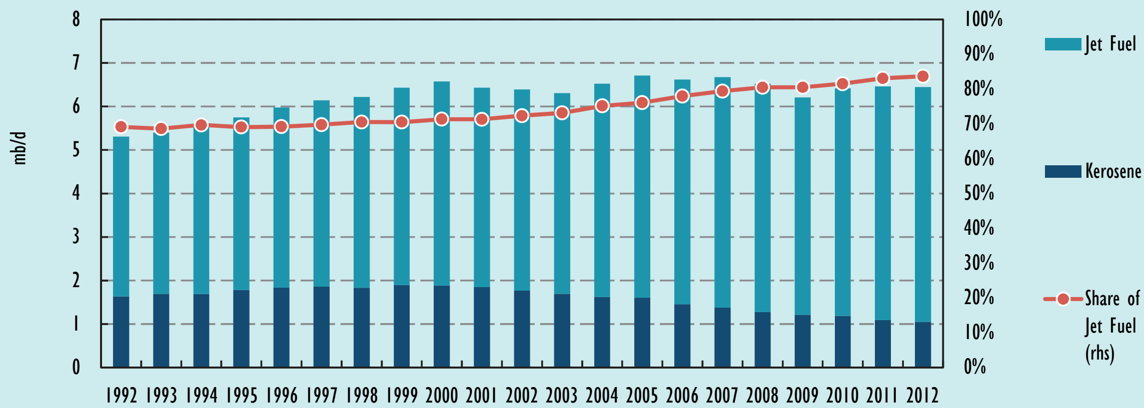
Around 85% of jet fuel/kerosene demand in 2014 was jet fuel, with kerosene used for space heating (predominantly in Japan) accounting for the residue. Heating kerosene demand has been steadily declining since 2000; the aviation sector accounting for all future growth in jet/kerosene demand. Rising air-transport demand in developing countries drives this trend, with forecast momentum only really kept under relative wraps by efficiency gains.

Whereas emerging economies have already overtaken the OECD in total oil use, such is not the case for transport fuels such as gasoline and jet fuel, demand for which remains largely OECD-centred. Non-OECD economies are catching up fast, with non-OECD jet/kerosene demand forecast to grow by 2.6% per annum 2014-20 and to contract by 0.1% in the OECD. The faster non-OECD forecast reflecting rising incomes and growing domestic demand for air travel, but that is not the whole story. Non-OECD economies are also emerging as international airline hubs in their own right, with Dubai recently overtaking London Heathrow as the world's busiest airport. As recently as 2005, the only non-OECD location among the world's 15 busiest airports was Beijing. By September 2014, the top 15 airports, beside Dubai, also included Hong Kong, China; Istanbul; Jakarta and Guangzhou. This trend is forecast to continue, with China, Africa and Middle East leading the growth.

**Box 1.2** Detailed look at jet fuel (continued)

Changing technological and fleet management techniques act to trim the potential pace of jet/kerosene demand growth, significantly below that which would have otherwise ensued given the mid-3% pace of economic growth that forecasters such as the IMF predicted in January 2015. Both of world's top aircraft manufacturers, Boeing and Airbus for example, have produced more fuel-efficient flagship models, the 737 and A320 respectively, set to reduce consumption by around 20% over previous models. The first commercial deliveries of the new A320 takes place in 2015 and two years later Boeing will deliver the new 737. Slow aircraft turnover rates essentially draw these efficiency gains through the medium-term forecast. The International Air Transport Association (IATA) estimates the fleet replacement's contribution to fuel efficiency at 1.5% per annum, but the dark economic climate may rush the process.

**Figure 1.14** Global jet/kerosene demand, 1992-12




Management systems/structural improvements across the airline industry, particularly load factors, helped the industry recover in the post-recessionary world. Better management systems increased passenger load factors, from 73% in 2004 to 79% in 2013. The weight load factor, defined as the ratio of the actual plane weight to the maximal takeoff weight, remained significantly lower at 61% and 67%, respectively. Under the most common ticketing system, it is difficult to predict the actual plane weight as the lump sum for baggage weight and a statistical average for passenger weight provide a very wide proxy. Further boosting the weight load factor would require further changes, also on a legislative level. In 2013, the US Department of Transportation for example, allowed Samoa Airlines to charge passengers according to their weight (with luggage) on international flights to American Samoa. Such pricing schemes remain controversial but have the potential to improve air transport efficiencies.

Future technologies play an important role in the changing make-up of jet/kerosene demand, with IATA, in its *Technology Roadmap*, discussing many different ways to curb use. Starting from better plane aerodynamics to advanced engine technologies; retrofitting of old planes to developing new windowless and hybrid-wing-body planes. Many of the improvements focus on decreasing plane weight, some in sophisticated ways like flying without land gear and others in trivial ways like minimising in-flight magazines. Both incremental changes and breakthrough approaches are equally important for airline and plane manufacturers. IATA, in their *Airline Industry Forecast* 2013-17 reported airline passenger numbers rising by 31% whereas, in the same time frame the IEA reported a much more muted increase in jet fuel demand of just over 8%, a gap largely attributable to efficiency gains.

**Box 1.2** Detailed look at jet fuel (continued)

The majority of projected jet/kerosene demand growth is forecast for non-OECD Asia, with this still rapidly expanding region contributing roughly two-thirds of global growth, China accounting for nearly a half of this. Relatively strong gains are foreseen in Africa and the Middle East, respectively accounting for 17% and 16% of global growth, 2014-20. Absolute declines are forecast in the OECD, however, as the market has been saturated to a point that efficiency gains and the evolution of airline transport hubs, out of the OECD increasingly towards non-OECD countries, offsets the otherwise supportive industry growth.

**Figure 1.15** The improving efficiency of air transportation, 2004-12

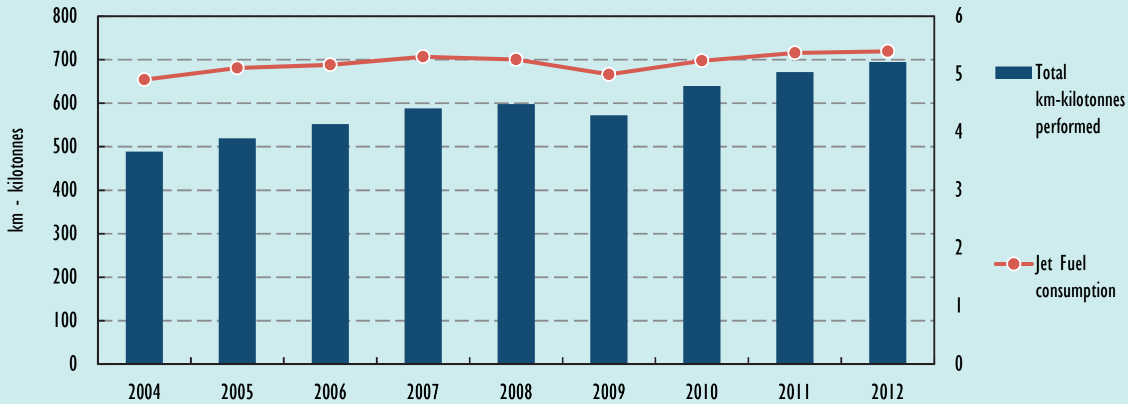
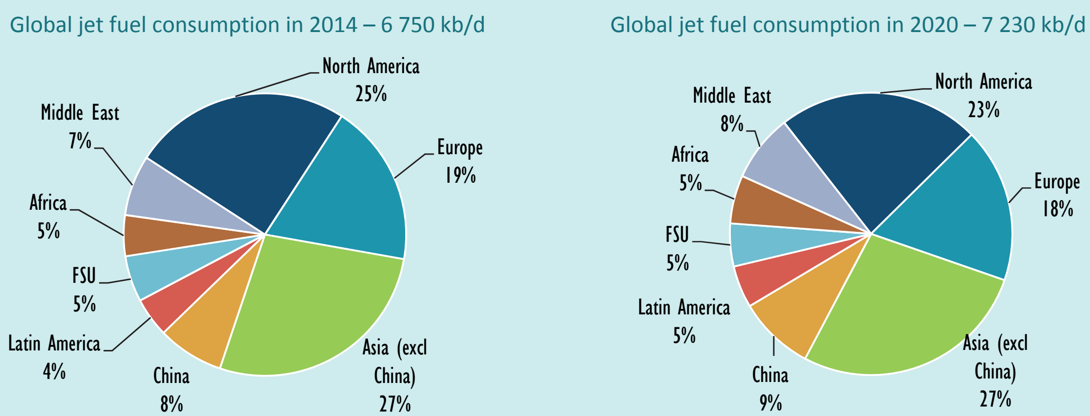



**Figure 1.16** Global jet/kerosene demand by region



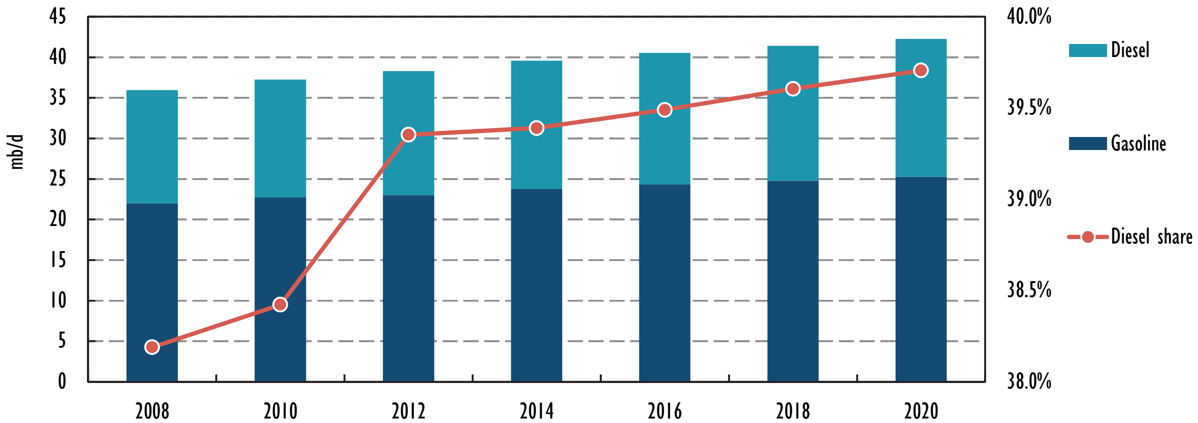

## *Slowing pace of dieselisation*

Recent years have seen the previously voracious pace of diesel demand growth ease back somewhat, as two portentous pillars that underpinned erstwhile strong diesel demand growth, i.e. China and India, saw their contributions abate. Although the sharp slowdowns in India/China of 2013-14 are not expected to have been made permanent, the heady pre-slowdown gains are unlikely to be reclaimed anytime soon, at least for China, keeping diesel's share of the global road oil transport fuel demand on only a gently expanding trajectory. Escalating concerns regarding the inhalation of unfiltered diesel particulates further constrain the forecast pace of dieselisation, 2014-20. Particularly acute pollution problems in many European cities in the spring of 2014 were largely blamed upon diesel particulates. Although new diesel engines with the correct filtration systems fitted abate the problem, political pressure to equalise the tax treatment on gasoline and diesel (most European countries apply higher levels of taxation on gasoline), would negatively impact diesel.

Prior to 2013, Indian gasoil demand growth had rumbled along at a robust five-year average of around 7%, 2008-12, but strenuous efforts to reduced subsidies saw this trend broken. Indian gasoil/diesel demand growth all but disappeared, 2013-14, essentially removing around 0.1 mb/d from global diesel demand in 2013 and if you consider the missed accumulation of momentum, removed approximately 0.2 mb/d from 2014. Although relatively robust Indian diesel demand growth is expected to return, with an average per annum gain of nearly 5% 2015-20, the aggregate impact of diesel subsidy cuts should support Indian gasoline demand versus diesel.

Structural changes in China (see *China shifts gears*) saw an about turn of approximately 230 kb/d in gasoil/diesel demand growth, as China went from a five-year average gain of approximately 180 kb/d, 2008-12, to an average decline of 50 kb/d, 2013-14. Although modest Chinese diesel demand growth is expected to return, post-2015, the structural changes already outlined should ensure the heady heights experienced earlier in the century do not return.

**Figure 1.17** Global road oil demand, 2008-20




These two countries alone, comparing their five-year average gains in 2008-12, to the sharp diesel slowdown of 2013-14, approximately 0.3 mb/d of demand growth has been lost (0.6 mb/d if the comparison is made accumulative). Although diesel demand growth is expected to pick-up, post-2014, the global dieselisation is only forecast to increase gently, 2015-20, as escalating health concerns regarding unfiltered diesel particulates put upside pressure on European tax structures, with currently generally support diesel at the expense of gasoline.

## *Changes in marine transportation and the distillate outlook*

Two of the biggest forecast changes surround marine fuels, as tighter emission regulations likely trigger some switching out of residual fuel oil (see *Sea change in bunker fuels*). Initially a tightening in North American, North Sea and Baltic Sea sulphur legislations leads to an estimated 0.2 mb/d switch from heavier-sulphur fuel oil bunkers to marine diesel, in 2015. Then in 2020, assuming the global tightening in sulphur regulations passes into law, up to a further 2.4 mb/d of residual fuel oil demand is forecast to be lost, with marine gasoil accounting for the majority of the replacement demand (up to 2.2 mb/d) along with small gains in LNG powered ships (+0.2 mb/d).

# 2. SUPPLY

## Summary


- **Oil's decline in price of over 50% since June is putting the brakes on supply, with both OPEC and non-OPEC producers scaling back investment.** The net result is a slowdown in global oil capacity growth to an annual 860 kb/d over the forecast period compared to robust growth of 1.8 mb/d in 2014, which was led by non-OPEC. The world's total oil capacity by the end of the decade is expected to rise to 103.2 mb/d.

- **Price effects on supply differ from previous down cycles in two important ways**: OPEC has, for now, given up price support in favour of market share, with expectations of OPEC behaviour fundamentally reset. US light tight oil (LTO), far more dependent on short-term financing of day-to-day operations, is more price responsive and with its short lead times, could provide a fast supply response once terms look favourable.

- **The United States remains the top source of growth through 2020, increasing by 2.2 mb/d,** with most of the expansion from LTO – the most elastic source of supply in a low price environment. Much LTO output is profitable at current prices around USD 50/bbl, but marginal acreage and newer shale plays will see cuts. By early 2015, North American capital expenditures had been cut by more than 25% and additional reductions are expected.

- **Canada will expand by 810 kb/d through the forecast period to just under 5 mb/d, but low oil prices are hitting its main sources for growth - oil sands projects**. Offshore projects, too, will see delays and cancellations. In contrast to US LTO, Canada's output mainstays are projects with long payback periods.

- **In Iraq, the drop in oil prices and worsening security situation after the advance of ISIL militants in June 2014 pose daunting challenges, but have yet to cause a substantial slowdown in growth.** OPEC's second biggest producer is projected to increase capacity by 1.1 mb/d by 2020, which accounts for nearly 90% of OPEC's total build up in capacity over the next six years.

- **Russian output capacity contracts by about 560 kb/d up to 2020 due to the crushing impact of lower oil prices and Western sanctions that compound their effect.** Low oil prices will hit investment in Russia's greenfield development, desperately needed to offset brownfield declines, and also cut into funds that should be invested in field redevelopment and maintenance. This projection is further supported by a lower outlook on tight oil production.

- **OPEC crude capacity is expected to rise to 36.2 mb/d in 2020, with annual average growth limited to 200 kb/d.** Gains, dominated by Iraq, will be at risk given the political instability in the country. Oil's collapse has dimmed the outlook in Venezuela, Nigeria and Angola. The "call on OPEC and stock change" is forecast to start rising in 2016, reaching 32.1 mb/d by 2020 – or 2.7 mb/d above the call in 2014 – as cuts in spending take a toll on non-OPEC growth.

- **Non-OPEC oil supply is expected to grow by 3.4 mb/d to 60 mb/d in 2020, at an annual average of 570 kb/d.** This is significantly lower than growth of 1 mb/d over the last five years and record

growth of 1.9 mb/d in 2014. The declining growth in non-OPEC stems from lower capex in new projects and existing fields, which will see accelerated decline rates in Russia and the North Sea, among others.

- **Oil supply disruptions remain the wildcard. Political turmoil and security issues in key producer countries pose considerable risks.** The threat from Islamist militancy is clouding the outlook in Iraq, Syria, Libya, Nigeria, Yemen and possibly beyond. There is also a risk to social and economic stability resulting from prices that have collapsed far below the fiscal breakeven in countries such as Russia and Venezuela.

**Figure 2.1** World oil supply capacity growth

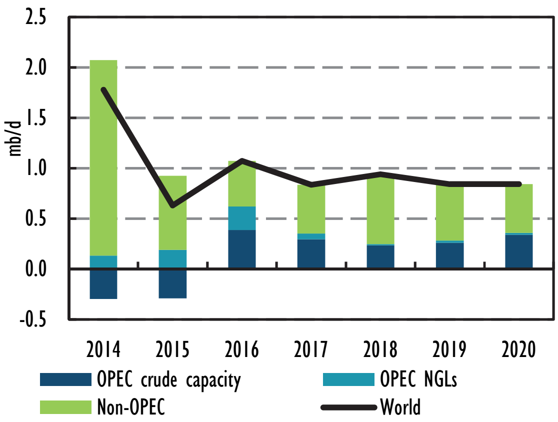
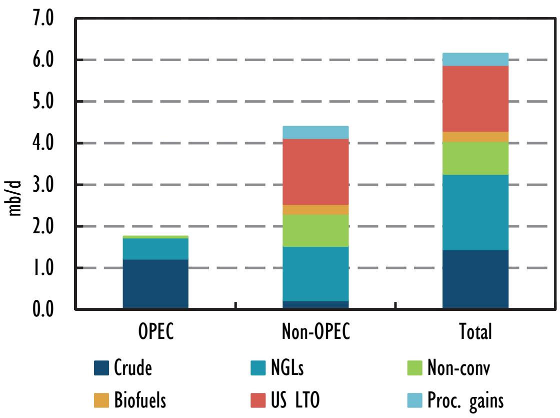



**Figure 2.2** Global liquids growth 2014-20




## A new chapter in oil supply

The next six years will be profoundly different from the preceding ones, not only as regards the pace of supply growth, but also in terms of the dynamics of upstream investment and production. A plunge in oil prices of more than 50% from their June 2014 highs has shattered expectations that the oil market had permanently entered an age of sustainably elevated prices – an assumption seemingly as vital to some high-cost megaprojects as to the budget requirements of many producer countries. The price collapse has done more, however, than force companies and producer countries to take an axe to their spending, and the industry to revisit project economics in a hurry. On a deeper level, it challenges industry participants to recognise the rules of the oil market have changed. The clear distribution of roles between OPEC and non-OPEC countries that governed the oil market for the last 30 years has been suspended, at least for now. Non-OPEC producers cannot, for now, count on OPEC to act as swing supplier and cut output in the event of a price drop. OPEC cannot be confident that non-OPEC supply is maxed out and incapable of being scaled up quickly.

These twin watershed events – the shattering of earlier price assumptions now exposed as exaggerated, and the breakdown of the traditional division of labour between OPEC and non-OPEC – change the supply outlook for the next six years in at least two key ways. First, they significantly reduce expectations of supply growth. Barring any new major output disruption within OPEC itself over the forecast period, lower prices are expected to cut non-OPEC oil supply growth to an annual average 570 kb/d per year, down steeply from record gains of 1.9 mb/d achieved in 2014 and from 1 mb/d on average in 2010-14. As for OPEC, the producer group is expected to lift crude oil output capacity by an annual average of just 200 kb/d, with the bulk of the increment centred in a single country, Iraq. The world's total oil production capacity is thus expected to grow at an annual rate of 860 kb/d over the forecast period.

The second consequence of recent market changes is that the geographic distribution of incremental supply is profoundly transformed as the producer response to the price collapse varies greatly by country. Remarkably, neither the price drop nor OPEC's policy to maintain its 30 mb/d production target, however significant the impact, seems likely to change the Americas' role as the main engine of non-OPEC supply growth in the medium term. North America and Brazil, despite major cutbacks in investment, remain the largest source of world supply growth, led by the United States. US LTO is now forecast to grow to an average 5.2 mb/d, bringing total US production to an estimated 14 mb/d by 2020. This will maintain the United States in its role as top liquids producer. Canadian production remains large at just under 5 mb/d in 2020, although growth is slower than before the price crash. Lower prices have resulted in annual growth of about 140 kb/d over the medium term, much lower than the 210 kb/d previously expected.

In contrast, production from Russia, Colombia and Norway will be more severely affected and will not grow over the medium term. In Russia, the effects of the price collapse on the economy are significant, compounded as they are by international sanctions that restrict companies' access to capital and OPEC's November 2014 decision to maintain its supply target. Russian production is now forecast to contract by about 560 kb/d to 10.4 mb/d in 2020, from 10.9 mb/d in 2014. At 10.4 mb/d, Russia's production would recede to its pre-2010 level.

Colombia and Norway are other non-OPEC countries poised to suffer reductions in growth. In Colombia, lower planned capital expenditures and continued attacks on oil infrastructure have resulted in steep cuts to the supply forecast. In Norway, where growth is expected mostly from high-cost projects, weaker prices have resulted in lower planned investment. The distribution of production cuts versus earlier expectations is thus largely focused in Europe, Africa and Asia, as opposed to the western hemisphere.

OPEC producers are also paring investment in response to lower oil prices, although there are contrasting supply responses to the new market conditions. For Iraq, the oil price decline and the worsening security situation after the ISIL land grabs of June 2014 raise daunting challenges, exacerbated by the refusal of other OPEC producers to cut output. Despite these challenges, Iraq turned in a robust production and export performance in late 2014. It is forecast to expand capacity by 1.1 mb/d by 2020, accounting for nearly 90% of growth for the group as a whole. For a producer such as Venezuela, however, the market developments seem to be exacerbating problems that were already plaguing production before.

Many factors account for the range of producer responses to new market conditions, reflecting sharp differences in their cost of production - financial reserves, access to capital, technological know-how, asset portfolio and non-oil budget requirements. Capacity expansion plans may, in some cases, be fast-tracked on the back of lower production costs, favourable changes in foreign exchange rates and modified tax and regulatory structures designed to drum up investment.

Importantly, production costs are falling, particularly in North America. And as the cost of finding and extracting oil decreases, less money will need to be spent to pump the same amount of oil. Lower oil prices will also lead to greater budget discipline and efficiency, resulting in only those projects coming online that are not complex or do not require relatively risky investment. More often, however, tumbling prices will have an adverse effect on production growth. The weaker oil prices of today are leading to rigorous capital discipline at oil companies – both international and national – which means that new development projects may not be sanctioned.

Elevated supply risks will also be a major feature of the next six years. The year 2014 saw an increase in security and social stability risks in producer countries, particularly from Islamist groups operating in Syria, Iraq and Libya. ISIL has declared a self-styled “Caliphate” in the areas under its control. It has reportedly made attacks on Saudi soil and has threatened attacks in Jordan and elsewhere. Other, rival Islamist groups are also fighting in Syria. In Libya, an Islamist movement, Libya Dawn, has established a self-styled government that is vying for control of the country. In Nigeria, Islamist group Boko Haram is waging murderous attacks in the country’s north and has established control over large swathes of territory.

These movements’ effect on oil production has been mixed: no impact to date in Nigeria, where output is centred in the south; mixed effects in Iraq, where it is a disincentive to investment but also a prod for Baghdad and the Kurdistan Regional Government (KRG) to ramp up supply and boost much-needed income as fast as possible; and an overwhelming impact in Libya and Syria, where output has been reduced to a trickle. Significant production of some 350 kb/d is also at risk in Yemen and South Sudan. Assessing the political and military prospects of those groups is beyond the scope of this *Report*. Suffice it to say they are likely to continue to raise a significant supply risk and lower oil prices will make this risk even bigger.

Other countries such as Russia and Venezuela are likely to experience heightened social-stability and supply risks as a result of lower oil prices. Russia is facing major headwinds in the current price environment and has entered a deep economic recession. The second-largest non-OPEC producer relies on its oil and gas sectors for over 50% of its budget revenues. The low oil prices and sanctions-related restrictions on technology and financing all present severe challenges to its oil sector, exacerbating the overall effect of natural declines at the country’s brownfields. Among OPEC producers, Venezuela, already in the grip of recession, is perhaps the hardest hit by oil’s rout. Not only is social stability at risk, competing demands for cash are drying up the capital available for upstream investment.

Not all risks are to the downside. In Iran, production could increase dramatically in the event of a deal between Iran and the P5+1 over Tehran’s nuclear programme. Capacity additions in Iran reflect the assumption that current sanctions will remain in place. Iranian capacity may be expanded beyond the current forecast should sanctions on the oil sector be removed or further eased. Iraq could also surprise to the upside.

## OPEC’s diverging supply paths

Long-standing divisions in oil policies and price appetite between OPEC countries have been exacerbated by the oil price collapse. The group maintained unity at its ministerial meeting of 27 November when it relinquished, at least for now, its role as swing producer by maintaining its 30 mb/d supply target. But OPEC has always been fairly heterogeneous in makeup, with a fracture line running between Arab Gulf Cooperation Council (GCC) countries and most of the others.

Thus OPEC’s ability to weather the crisis varies greatly. GCC countries on balance look poised to adjust reasonably well, thanks to their relative political stability (they have been mostly spared from the turmoil of the “Arab Spring”), low production costs, relatively high institutional capacity, technological know-how, oil-sector professionalism and ample cash reserves. At the opposite end of the spectrum, countries like Venezuela, Nigeria and Angola, with higher costs, lower or nearly non-existent financial reserves, and - for at least some of them - high budget needs and social pressures, find themselves in a much more precarious situation. These countries may see production declines or substantially smaller growth than expected.

**Figure 2.3** OPEC crude production capacity

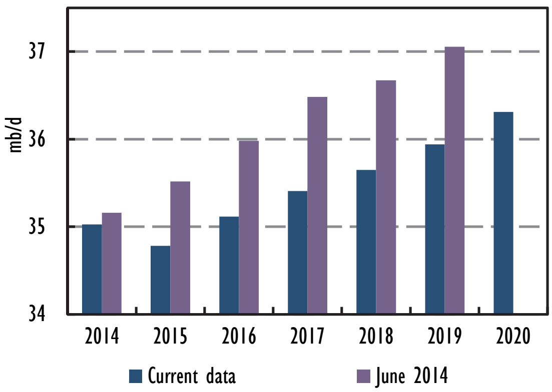
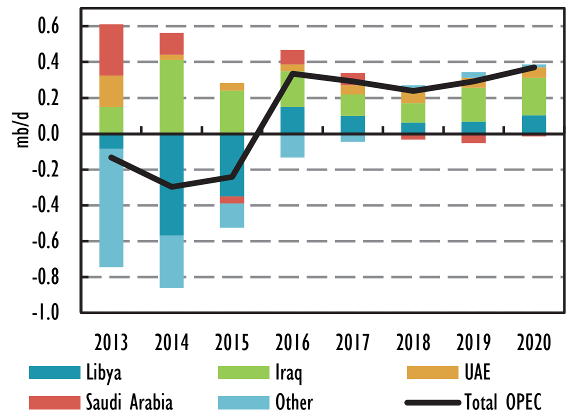



**Figure 2.4** Change in OPEC production capacity




Iraq and Iran are special cases. Iraq is marked by both an extraordinary, vastly under-tapped endowment of resources and exceptionally high challenges. Faced with a vicious Islamist insurgency in the northwest and revenue pressures due to the price collapse, the country, with high military expenses and no cash reserves to speak of, has every incentive to do everything in its power to overcome the largely self-imposed, above-ground hurdle that have long hindered production growth. But the security risks it faces remain significant: at best, ISIL looks likely to remain a major threat and investment hindrance, particularly in the early stage of the forecast. Despite the commendable strides achieved in late 2014, the security risks in the northern KRG and Kirkuk area as well as the oil-rich south cannot be dismissed.

As for Iran, it is constrained by international sanctions, which we assume in this *Report* will remain in place through the forecast period. But an agreement in talks with the P5+1, which would lead to a gradual lifting of sanctions, cannot be ruled out. Under the stewardship of Oil Minister Bijan Zanganeh, re-appointed by President Hassan Rouhani in 2013, Iran has also managed to reduce the influence of the Revolutionary Guards and their commercial enterprises, who, closely allied with Rouhani's predecessor, had extended their control of the sector and proved ineffective in managing it. Depending on the outcome of the nuclear talks, Iran could thus find itself in a position to quickly ramp up output towards its substantially higher capacity level.

The oil price decline is also leading OPEC to scale back investment. For the next six-year period, the group's capacity is forecast to grow at an annual 200 kb/d versus nearly 350 kb/d in *MTOMR 2014*. Iraq is expected to account for the overwhelming majority of this growth, making it precarious. The UAE shows notable expansion, but the oil price drop is dimming prospects in Venezuela, Nigeria and Angola. OPEC's largest and most influential producer, Saudi Arabia, looks content for now to sustain existing capacity of around 12.4 mb/d. It could, however, quickly advance expansion plans to add additional volume should market conditions warrant.

OPEC's capacity growth is forecast to lag non-OPEC, but that is not to say OPEC's policy to defend market share is ineffective: starting in 2016, the call on OPEC is forecast to begin rising. By the end of the decade the call rebounds to 32.1 mb/d – 2.7 mb/d over the average call for 2014 - as reduced capital expenditure among non-OPEC producers slows production growth.

**Table 2.1** Estimated sustainable crude production capacity (mb/d)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2014-20 |
|---|---|---|---|---|---|---|---|---|
| **Algeria** | 1.17 | 1.14 | 1.10 | 1.06 | 1.02 | 0.98 | 0.95 | (0.22) |
| **Angola** | 1.77 | 1.80 | 1.80 | 1.84 | 1.86 | 1.86 | 1.86 | 0.09 |
| **Ecuador** | 0.57 | 0.57 | 0.57 | 0.58 | 0.59 | 0.59 | 0.59 | 0.02 |
| **Iran** | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | (0.00) |
| **Iraq** | 3.66 | 3.90 | 4.10 | 4.22 | 4.33 | 4.52 | 4.73 | 1.07 |
| **Kuwait** | 2.86 | 2.82 | 2.84 | 2.84 | 2.83 | 2.80 | 2.76 | (0.10) |
| **Libya** | 0.85 | 0.50 | 0.65 | 0.75 | 0.81 | 0.87 | 0.98 | 0.13 |
| **Nigeria** | 1.98 | 1.92 | 1.91 | 1.90 | 1.89 | 1.89 | 1.89 | (0.09) |
| **Qatar** | 0.73 | 0.70 | 0.70 | 0.71 | 0.72 | 0.73 | 0.73 | (0.00) |
| **Saudi Arabia** | 12.38 | 12.34 | 12.42 | 12.49 | 12.46 | 12.41 | 12.39 | 0.01 |
| **UAE** | 2.90 | 2.94 | 2.98 | 3.03 | 3.10 | 3.15 | 3.21 | 0.31 |
| **Venezuela** | 2.56 | 2.49 | 2.45 | 2.40 | 2.45 | 2.51 | 2.56 | (0.00) |
| **OPEC** | **35.03** | **34.73** | **35.12** | **35.41** | **35.65** | **35.91** | **36.24** | **1.22** |

Barring any disruption, the group's spare production capacity is expected to remain ample by the end of the decade, but to narrow to 4.1 mb/d, versus 5.6 mb/d in 2014. Libya's capacity slumps in the early part of the forecast as armed conflict has escalated since late 2014 – offsetting anticipated gains from Iraq. Thus OPEC production capacity is expected to contract for a third straight year in 2015 – dropping to 34.7 mb/d from 35 mb/d in 2014. Growth returns in 2016 as Libya is expected to gradually recover and stands at 330 kb/d by the end of the decade, at which point prices and demand are expected to be higher.

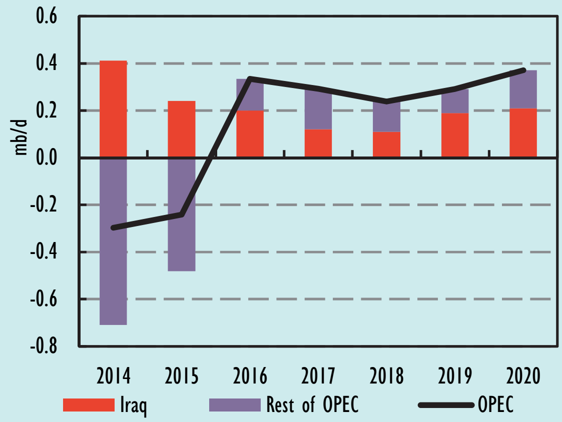
### Box 2.1 Oil rout, ISIL pose twin challenges to Iraqi growth

Low oil prices are for **Iraq** – already beset by challenges, not least a brutal ISIL insurgency - both a constraint on output growth and an incentive to speed up oil development and generate export revenue as quickly as possible. Output capacity is projected to expand by 1.1 mb/d by the end of the decade, to 4.7 mb/d, accounting for nearly 90% of OPEC's total forecast growth. There are considerable risks to this *Report's* forecast: to the downside given the country's steep security, financial, logistical and institutional hurdles but also to the upside given Iraq's vast, low-cost resources and severe budgetary pressure to maximise production.

Since ISIL's sweep through the north in June 2014 and the start of the price plunge, Iraq has shown impressive growth – with output, including production from the KRG, surging to a 35-year high of 3.7 mb/d on average for December 2014. Gains have spanned its three main producing regions: the south (which provided most of the growth); the northern Kirkuk area (which ISIL's advance had all but shut in) and semi-autonomous northern Kurdistan (where exports through the KRG's own pipeline to Turkey have risen).

**Box 2.1** Oil rout, ISIL pose twin challenges to Iraqi growth (continued)

**Figure 2.5** Capacity growth: Iraq vs rest of OPEC




Progress had been made by overcoming hurdles of various nature. Regarding the north, the new government of Iraqi Prime Minister Haider Abadi has shown more willingness to reach a permanent resolution to the long-running feud with the KRG over oil and exports. A surprisingly positive outcome of the deepening military and budget crisis has been to spur the two sides to strike an end-2014 deal that facilitated KRG crude exports and re-opened an outlet for Iraq's northern exports which had been shut in for nearly a year by Islamist forces. In the giant oil fields of the south – hundreds of kilometres from the front line – the main hurdles are down to infrastructure, administrative procedures and logistics, and Iraq's new oil minister Adel Abdul-Mahdi has impressed with his business-like approach and willingness to tackle these long-running issues.

While these positive steps are commendable, the elevated security and financial risks in Iraq - along with infrastructure challenges - are likely to limit the potential for growth from oil fields that straddle massive reserves. At least in the early years of the forecast period, ISIL is likely to remain a major threat which slows investment in the north. And with very little cash in the bank, Iraq may have limited capacity to pay international oil companies (IOCs) for their development work in the south. Since Iraq's ambitious oil expansion began in earnest in 2010, IOCs in charge of mega- projects at the country's prized southern oil fields have spent tens of billions of dollars to raise capacity by more than 1 mb/d to beyond 3 mb/d. It is critical for companies – already constrained on capital expenditure before the oil price drop - to get almost immediate reimbursement, otherwise project economics will be degraded. Further growth will cost a huge amount and the IOCs will want assurance of repayment for drilling programmes and surface facilities as well as long lead-time water injection and gas infrastructure projects.

To make the most of Iraq's southern oil fields such as Rumaila – the country's biggest producer - West Qurna-1 and Zubair, it is crucial to get a long-delayed water injection scheme, which underpins Iraq's massive upstream expansion, up and running. The immediate challenge is to prevent further declines at these fields, which have so far been insulated from ISIL. Production at West Qurna-1, for example, has sunk from a peak of around 600 kb/d to roughly 350 kb/d. Frustrated by the lack of progress, the IOCs running oil field projects are seeking to set up their own water injection schemes. Baghdad, however, would prefer to proceed with the USD 5 billion Common Seawater Supply Project (CSSP), which is not expected to be up and running until 2019 at the earliest. In the shorter term, the lack of adequate pipeline capacity is constraining output in some fields; and more generally, the shortage of storage tanks on the coast means some supply still has to be shut in if bad weather at the oil ports hampers loadings.

Companies operating in northern Kurdistan are meanwhile growing increasingly frustrated by the KRG's failure to pay them fully for the oil they have brought online and exported. And while Kurdish Peshmerga and Iraqi forces, supported by US air strikes, have had some success in containing the militants that threatened oil operations in the north, investment in the region has slowed.

In the near term, Iraq's prospects for higher exports and production hinge on the sustainability of the December Baghdad-KRG accord. Both sides need the agreement, but there are many sticking points that could undo it. The KRG will find it difficult to boost capacity significantly beyond current levels of roughly 400 kb/d without a steady flow of funds from Baghdad to pay investors. The region's core producers of Taq Taq (130 kb/d), Tawke (125 kb/d) and Khurmala (95 kb/d) make up the bulk of current capacity.

### Box 2.1 Oil rout, ISIL pose twin challenges to Iraqi growth (continued)

For the central government, the deal provides an outlet – via the KRG's own pipeline system – for its northern Kirkuk crude. Baghdad had been shipping close to 300 kb/d from its northern fields until a federally controlled pipeline to Turkey was shut in early March 2014 due to repeated attacks by ISIL militants. The KRG has been shipping its oil independently of Baghdad via its pipeline to Turkey since the end of May. The export deal of December 2014 calls for the KRG to provide 250 kb/d to Iraqi oil marketer SOMO to sell and allows for another 300 kb/d from Kirkuk to flow through the KRG's pipeline. In return, the central government is to release the KRG's 17% share of national revenue.

**Map 2.1** Iraq's oil infrastructure


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

**Box 2.1** Oil rout, ISIL pose twin challenges to Iraqi growth (continued)

In early January, Iraq's federal North Oil Company (NOC) began exporting 150 kb/d from the Kirkuk field's Baba dome and the Jambur oil field. The crude is routed through a new pipeline that links the fields to the KRG's export system. In addition to its own capacity, the KRG is drawing around 120 kb/d of production from the Kirkuk field's Avana dome and the nearby Bai Hassan, which NOC had previously managed. Following ISIL's summer land grab, the KRG took control of these northern assets. The giant Kirkuk oil field is divided into three geological formations: Avana, Baba and Khurmala. The KRG has been running Khurmala, the northernmost dome, since 2008.

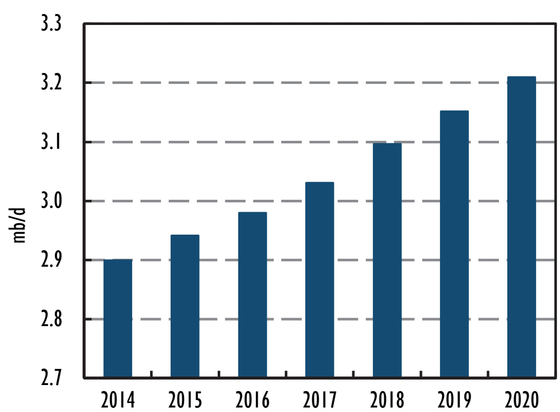
Remarkably, the oil price collapse and ISIL's advance have not dramatically slowed Iraq's growth prospects since the *MTOMR 2014*. Annual average growth is forecast at around 180 kb/d in the 2014-20 period, compared to 215 kb/d in the previous *Report*. But this should not conceal significant challenges on the ground. Both Iraq and the KRG have shown resilience and resourcefulness, but more will be needed to raise the country's production to its potential.

After Iraq, the **UAE** posts the most significant medium-term capacity boost – a projected rise of 310 kb/d to 3.2 mb/d in 2020. Despite oil's rapid descent, Abu Dhabi has vowed to press ahead with an ambitious official target of 3.5 mb/d by the end of the decade.

Underpinning its growth prospects, Abu Dhabi - at the time of writing - had begun to award stakes in its giant onshore concession, with France's Total the first to win a place. State Abu Dhabi National Oil Company (Adnoc) said in a statement that Total, which secured a 10% share, had presented the best technical and commercial offers. It said more companies would soon be added to the new 40-year operating partnership that will handle output of 1.6 mb/d. Adnoc opened the contest in 2012 to renew the concession for its onshore oil fields formerly operated by Abu Dhabi Company for Onshore Oil Operations (Adco), which held a 60% interest, with Total, BP, ExxonMobil, Royal Dutch Shell and Partex holding the remainder. Nine Western and Asian oil companies had bid for stakes in the Adco concession contract after the deal dating back to the 1970s expired in January 2014. The new contract terms reportedly offer a per barrel fee of near USD 3/bbl, an upward adjustment from the previous modest USD 1/bbl fixed fee. Offshore concession deals finish in 2018.

The largest addition to UAE production in the medium-term is due from the offshore Upper Zakum field – one of the world's biggest - with a boost of 250 kb/d to 750 kb/d. The completion date of the project, with an estimated cost of USD 10 billion, was already pushed back to 2017 from 2015 before the oil price fell. Zakum Development Co. (Zacdo), the joint venture that operates the field, is held 28% by ExxonMobil, 12% by Japan's Jodco and 60% by Adnoc. Umm Lulu, Nasr and Satah al-Razboot (SARB) are also due to add to offshore capacity. First oil came online from Umm Lulu in October 2014 – more than a year behind schedule.

**Figure 2.6** UAE crude production capacity



The UAE's pace of expansion has slowed from *MTOMR 2014* as project delays set in before the price of oil began to tumble. While the oil price crash has made the low-cost reserves in the UAE look even more attractive, it has also led to corporate belt tightening that may make it difficult for foreign companies at work in this core Gulf producer to speed up capacity building.

Oil's collapse has dimmed the outlook for growth in **Angola**, Africa's second biggest producer. Capacity is expected to edge up to 1.9 mb/d by 2020 for a gain of 90 kb/d versus an estimated 360 kb/d in *MTOMR 2014*. Angola and fellow West African producer Nigeria are under severe budgetary pressure that will impact their ability to fund costly deep-water projects with foreign partners. Even before oil began to drop, Angola's official 2 mb/d target looked elusive given myriad technical problems afflicting its deep-water projects. Further delays are likely as lower oil prices lead some foreign oil companies to review these expensive developments. Regulatory uncertainty and hold ups in contract approvals are also likely to set back projects. It is crucial for Angola, which relies on oil exports for 80% of state revenue, to start up new oil fields in order to offset steep decline rates that are as high as 15% at some of its deep-water reservoirs.

The country has a number of deep-water projects on the drawing board, but the challenges posed by low oil prices as well as water injection systems and floating production, storage and offloading (FPSO) facilities are likely to postpone some start-ups. Chevron's 110 kb/d Mafumeira Sul is due to come online in 2015. Total's 160 kb/d deep-water Cravo, Lirio, Orquidea and Violetta (CLOV) project started up in July and the French oil major's USD 16 billion, 200 kb/d ultra-deepwater Kaombo project is due to start up in 2017. The first sub-salt development, the 100 kb/d Cameia field, is unlikely to take place during the forecast period as the outlook for Angola's sub-salt acreage looks uncertain due to declining oil prices and disappointing drilling results.

In **Nigeria,** Africa's top producer**,** capacity is expected to contract by about 90 kb/d over the forecast period and sink to 1.9 mb/d as the oil sector is plagued by an array of daunting above-ground challenges and finds it ever harder to market its oil. Investment in high-cost deep-water projects had already slowed due to the long-running deadlock over the Petroleum Industry Bill (PIB) - and the sharp decline in oil prices will lead to further delays. Nigeria's inability to pass the controversial reform legislation to reorganise the state oil company and adjust fiscal contract terms has postponed final investment decisions and created a climate of uncertainty, now heightened by a drop in oil revenues and the presidential election in February. The PIB is unlikely to be passed into law before the expiry of the National Assembly's term in May. Plans for capacity growth are also being threatened by large-scale oil theft and pipeline sabotage in the restive Niger Delta oil heartland and rising violence by Islamic extremists Boko Haram.

The oil price decline is meanwhile causing severe budgetary stress as Nigeria faces a closely fought presidential election on 14 February. President Goodluck Jonathan is under fire over his management of the economy as well as his handling of security issues. It is unclear whether the presidential poll will produce a new government capable of reforming the oil industry and tackling the socio-economic issues in the Niger Delta and in the north with Boko Haram. Nigeria, which relies on oil for about 80% of government revenues, has been hit especially hard by the US LTO boom that has virtually wiped out US demand for its similar-quality light, sweet crude. Since the spring of 2014, Nigerian crude sellers have been reported as having difficulty finding buyers for their crude, which is being routed to Asia and Europe. Nigeria's biggest projects due online in the medium term are the 225 kb/d Bonga SW and Aparo deepwater fields and the 200 kb/d offshore, deepwater Egina.

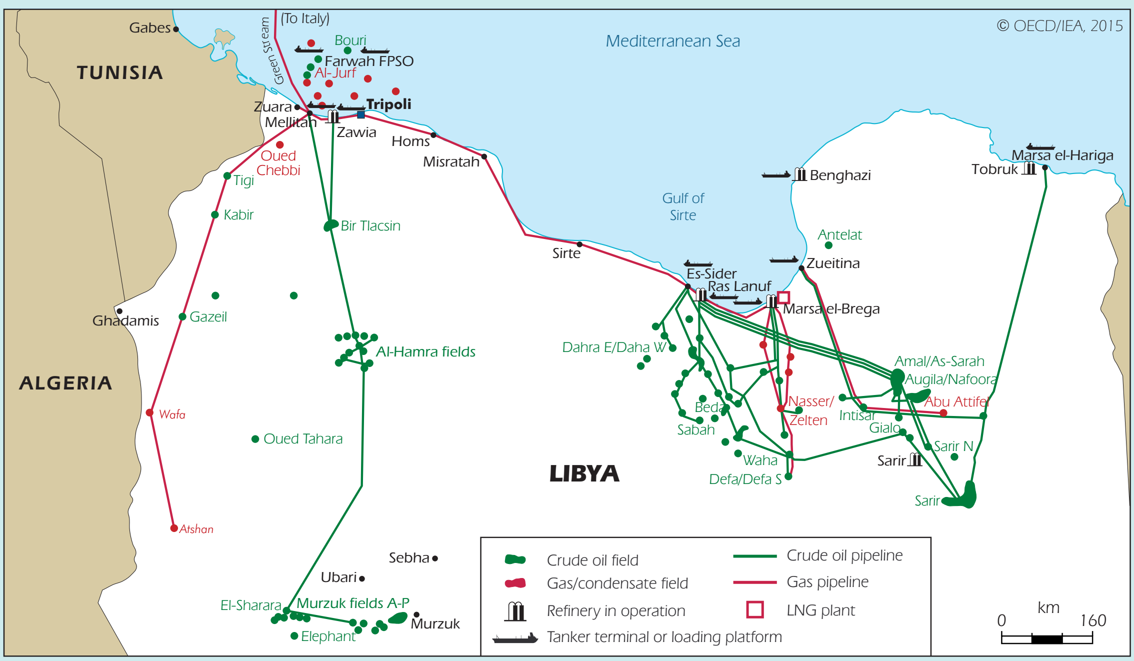
## Box 2.2 Libyan capacity at risk from militant attacks

**Libya** is OPEC's wildcard when it comes to capacity growth. Its prospects are fading somewhat as the country is engulfed in deepening chaos and its armed conflict enters a more dangerous phase with the direct targeting of energy infrastructure. Although production briefly scaled the 1 mb/d mark in October 2014, subsequent attacks on oil fields and ports have degraded operations in this North African producer. Capacity is forecast at an average 500 kb/d in 2015 before it gradually recovers to 980 kb/d by 2020. In the near term, it may prove difficult for Libya to sustain, let alone build, capacity as rival governments fight for control over the country's oil assets and a UN-backed peace process flounders. Output is not expected to revisit pre-civil war levels of nearly 1.6 mb/d any time soon.

Libya's oil fields are now technically capable of sustaining output of much more than 500 kb/d, but the execution of crucial well maintenance and infrastructure upgrades is impossible to carry out while violence rages between the officially recognised government that fled to Tobruk in the east and the administration run by the so-called Libya Dawn that took over Tripoli last summer. The raging violence has caused expatriate oil workers, essential for more technical work, to be repatriated.

At the end of 2014, a major blow was dealt to Libya's oil sector when a rocket attack by Libya Dawn forces struck crude storage tanks at the country's biggest oil export terminal Es Sider, in the east. The resulting fires at the vital terminal reportedly damaged six of 19 tanks and destroyed more than 1 mb of crude. With the front line between rival armed groups established in the area, it will be very difficult to rebuild the tanks that were taken out of action.

### Map 2.2 Libya's oil infrastructure




This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The shut-down of Es Sider and the nearby Ras Lanuf terminal – which together can handle 560 kb/d of exports – is a substantial setback to production. The Waha Oil Company, the biggest producer in the Sirte Basin oil heartland, has shut its fields, which had returned to full production of some 340 kb/d. The closure of Ras Lanuf led Wintershall, which had been producing some 35 kb/d from its onshore fields, to cut output.

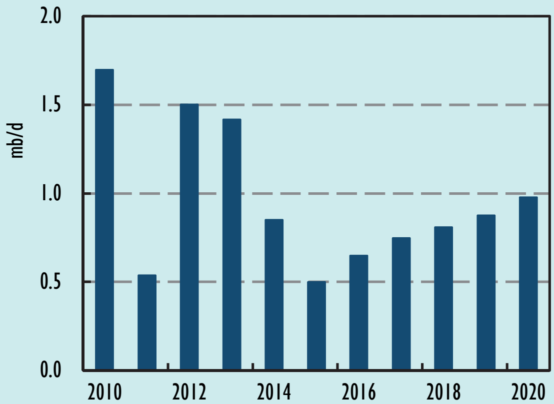
**Box 2.2** Libyan capacity at risk from militant attacks (continued)

The Libyan oil sector has nonetheless demonstrated its resilience several times recently, so it might be unwise to write it off. The speedy return of production after the civil war of 2011 exceeded all expectations. And again in June 2014, the end of a year-long oil port blockade by rebels seeking greater regional autonomy resulted in a rapid, if short-lived rebound in production and exports. Pumping reached 1 mb/d by October, but the comeback was undone by renewed unrest at core producing oil fields and export terminals. Protests in December 2014 led to the closure of the 350 kb/d El Sharara field – the country's biggest - and the nearby 130 kb/d Elephant field in the remote southwest.

The internationally recognised government in Tobruk is expected to retain control of the eastern Sirte Basin, therefore much of the region's production – including the core Waha, Sarir and Mesla fields – should eventually ramp up. The west, home to newer oil developments, may prove more unstable. Oil fields in the west are the prize in a struggle between militias supporting rival governments.

In Tobruk, Prime Minister Abdullah al-Thinni represents the country's new parliament, the House of Representatives. In Tripoli, self-declared Prime Minister Omar al-Hassi is heading a government supported by a group of Islamists, militias from the western town of Misrata and former General National Congress parliamentarians. Each side has appointed its own officials to run the state oil company NOC and the oil ministry, creating confusion over who is in charge. While the United States and Europe have little interest in military involvement in Libya, regional governments are growing more engaged. Egypt and the UAE have provided military assistance to the Libyan National Army, which supports al-Thinni and is led by former Gaddafi army general Khalifa Haftar.

**Figure 2.7** Libya crude production capacity




Nearly USD 200 billion in foreign reserves offer **Algeria** some short-term protection from the pain of low oil prices. Spending on social programmes could, however, be reduced if prices stay low for a prolonged period. Regardless of oil's sharp decline, state oil company Sonatrach intends to invest USD 90 billion in the oil and gas sector from 2015-19. Despite this ambitious plan, Algeria's production capacity is expected to decline by 220 kb/d to 950 kb/d in 2020 due to a long period with no projects and very little commerciality.

Prospects for growth have also been set back by security concerns after the kidnapping and execution of a French tourist in September 2014 as well as bureaucratic inertia. There is lingering unease following the deadly 2013 attack on the In Amenas gas facility, and the free-flow of weapons and Islamist militants from neighbouring Libya since the fall of Gaddafi is a growing concern for international oil companies.

A long period with no projects on its books has, however, spurred Algiers – heavily reliant on oil and gas revenues for its state budget - to improve its fiscal regime post In Amenas. Exploration and development of new fields is at a standstill despite an impressive resource base and Algiers' last licensing round in September 2014 failed to drum up much interest as the sweeter commercial terms apparently did not offer adequate incentives. The North African country is seeking to exploit its enviable shale gas assets and is negotiating with international oil companies.

A major Middle East supply boost could arrive courtesy of **Iran**, where production capacity is currently estimated at 3.6 mb/d. Stringent international sanctions have reduced Tehran's output to roughly 2.8 mb/d for the past several years. Yet people familiar with the Iranian oil industry, including Iranian oil industry representatives and third-party foreign experts with direct knowledge of the sector, indicate that Tehran has the ability to raise output by around 800 kb/d within months.

This forecast does not take a view on the outcome of negotiations between Tehran and world powers over its nuclear programme and assumes that sanctions remain in place through the forecast period. The deadline for talks between Tehran and the P5+1 has been extended to June 2015. Under an interim agreement struck in 2013 with the US, UK, France, Russia, China and Germany, Tehran suspended some of its nuclear activities in exchange for some easing of sanctions.

The National Iranian Oil Company (NIOC) has already begun preparing for the day when rigorous financial measures are lifted. Advance planning started once veteran technocrat Bijan Zanganeh returned to the post of oil minister in 2013, and much of last year was spent making sure wells and processing units were up to scratch and pipeline systems were tested.

If anything, some of Iran's core oil fields may have been revived under sanctions: shutting down large volumes of oil may have allowed pressure to rise – leaving them capable of a swift production boost. Industry experts reckon it may take less than three months to ramp up output by 600 kb/d to 800 kb/d, thus lifting flows to capacity of 3.6 mb/d. Most of the immediate supply boost would come from the Iran's big three fields of Ahwaz, Marun and Gachsaran. Smaller fields such as Karanj, Parsi and Raq-e-Safid would also contribute. There is another tier of still smaller fields such as Shadegan that would also be expected to help.

Oil Minister Zanganeh, who ran the oil sector under former President Mohammed Khatami, is widely respected by the international oil companies and credited with increasing Iran's production during a first round of US sanctions. He has vowed to return Tehran to OPEC's number two slot after Saudi Arabia – a position now held by neighbouring Iraq - as soon as sanctions are removed.

That will require hefty investment and, to that end, Iran's oil ministry has prepared a new upstream contract to lure foreign oil companies. Top officials from a number of Western oil majors have already met publicly with Zanganeh to express their interest. While the new Iran Petroleum Contract (IPC) is a vast improvement on the unpopular buy-back model – which compensates foreign companies with production - potential investors are keen to see further details on commercial terms.

If projects were to be awarded swiftly, capacity could gradually rise towards 4 mb/d. In the meantime, Tehran would potentially have access to increased capital - allowing it to boost capacity on its own. The country's production peaked in the 1970s at just over 6 mb/d. Capacity had recovered to around 3.9 mb/d in 2010, but slipped after sanctions squeezed Iran's ability to fund projects to sustain that lofty rate.

The first projects expected to be on offer are for enhanced oil recovery at the ageing onshore fields of Ahwaz, Marun, Gachsaran – the backbone of Iran's production – as well as the smaller onshore fields of Agha Jari and Bibi Hakimeh. Roughly 50% of the country's production comes from fields that are more than 70 years old and in desperate need of rehabilitation through new technology. Tehran is also giving priority to development of fields that straddle the border with Iraq – Azadegan and Yadavaran are targeted to reach 700 kb/d.

**Saudi Arabia** is expected to sustain its production capacity near its official 12.5 mb/d target throughout the forecast period. With an estimated USD 750 billion in foreign exchange reserves, Riyadh has a hefty cash cushion that could see it through several years of low oil prices. Saudi Aramco's Chief Executive Khalid al-Falih has, however, said that the low oil price environment has created an opportunity for the state oil company – and the industry as a whole - to sharpen fiscal discipline.

To keep capacity at roughly 12.4 mb/d by 2020, new oil fields are due to come online to offset ageing production. Riyadh is striving to maintain, rather than boost, oil output capacity as it seeks to develop non-associated and conventional gas reserves. Gross capacity additions of 550 kb/d are expected to be brought online during the forecast period following the ramp-up of the Manifa field's capacity to 900 kb/d at the end of 2014. Output of heavy crude from the giant offshore Manifa field is designated for the country's new refining joint ventures with Total at Jubail and Sinopec at Yanbu. A 250 kb/d upgrade at the Shaybah oil field, which pumps Arab Extra Light, is due to lift capacity to 1 mb/d starting in 2016. Saudi Aramco is also due to add an extra 300 kb/d of Arab Light capacity to the 1.2 mb/d Khurais field in early 2017.

The new capacity will help make up for natural decline rates and allow Saudi Aramco to reduce capacity at Ghawar, the world's biggest oil field. This may allow for better reservoir management and ultimate recovery. If required, Saudi Arabia could increase capacity beyond its target. Three fields could add a further 1.9 mb/d: Zuluf could provide 900 kb/d of Arab Medium, Berri could contribute 300 kb/d of Arab Extra Light and Safaniyah – the world's largest offshore oil field – could add 700 kb/d of heavy crude.

**Kuwait's** capacity is forecast to edge down to 2.8 mb/d by 2020, a decline of 100 kb/d over the forecast period. In the near term, Saudi Arabia's unilateral closure of the jointly shared Neutral Zone oil field of Khafji is expected to put some strain on capacity. Despite oil's rout, Kuwait is pressing ahead with an extensive programme of drilling, well workovers and de-bottlenecking to raise production capacity. The giant Burgan field in southern Kuwait is also expected to benefit from a planned water injection scheme to help keep capacity at a steady 1.7 mb/d beyond this decade. These combined efforts have led to an upward revision from *MTOMR 2014*. Kuwait's official target is to reach capacity of 4 mb/d by 2020 through investment of nearly USD 50 billion, but this goal looked ambitious even prior to oil's decline and the Neutral Zone situation.

There is meanwhile a growing awareness within the management at state-owned Kuwait Oil Company (KOC) – led by veteran technocrat Hashem Hashem - that Kuwait would benefit from the expertise, project management and technology that IOCs can provide to tap the country's geologically challenging reserves, industry sources say. To that end, KOC has invited a number of major oil companies to express their interest in several crucial projects, including the Ratqa oil field - a large resource base of heavy oil near the northern border with Iraq. International oil companies are digesting the terms of the new enhanced technical service agreement (ETSA) contract that is on offer. The plan is to pump 60 kb/d from Ratqa by 2018 and then ramp up to 120 kb/d by 2025. Major oil companies such as Total, ExxonMobil, BP and Chevron have all previously looked at working with Kuwait on enhanced oil recovery projects. Hurdles are likely to lie ahead: strenuous domestic opposition to foreign involvement in Kuwaiti energy has in the past forced long delays in projects.

**Qatar's** crude oil production capacity recovers to 730 kb/d by 2020 after slipping in the early years of the forecast period. It is relatively costly to develop Qatar's oil fields due to their complex geology, so raising capacity beyond 730 kb/d may prove prohibitively expensive in the current low price environment. Keen to breathe new life into its declining oil fields, Qatar Petroleum has been planning to redevelop the onshore Dukhan field and double the 45 kb/d, offshore Bul Hanine field to 90 kb/d at an estimated cost of USD 11 billion. A core component of the costs is the redevelopment of the ageing infrastructure and installation of new offshore central processing facilities.

Denmark’s Maersk Oil is meanwhile seeking to maintain capacity at the 300 kb/d al-Shaheen field through a two-year rehabilitation programme that began in 2013. Similarly, US Occidental Petroleum is seeking to sustain current capacity levels at the 100 kb/d Idd al Shargi field, through a costly well development effort. Oil output in Qatar – the world’s largest LNG producer - peaked at 860 kb/d in early 2008 and has been on a downward trend ever since.

Within OPEC, **Venezuela** is perhaps the most vulnerable to the oil price slump, which is threatening its financial and social wellbeing and leaving it precious little cash to fund crucial capacity expansions. Oil output capacity in Latin America’s biggest producer, now estimated at around 2.6 mb/d, is expected to fall in the early part of the forecast period before recovering by 2020. State oil company PDVSA will reportedly make cuts in its 2015 spending.

With Venezuela already in the grip of recession, Caracas is seeking to develop its energy partnership with China. In early January, President Nicolas Maduro said he had secured more than USD 20 billion of new investment from Beijing. Caracas’ current level of spending is unsustainable: sinking reserves and chronic delays in economic reforms have raised the risk of a Venezuelan sovereign debt default. A proposed one-off sale of its US refining unit Citgo could raise up to USD 9 billion, but this is seen as a short-term fix.

International oil companies at work on the ground have so far been shielded from the economic upheaval because state Petroleos de Venezuela (PDVSA) needs their investment and skill to tap heavy oil projects in the vast Orinoco belt. But a prolonged period of low oil prices may make funding problematic and increase the burden on foreign partners.

There are already huge operational and organisational challenges in the oil sector and little maintenance is being carried out in the fields. More than half a dozen companies have abandoned projects in the Orinoco extra-heavy oil belt, where chronic project delays have pushed development far behind target. The ongoing cash crunch is a major factor setting back the Orinoco expansion. Capacity in the Orinoco Belt could grow by about 400 kb/d between 2018-20, but the overall production profile of conventional fields is declining so swiftly that the additional extra-heavy barrels are merely expected to even out the losses.

And in a bid to economise, PDVSA has started to purchase lighter crude oil from Algeria and Russia to dilute extra-heavy Orinoco crude and make it more desirable to refiners worldwide and for processing at home. The imported crude is cheaper than the naphtha that PDVSA had been buying to use as a diluent. Crude oil exports make up nearly all of Venezuela’s foreign exchange earnings.

Caracas is meanwhile supplying roughly 500 kb/d of crude oil to China, with part of that volume used to pay down oil-for-financing agreements. Beijing, which has lent Venezuela some USD 50 billion since 2007, has become Venezuela’s core source of overseas funding. Companies from China and Russia – another major lender via future oil deliveries until recent price declines and the imposition of international sanctions - are also invested in joint venture projects in the Orinoco Belt.

**Box 2.3** OPEC's gambit

OPEC's November 2014 ministerial meeting marked a seismic shift in its oil production policy. In the face of relentless growth in US LTO supply and plunging oil prices, the group that pumps roughly 40% of the world's oil chose to drop its defence of price in favour of market share. In a stroke, OPEC – led by Saudi Arabia - abandoned its decades-long role as swing producer by maintaining its 30 mb/d supply target. Top producer Saudi Arabia drove the decision to let the market balance itself: the country's influential oil minister Ali al-Naimi was reported as saying it was "not in the interest of OPEC producers to cut their production, whatever the price is". Riyadh has signalled its full support at the highest level for the policy, which was explicitly endorsed both by the late King Abdullah as well as his successor King Salman.

And with oil down more than 50% from its June peak, OPEC's battle for market share may only just be starting. OPEC, along with rival producers outside the group, has been targeting energy-hungry Asia – and China in particular – as a supply outlet for some time. Through its monthly formula prices, Saudi Arabia has sought to price its oil ever more competitively, leading other Middle East producers to follow suit. It has now become a buyers' market in Asia, with China growing more powerful as a purchaser.

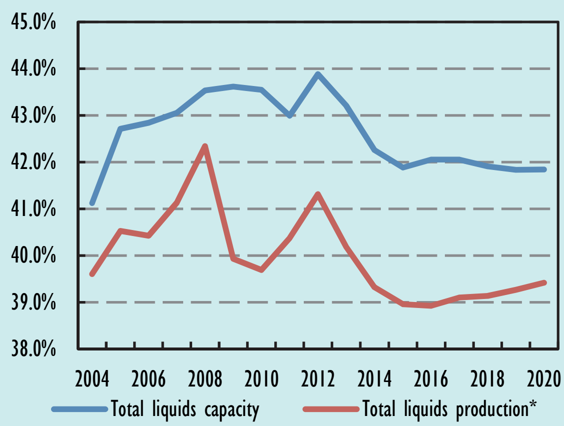
**Table 2.2** OPEC spare production capacity outlook 2014-20 (mb/d)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| **OPEC Crude Capacity** | 35.03 | 34.73 | 35.12 | 35.41 | 35.65 | 35.91 | 36.24 |
| **Call on OPEC Crude + Stock Ch.** | 29.44 | 29.43 | 29.87 | 30.54 | 31.02 | 31.58 | 32.12 |
| **Implied OPEC Spare Capacity*** | 5.58 | 5.30 | 5.25 | 4.87 | 4.63 | 4.33 | 4.13 |

* Spare capacity is defined as the difference between estimated OPEC capacity and the 'Call on OPEC + stock ch.'. Actual idle capacity is lower than spare capacity when OPEC produces above the 'Call'.

Going forward, a bigger challenge for OPEC will be to make room for an expanding Iraq and an Iran that – at some stage - becomes unshackled from rigorous international sanctions that have severely limited its production. That will not be easy. Iraq has already been routing much of its additional supply into China, stoking rivalry among fellow OPEC members, while Iran reportedly has offered favourable credit terms and pricing. Given the new oil market reality, competitive pricing may not be enough. Producer countries will have to revisit their crude oil marketing strategies, perhaps taking a more flexible approach on spot market sales and destination restrictions. And as Middle East countries such as Saudi Arabia and the UAE expand their downstream operations, refined products trade is likely to become more prominent in the overall marketing effort.

**Figure 2.8** OPEC share of total liquids




* Assumes crude production at OPEC target of 30 mb/d until 2016 and then projected at the 'Call on OPEC' from 2017 to 2020.

In terms of the global oil supply picture, OPEC's share of the market has been shrinking but looks set to edge up towards the end of the forecast period. After a recent peak above 42% in 2008, OPEC's share of total liquids production dropped towards 39% in 2014 due to a collapse in Libyan output and rising non-OPEC supply. Looking ahead, OPEC crude production is assumed at the group's official 30 mb/d target until the "Call" rises above this figure in 2017.

Feeling the pinch of lower oil prices, **Ecuador** - OPEC's smallest producer - has cut some low-priority projects in its oil sector. By 2020, production capacity in the Andean nation is forecast at 590 kb/d, up by 20 kb/d from 2014. Oil is one of the primary sources of export revenue for Ecuador's 15 million people and if prices continue to fall, public spending may be cut. Quito has looked increasingly to China as a major source of funding – including some loans that are supported by crude oil deliveries. In early January, Ecuador secured more than USD 7 billion in credit lines and loans from Beijing.

Much of Ecuador's capacity increase hinges on the successful development of the billion-barrel Ishpingo-Tambococha-Tiputini oil block in the Amazon rain forest. The government approved development of the block, which holds about a fifth of Ecuador's total reserves, despite protests from environmental groups. These heavy oil fields, located within a Unesco world biosphere reserve, are due to be tapped in 2016. Oil's swift drop may force state-owned Petroamazonas to seek foreign partners to help. Production capacity has gradually begun to rise after languishing for years as Quito struggled to attract foreign investment.

## *OPEC gas liquids supply*

OPEC condensate and NGL output is forecast to rise at a relatively swift pace given the group's focus on natural gas developments. Production capacity of OPEC condensate and other natural gas liquids, and non-conventionals is forecast to rise by 535 kb/d to 6.9 mb/d by 2020. Iran, pushing to ramp up despite rigorous international sanctions, accounts for more than half the total growth.

Rising domestic natural gas demand is driving **Iran's** push to boost production from the massive South Pars gas field. Iranian NGL capacity is estimated at 920 kb/d by 2020, for growth of 280 kb/d over the forecast period. Long delayed projects are being fast-tracked, though a large portion is expected to be earmarked for domestic use, including the petrochemical sector.

Development of South Pars has been set back by rigorous financial sanctions that have limited Tehran's access to much-needed equipment and technology that is vital to maintain and expand infrastructure. Iran launched the South Pars Phase 12 project in 4Q14, which includes new capacity of 75 kb/d of condensate and 30 kb/d of NGLs. Next online is South Pars 15-16, which is slated to bring on 80 kb/d of condensate and 30 kb/d of other gas liquids in 2018.

The holder of OPEC's largest NGL capacity, **Saudi Arabia**, is expected to increase production by around 145 kb/d to just under 2 mb/d by 2020. The massive 275 kb/d Shaybah NGL development, which includes 190 kb/d of ethane for petrochemicals feedstock, started up in late 2014. Higher output at the Manifa field has allowed for additional condensate production. Further gas development in the Hasbah and Arabiyah gas fields could provide additional condensate capacity.

**Qatar** condensate, natural gas liquids and non-conventional capacity – mostly from the giant North Field – is due to increase by 80 kb/d to just above 1.25 mb/d by 2020. The last big project to come online is the RasGas USD 10.3 billion Barzan gas project, which will add 50 kb/d to condensate capacity starting in 2015.

**Figure 2.9** OPEC NGL production capacity

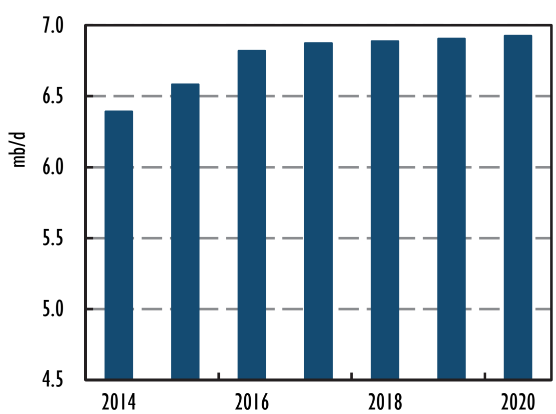


**Table 2.3** Estimated OPEC sustainable condensate & NGL production capacity (kb/d)

| Country | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2014-20 |
|---|---|---|---|---|---|---|---|---|
| Algeria | 457 | 484 | 494 | 474 | 454 | 434 | 434 | -23 |
| Angola | 74 | 78 | 140 | 140 | 140 | 140 | 140 | 66 |
| Ecuador | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Iran | 641 | 683 | 791 | 819 | 862 | 901 | 923 | 282 |
| Iraq | 87 | 88 | 88 | 88 | 88 | 93 | 93 | 6 |
| Kuwait | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 0 |
| Libya | 38 | 35 | 40 | 50 | 60 | 64 | 77 | 39 |
| Nigeria | 515 | 494 | 474 | 476 | 459 | 444 | 429 | -86 |
| Qatar | 1 174 | 1 219 | 1 234 | 1 257 | 1 257 | 1 257 | 1 257 | 82 |
| Saudi Arabia | 1 828 | 1 895 | 1 955 | 1 965 | 1 975 | 1 975 | 1 975 | 147 |
| UAE | 819 | 828 | 828 | 848 | 853 | 857 | 857 | 38 |
| Venezuela | 210 | 210 | 205 | 187 | 170 | 170 | 170 | -40 |
| **Total OPEC NGLs*** | **6 143** | **6 313** | **6 549** | **6 604** | **6 617** | **6 634** | **6 654** | **511** |
| **Non-Conventional**** | **251** | **271** | **271** | **271** | **271** | **274** | **275** | **24** |
| **Total OPEC** | **6 394** | **6 584** | **6 821** | **6 876** | **6 889** | **6 908** | **6 929** | **535** |

* Includes ethane.

** Includes gas-to-liquids (GTLs).

**Angola** is expected to increase gas liquids capacity by 65 kb/d to 140 kb/d following the long awaited start-up of Angola LNG (ANLG) in mid-2015. The project has been beset with problems and was shut in early May after a massive gas leak in April at the 5.2 mt/y liquefaction plant, which includes production of 50 kb/d of NGLs. The USD 10 billion Chevron-operated LNG plant has been hit with a series of technical problems since its June 2013 start-up.

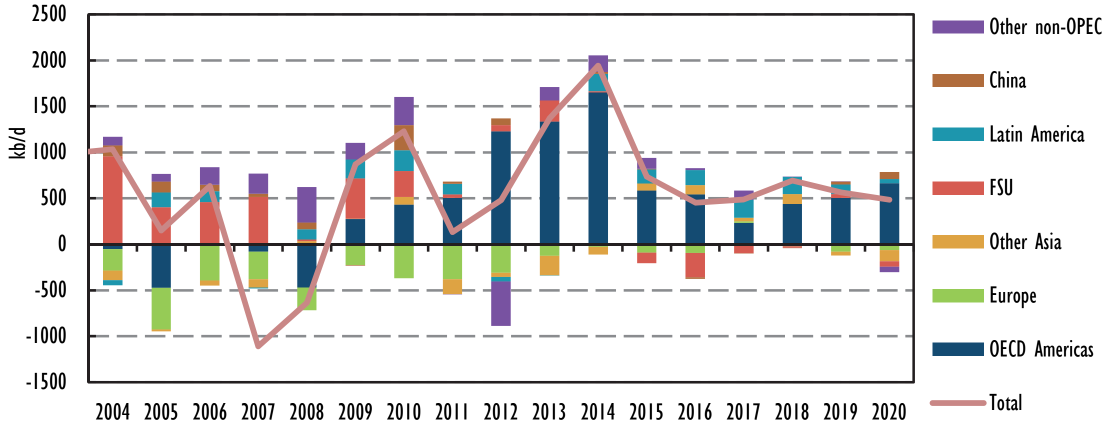
## Non-OPEC supply growth weakens on lower oil prices

The collapse in oil prices since June 2014, compounded by OPEC's move to suspend its role as swing supplier at its November 2014 meeting, has forced large-scale revisiting and reprioritisation of spending plans across the industry, resulting in lower production growth over the forecast period than previously expected. Overall, non-OPEC supply growth is now expected to be about 2.8 mb/d lower compared with last year's *Report*. OPEC's embrace of market forces has greatly changed expectations of future prices and producer behaviour, even as the price crash and signs of weak demand growth have put an immediate strain on companies' budgets. Industry participants will respond differently to these changed circumstances based on a variety of factors including, but not limited to, the specific costs and economics of their projects, the broader makeup of their asset portfolio, and their access to capital.

While North America will continue to be the backbone of non-OPEC supply growth in the next six years, lower prices are slowing down investment across the board. Non-OPEC production growth is expected to average roughly 570 kb/d annually though the forecast period, a dramatic slowdown compared with growth of about 1.9 mb/d in 2014, an exceptional year in terms of non-OPEC output increases, and down from average growth of 1 mb/d in 2010-14.

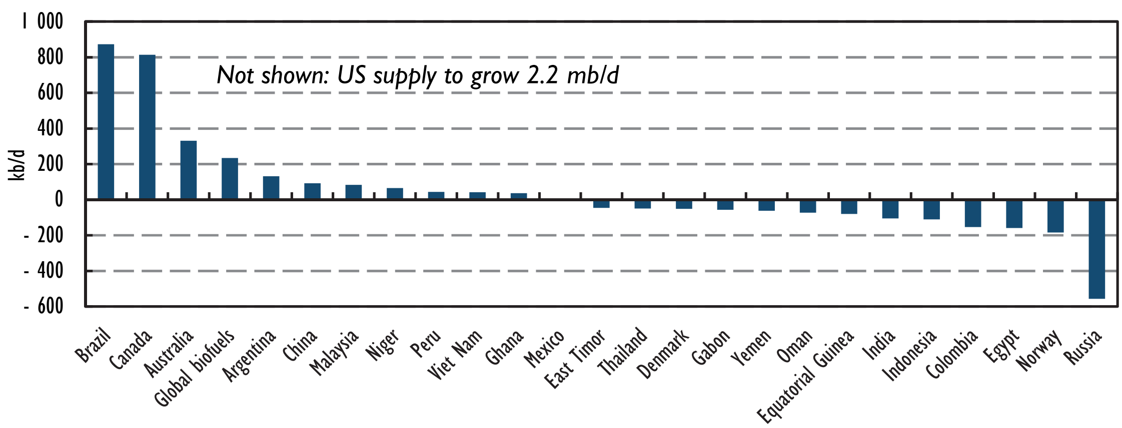
The recent fall in drilling activity across many non-OPEC producers coupled with announced capex reductions is a harbinger of the impending slowdown in production growth. The downturn in drilling has been particularly evident in the United States, where the number of rigs dropped by more than 200 in 4Q14. In early 2015, capex reductions were announced and the first casualties of the oil price revealed themselves as North American operators filing for bankruptcy protection, including Canada's oil sands focused Southern Pacific Resource Corporation.

**Figure 2.10** Non-OPEC supply: yearly change




In Canada, where much of the capex for projects due to come online by mid-2016 has already been committed, a reduction in spending will affect projects that are planned to start up beyond that time frame. In contrast to US LTO, Canada's growth is driven by projects with long pay-back periods and companies will be much more restrained in committing cash to fund expensive projects in the current price environment.

**Figure 2.11** Selected sources of non-OPEC growth/decline 2014-20




Brazil, which saw an impressive jump in production in the second half of 2014, is now expected to be the second-largest source of non-OPEC expansion through 2020. However, it, too, will see growth potential limited by lower crude oil prices. Although much of Brazil's production is profitable with crude at around USD 50/bbl, the enormous debt of national oil company Petrobras will limit the availability of investment to further develop the country's prolific pre-salt deposits and grow apace.

Russia, once considered a pillar of non-OPEC supply growth, is expected to swing into contraction over the medium term due to the crushing and mutually-compounding impact of lower oil prices and

Western sanctions. Low oil prices will hit investment in Russia's greenfield development in East Siberia, desperately needed to offset brownfield declines, and also cut into the availability of funds needed for field redevelopment and maintenance. As a result, not only will Russia see insufficient volumes from new fields but existing fields will also decline at a faster rate, a double-whammy which will result in decreased supply of about 560 kb/d by 2020. Lower prices will also wreak havoc on the production outlook in countries such as Colombia that were already challenged by insecurity and political instability.

Declines in production may not be as steep as investment drops might suggest, as oil production costs are also on the decline, particularly in North America. Although lower oil prices are putting enormous pressure on producers, the new market conditions are providing an impetus for companies to cut costs and operate more efficiently. Oil service costs in North America have fallen by about 15% over the last few months, partly offsetting cuts in announced capital expenditures. Some of the cost deflation is due to the current oversupply of rigs. Experimental drilling technologies also contribute to the increased efficiency, with companies employing drilling techniques such as superfracks to drive down per barrel production costs. Nonetheless, to cope with the new operating environment, the industry is likely to go through a period of consolidation, which has already started among oil service companies. The recent merger between Halliburton and Baker Hughes signals the way forward for many operators, large and small.

Lower upstream investment will slow supply growth, leading to a rebound in the call on OPEC as early as 2016. When that happens, US LTO may demonstrate a much greater ability to scale up production than conventional output and may find itself in a position to compete directly with OPEC as a source of swing supply. The short lead time and scalability of LTO production allow it to respond quickly to improving market conditions. Its astronomical rise since 2010 in response to high oil prices provides an insight into how LTO production could respond once market conditions take a turn for the better. On the other hand, LTO output is also elastic on the downside and growth is declining due to lower prices. However LTO's downside response has yet to be fully tested.

**Table 2.4** Non-OPEC supply (mb/d), 2014-20

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2014-20 |
|---|---|---|---|---|---|---|---|---|
| OECD | 22.6 | 23.1 | 23.6 | 23.9 | 24.5 | 25.0 | 25.6 | 3.0 |
| *OECD Americas* | 18.8 | 19.3 | 19.9 | 20.1 | 20.6 | 21.1 | 21.7 | 3.0 |
| *OECD Europe* | 3.3 | 3.2 | 3.1 | 3.2 | 3.2 | 3.1 | 3.0 | -0.3 |
| *OECD Asia Oceania* | 0.5 | 0.5 | 0.6 | 0.7 | 0.8 | 0.9 | 0.8 | 0.3 |
| Non-OECD | 29.6 | 29.7 | 29.5 | 29.7 | 29.7 | 29.7 | 29.5 | -0.1 |
| *FSU* | 13.9 | 13.8 | 13.5 | 13.4 | 13.4 | 13.4 | 13.4 | -0.5 |
| *Europe* | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | -0.1 |
| *China* | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.3 | 0.1 |
| *Other Asia* | 3.4 | 3.5 | 3.5 | 3.5 | 3.4 | 3.3 | 3.2 | -0.2 |
| *Non-OECD Americas* | 4.4 | 4.5 | 4.7 | 4.9 | 5.1 | 5.2 | 5.2 | 0.8 |
| *Middle East* | 1.3 | 1.3 | 1.2 | 1.2 | 1.2 | 1.2 | 1.1 | -0.2 |
| *Africa* | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.3 | 2.2 | -0.1 |
| **Non-OPEC ex PG and biofuels** | 52.2 | 52.8 | 53.2 | 53.6 | 54.2 | 54.7 | 55.1 | 2.9 |
| Processing Gains | 2.2 | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.5 | 0.3 |
| Global Biofuels | 2.2 | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.4 | 0.2 |
| **Total-Non-OPEC** | 56.6 | 57.3 | 57.8 | 58.3 | 59.0 | 59.5 | 60.0 | 3.4 |
| Annual Change | 1.9 | 0.7 | 0.5 | 0.5 | 0.7 | 0.6 | 0.5 | 0.6 |
| Changes from last *MTOMR* | 0.5 | 0.1 | -0.6 | -1.1 | -1.4 | -1.4 | | |

## North America remains backbone of non-OPEC growth

While OPEC's policy shift appears in part aimed at undermining North America's unconventional production, supply growth from the region is unlikely to be the main casualty of the resulting low prices. Nonetheless, US production provides much of the price response, as US LTO growth nearly grinds to a halt in 2H15 compared with 1H15. Beyond 2015, the recently announced cuts in capex as high as 50%, more of which are certain to come, will see depressed LTO growth rates through 2017. Companies unable or unwilling to cancel rig contracts, in the short term, may continue to drill wells but leave them uncompleted due to unfavourable economics, waiting for prices to rise before commencing production. The decreases in spending will also necessitate a realignment of industry activity away from marginal plays and projects to more proven areas that have lower production costs. True to its new role as the swing producer, LTO growth will start to recover in 2H17 as market tightens. Still, the growth in 2017 and 2018 will fall far short of the rate of increase seen in 2014.

A significant upside risk to the forecast remains. Although the last few months have seen a dramatic decrease in drilling rigs and drilling permits in the United States, these may not necessarily translate into a commensurate slowdown in growth due to efficiency gains and operational discipline. The experience in the US natural gas market may be a good indicator as to how the oil market may respond to the price downturn. When natural gas prices collapsed in 2009 and 2010, natural gas production continued to grow because the producers took advantage of improved efficiencies, lower production costs, and refocusing on most productive areas.

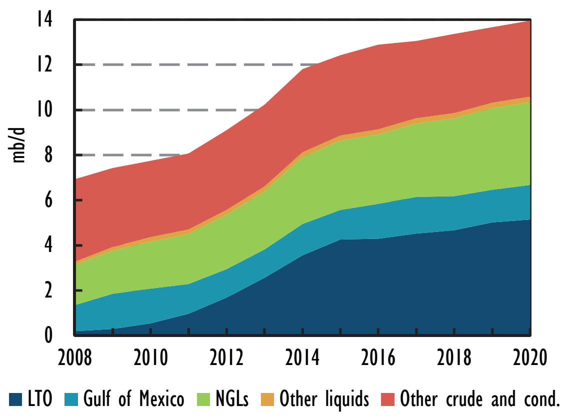
Total oil growth from the United States and Canada will slow to about 500 kb/d per year on average through 2020 compared with average growth of 1.1 mb/d in 2010-14 and North America will remain the top source of non-OPEC incremental supply for the forecast period.

Total liquids production in the **United States** is forecast to rise to almost 14 mb/d in 2020, from 11.8 mb/d in 2014, an average increase of about 360 kb/d per year. This level of liquids output sees the United States retain its top spot among non-OPEC producers and potentially continue to outpace Saudi Arabia in the medium-term. Average growth in US output through 2020 is significantly lower than the increase posted in 2014, which saw total supply rise by 1.5 mb/d, an all-time record for a non-OPEC producer, and it is lower than the more modest average growth rate of 860 kb/d posted over the previous five years.

LTO accounts for most of the total net increase in US output, rising to an average of about 5.2 mb/d in 2020, from 3.6 mb/d in 2014. Unlike conventional oil, LTO has rapid pay-back and is highly price-elastic. Its short lead time and comparatively lower upfront costs will allow it to be price responsive and act effectively as a swing producer in the event of a market upswing. Similarly, LTO is likely price-elastic on the downside, but its downside responsiveness has yet to be fully tested. Lower prices have resulted in a slowdown in LTO output growth by about 900 kb/d compared with our previous assessment. One of the significant risks facing LTO operators is their vulnerable financial position and risk to continued access to financing due to their leverage.

There are, however, a number of factors – such as a drop in production costs and increased efficiency - that may partly offset the effects of low oil prices, allowing LTO to remain the key driver behind supply growth in the medium term. Improvements in drilling efficiency, in particular, are a driver of continued growth. The productivity of wells is increasing on the back of enhanced precision on horizontal drilling and hydraulic fracturing, with many plays showing higher volumes over time. Data published by the US Energy Information Administration (EIA) shows drilling activity in United States plays is producing more oil than in the past, with the Eagle Ford play leading the pack in terms of increased productivity.

**Figure 2.12** US oil production



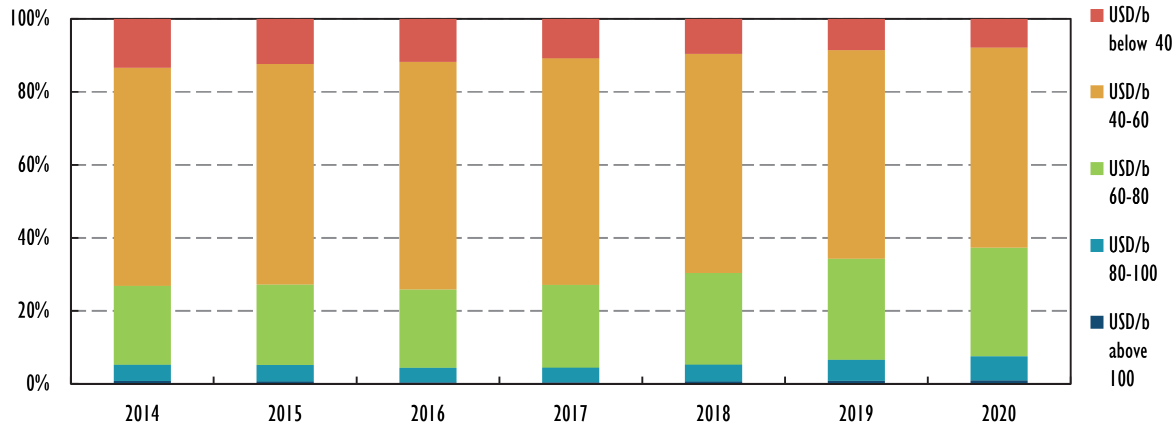

Along with Eagle Ford, the Bakken play is vital to US output growth. Large LTO producers such as Encana are looking at ways to maximise recovery from the Eagle Ford play by refracking existing wells. Prior to the recent price drops, some US producers planned to direct about 30% of their capex at marginal plays, hoping to duplicate the successes seen in Eagle Ford and the Bakken. But growth from other nonconventional areas such as the Niobrara will be limited as lower oil prices have led producers to reduce capex and refocus efforts on proven plays. Capex directed on US unconventional shale plays in the United States is expected to drop to USD 78 billion in 2015, according to IEA analysis of Rystad Energy data (published in mid-January 2015), compared to about USD 89 billion in 2014.

A slowdown in LTO production growth is evident in 2H15, with roughly 40% of rigs at risk of being taken out of service at current oil prices. This roughly translates to 640 oil-directed rigs versus the peak 1 609 that were active in mid-October 2014, as reported by Baker Hughes. However, swift technological advances could unlock yet higher flows, presenting an upside risk to the outlook. The pace of improvement in onshore drilling technology and productivity continues to surpass expectations as exploration and production companies improve drilling techniques in tight formations.

Hedging also dampens the immediate price effect on oil supply as producers use hedges as a means to protect cash flows. Smaller operators tend to use hedging more because their cash flow is dependent on fewer resources that are concentrated in one or two regions. Most oil producers have hedged at least some of their output at prices that are much higher than the prevailing crude oil price - a valuable short-term tool to offset market forces which may affect drilling and production. It does very little, however, to cushion against long term price slumps. An analysis of 2015 US-focused independent companies' hedge positions revealed that on average, they hedged roughly 36% of their 2014 production at an average price of USD 95.99/bbl. The same operators hedged roughly 25% of estimated 2015 production at an average price of USD 93.25/bbl. Similarly, E&P companies covered by Deutsche Bank US oil and gas research reportedly hedged an average of 45% of their 2015 production, further illustrating that the production sensitivity to lower prices is moderated, albeit not removed.

On average in 2014, about 48% of total US liquids production had a breakeven price of USD 50/bbl or lower, according to IEA analysis of Rystad Energy data. About 41% of US crude oil and field condensate production from tight oil and shale oil had a breakeven price of USD 50/bbl or less. The percentage of production with higher breakeven prices is expected to steadily grow through the forecast period and by 2020, about 63% of US liquids production will have a breakeven price of USD 50/bbl and above. However, breakeven prices are often higher than production costs as they account for capex, opex and government take rather than just the unit cost of extracting oil.

**Figure 2.13** Percent of US production of crude and condensate from tight and shale oil within breakeven price ranges




Source: IEA analysis of Rystad Energy data

Capital expenditures, although being curbed in 2015 and 2016, will remain roughly flat in the medium term, according to Rystad Energy data published in mid-January 2015. Capital expenditures, including exploration capex, totalled roughly USD 156 billion in 2014, rising from the 2013 level of USD 144 billion. By 2020, capex will rise again to roughly the same level as in 2014 at approximately USD 156 billion. The increase in capex past 2016 is likely due to the pursuit by companies for growth opportunities and is based on an assumption Rystad Energy included in its analysis that prices will rebound in 2016.

Oil production in the Gulf of Mexico (GOM) rose in 2014 as a number of new projects came online, including Shell's Mars B and Cardamom fields, Chevron's Jack and St Malo fields and the Tubular Bells project operated by Hess. The deepwater GOM will see other fields come online and boost total overall output to more than 1.6 mb/d by 2017 before it starts to decline. The increases in GOM production between 2015 and 2017 will be driven by a ramping up of projects that have recently come online and also from others expected to commence production in 2016 and 2017, including the Gunflint/Freedom, Heidelberg and Stones developments. Overall, roughly 500 kb/d of new production capacity is set to come online over the next two years.

Alaska's production averaged 510 kb/d in 2014 and is expected to fall to 480 kb/d in 2015, remaining roughly flat through 2017 before it declines through the end of the forecast period. The slide in Alaska's production will occur as legacy fields' declines outpace new production. Conventional production elsewhere, most notably in Texas, is also expected to rise through 2016 from the 2014 level and then to decline through the forecast period.

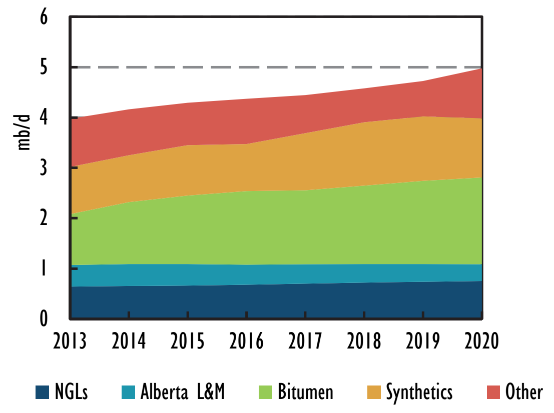
The second largest source of US supply growth comes from non-crude liquids, specifically natural gas liquids (NGLs) production. In 2020, NGLs will account for roughly one quarter of total US production. US NGL output is expected to grow by 720 kb/d to 3.7 mb/d by 2020, accounting for more than one third of global NGL supply at the end of the decade. The United States is the world's top NGL producer today and will remain so throughout the forecast period. NGL growth is driven by a number of factors, including forecast strong growth in US natural gas production, infrastructure expansions and continued demand for diluent in Canada. The pricing differentials between dry gas and liquids-rich gas provide an incentive to producers to continue targeting wet gas areas, the recent oil price plunge notwithstanding. This is particularly evident in the Eagle Ford formation, where drilling rates in the liquids-rich areas are much higher than in the dry gas areas of the play. In 2014, dry gas at the Henry Hub in Louisiana averaged USD 4.39/MMBtu, while Mount Belvieu, Texas, prices for propane and butane averaged USD 11.39/MMBtu and USD 11.86/MMBtu, respectively. By mid-January 2015, economics still favour wet gas areas, with propane prices averaging USD 5.19/MMBtu and butane at USD 6.71/MMBtu compared with the Henry Hub natural gas price of USD 3.07/MMBtu.

However, a lack of market for ethane may dampen the prospects for US NGL production. Ethane volumes produced have come against the levels that can be "rejected", or mixed into the natural gas stream. The industry is taking steps to expand infrastructure needed to cope with increasing volumes of ethane, including construction of new ethane crackers and expanded capacity of existing facilities.

**Canada's** price sensitivity differs greatly from that of the United States. Canadian oil sands, which account for most of the country's oil output growth, require comparatively high upfront capital costs and have long pay-back periods. Projects that have already been invested in will not be stopped by lower prices. Producers will instead be incentivised to maximise output in a bid to recoup investment costs. New projects, on the other hand, are unlikely to be sanctioned and will likely be delayed.

On aggregate, Canada's oil output is expected to grow steadily to just under 5 mb/d in 2020, up 810 kb/d from 2014. In-situ production of bitumen and synthetic crude will lead growth, with the former accounting for the ever-growing share of oil sands output, but a number of mined bitumen projects, including Phases II and III of Imperial's Kearl project, will also contribute. Lower prices cut the Canadian supply outlook by about 430 kb/d since last *Report*. In 2014, oil sands production accounted for more than 50% of Canada's total output and we expect that the relative proportion of bitumen will grow to about 60% by 2020.

**Figure 2.14** Canadian oil production




Oil sands projects, with long pay-back time, are on the opposite end of the price-sensitivity spectrum compared to LTO producers. Most of Canada's upstream projects have long lead times, and once cancelled or postponed, oil sands projects cannot be brought online quickly in response to increasing prices.

Natural gas liquids are forecast to grow to 750 kb/d in 2020 from 650 kb/d in 2014. The increase in NGLs comes amid an expected decline in natural gas output through 2016. Producers will continue to focus on liquids-rich Duvernay shale play in Alberta as they struggle to meet the need for diluent. Ethane production in Canada is expected to decline in 2015, but small increases are expected throughout the forecast period. Canada's ethane production will be limited by cheaper ethane produced in the United States. Although Canada's NGL growth pales in comparison to that of the United States, it will remain one of the largest NGL producers in the world.

While oil prices play a major role in Canada's production outlook, a lack of export infrastructure may also pose constraints to growth. Particularly in the case of light synthetic oil, producers will need to secure new market outlets and alternatives to shipping light crude south to the United States. These alternative options include additional capacity to ship crude to Canadian refineries on the Atlantic coast, moving it to British Columbia and possibly exporting it to Asia.

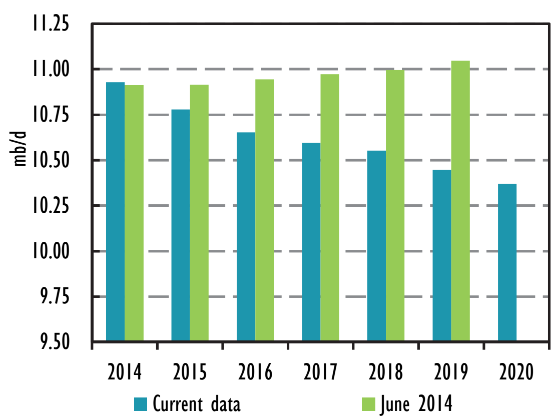
Construction of the Keystone XL pipeline, a 1 897 km crude oil pipeline connecting Alberta and Kansas, continues to be stalled, with US President Barack Obama vowing to veto legislation permitting its construction in January 2015. Canadian producers are looking at other outlets such as the Northern Gateway pipeline which will carry crude oil from Alberta's oil sands to the deepwater port of Kitimat in British Colombia, allowing the crude to be loaded onto tankers and shipped to international markets. Canada's government approved the construction of the pipeline in July 2014, subject to numerous conditions, bringing into question when the pipeline will be finally constructed. Kinder Morgan, too, is seeking to increase pipeline capacity by expanding the Trans Mountain pipeline system, which runs from Edmonton, Alberta to Vancouver, British Columbia and onto the Puget Sound area in the US state of Washington. If approved, the expansion would result in pipeline capacity of 890 kb/d, up from the current capacity of 300 kb/d.

Canadian E&P capital spending on liquids is forecast to decline in 2015 to USD 79 billion, before increasing in each of the following years through 2020, according to Rystad Energy data published in mid-January 2015. Planned investments in oil sands projects are expected to drop sharply to USD 37 billion before reaching USD 88 billion by the end of the forecast period. The drop in investments in the near term is price driven as companies cope with oil prices around USD 50 per barrel. However, Rystad Energy assumes a rebound in prices in 2016 and beyond, leading to an increase in capex.

### *Russia is the biggest casualty of the price fall*

**Russia**, the second-largest non-OPEC liquids producer, is expected to swing into contraction over the medium term due to the crushing impact of lower oil prices and Western sanctions. The low oil prices, sanctions-related restrictions on technology and financing and the declining rouble all present severe challenges to Russia's oil sector, exacerbating the overall effect of natural declines at the country's brownfields. As a result of all these factors, Russia's production is expected to decline by 560 kb/d between 2014 and 2020. This outlook is in sharp contrast to *MTOMR 2014*, which saw Russia's output grow by about 200 kb/d.

**Figure 2.15** Russian oil production




Although Western sanctions might have had only a limited impact on Russian medium-term supplies, had prices remained where they were when the measures were first implemented, in conjunction with the price declines, they will likely have a debilitating effect on Russian production capacity. Sanctions on finance will prove especially challenging in the near term as they will restrict Russia's ability to turn to capital markets to fill the gap left by the price collapse. The increase in domestic interest rates and the run on the rouble have highlighted the economic woes facing the country. Sanctions on technology will have far-reaching consequences on oil output in the latter years of our forecast as many tight oil projects have been put on hold since sanctions were imposed.

The Russian companies targeted by the sanctions include Gazprom, Lukoil and Rosneft among others, and in general, sanctions are imposed on technology and equipment for deepwater, Arctic and shale oil projects. Following the implementation of new sanctions, Total announced that it is postponing its joint venture with Lukoil for tight oil development in Western Siberia. ExxonMobil suspended its participation in a joint venture with Rosneft after drilling the University well in Kara Sea and finding potentially considerable volumes of hydrocarbons. ExxonMobil has also suspended joint work with Rosneft in the Bazhenov shale play. Russian companies will continue their activities in unconventional oil plays and the Arctic, but lack of access to the technology will severely restrict their ability to develop these resources. Development of these resources is the key driver behind the post-2020 production growth in Russia.

In late 2014, the rouble fell dramatically and in an effort to prop up the currency, Russia's central bank increased interest rates. Lack of access to western financial markets makes the current price environment even more painful. Without the ability to refinance their debt, Russian oil companies rely on government bailouts, which themselves are constrained by cash-reserve limits. Rosneft, facing high dollar-denominated debt maturities, liquidity crisis and constraints on capex, asked the Russian government for more than USD 48 billion bailout from the State Welfare Fund in late 2014. Falling far short of the request, the government issued rouble bonds worth approximately USD 10 billion in early 2015, throwing a lifeline to the cash-strapped company.

Lack of access to funds will result in lower capex, which will not only affect future production from greenfields, but will also affect maintenance at older fields, resulting in even higher decline rates in the future. According to Rystad Energy data, capex in Russia is expected to fall to USD 62 billion in 2015. Lukoil reported in late 2014 that it had reduced 2015 capex by USD 2 billion revising its drilling plans at brownfields in Western Siberia and focusing on improvements in cash flow.

Even without sanctions, Russia's upstream sector is an extremely difficult landscape to navigate. Repeated changes to the tax regime, lack of regulatory transparency and the recent restructuring and ever-present threat of takeover by the government highlight some of the factors that make planning investment decisions in Russia fraught with risk. The recent expropriation of Bashneft harkens to the days of the Yukos affair, when the company's CEO was accused of tax evasion and saw the company expropriated. Subsequently, Yukos assets were absorbed by Rosneft. Most recently, Bashneft was returned to the state following an arbitration court approval to seize the assets, which were allegedly unlawfully sold in 2000. The case may be a harbinger of changes in Russia's upstream, sending a message to other privately-owned companies such as Lukoil.

Greenfield development is highly dependent on tax breaks and other concessions by the government. In a low-price environment and with no access to necessary funds, Russian producers will put on hold big projects with long cost recovery and a number of projects that were slated to commence production in 2016 and 2017 are expected to be delayed. The project delays will have long-lasting consequences for Russia's oil production. Given the hefty declines at existing fields of about 14% in some areas, additional greenfield volumes are central to future growth.

Total liquids production is expected to fall to 10.4 mb/d in 2020 from about 10.9 mb/d in 2014. Condensate and NGL production is expected to increase, boosted by higher gas production, with NGL output reaching an average of 975 kb/d in 2020. The Western sanctions imposed since late summer 2014 do not target natural gas production directly, however, Gazprom, Russia's state-owned natural gas production company was targeted by sanctions implemented in September 2014.

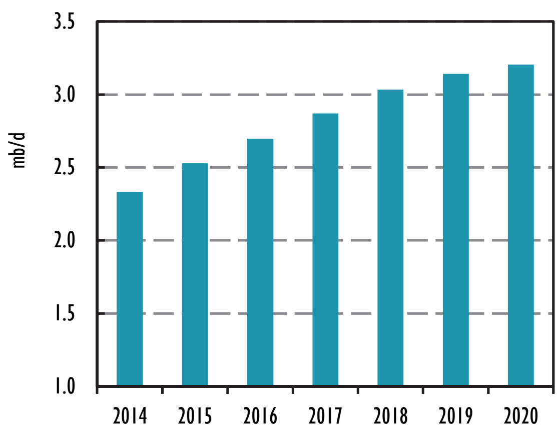
Given the western sanctions targeting tight oil production in Russia, the forecast assumes very little development in this sphere though 2018, despite continued tax breaks for tight oil deposits. The international oil companies that had teamed up with Russian majors to explore and test the commercial viability of the resources have cancelled their projects. Overall, western companies have already adopted a lower profile in Russia's upstream, with a notable exception of Schlumberger which recently bought a stake in Russia's Eurasia Drilling Company Limited. Western operators are niche players in Russia's upstream sector in terms of their equity percentage of the country's total output, with their greatest presence in Sakhalin.

### *Brazil encounters project delays, low oil prices*

**Brazil** will be the second-largest source of non-OPEC supply growth to 2020 after the US, with production rising to 3.2 mb/d. Brazil is home to the western hemisphere's biggest oil discoveries in decades, and lower oil prices are limiting the profitability of those reserves. Petrobras recently announced that it needs a minimum of USD 45 per barrel in order to produce the pre-salt fields.

Petrobras, which accounts for roughly 90% of total Brazilian production, sees both benefits and losses from the current price environment. The decrease in oil revenues is limiting the company's ability to commit funds to new developments, although the depreciation of the Brazilian real against the US dollar is offsetting the rapid decline in dollar-denominated oil revenues. The outlook for Brazil is overall slightly more positive than previous assessments solely due to baseline changes in 2014 output, which saw Brazil post impressive production results for much of 2H14. However, lower prices and legal troubles will limit Petrobras' ability to continue the growth pattern seen in 2H14.

**Figure 2.16** Brazilian oil production




Petrobras is under investigation in Brazil and the United States due to allegations of bribery and a kickback scheme. The two principal figures involved in the alleged scam are a former Petrobras director and a black-market money dealer, both of which allege that ruling politicians received 3% of all contracts in kickbacks. While the probe is underway, the company's auditor will not certify its financial statements without which it cannot have access to international debt markets, frustrating the company at least temporarily from financing its future operations.

Even before the most recent problems, Petrobras showed signs of stress mainly as a result of its indebtedness. As early as 2014, Petrobras had announced reductions in investment through 2018. While lower crude oil prices help reduce some of the burden of fuel imports, which sees Petrobras selling imported gasoline below cost, this burden has greatly contributed to the high debt levels. Although the company announced that investment plans will not change materially as a result of the lower prices, the divestment plans that the company had through 2018 may be completed at a faster-than-expected pace.

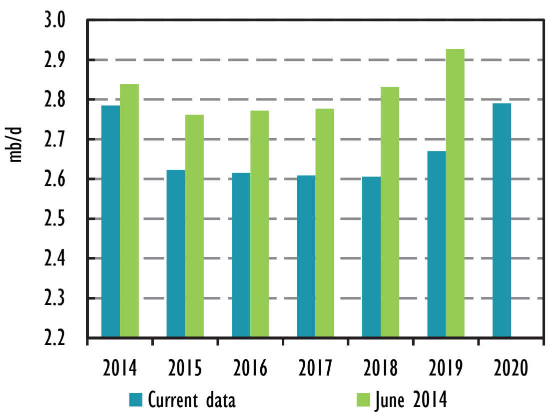
The growth in Brazil's oil production over the six years will be dominated by pre-salt fields. However, developing pre-salt fields is technically challenging and these resources require significantly more investment, time and technical ability than other deposits. With a significant rise in production costs for existing wells, equipment, labour and materials, the pressure of lower crude oil prices presents significant challenges for Petrobras to meet its growth targets.

Pre-salt fields have been successful in terms of production flows, particularly during 2014. The commencement of flows at four FPSOs during 2014 marked a turnaround in Brazil's anaemic production, but the recent successes are tenuous given the current price and legal challenges. Major contributions during the forecast period will come from the Lula, Sapinhoá and Parque das Baleias fields. In addition, the already prolific Roncador and Papa Terra fields will also contribute to growth.

### *Mexico sees marginal growth*

**Mexico's** oil sector, which is undergoing its largest transformation in decades, is seeing its prospects for growth dimming due to the price slide. Although its historic upstream reform is going ahead, the current price environment will see Mexico benefit later than previously expected. Foreign companies still see entry into the Mexican upstream of long-term strategic importance even if the assets aren't developed in the immediate future.

**Figure 2.17** Mexican oil production



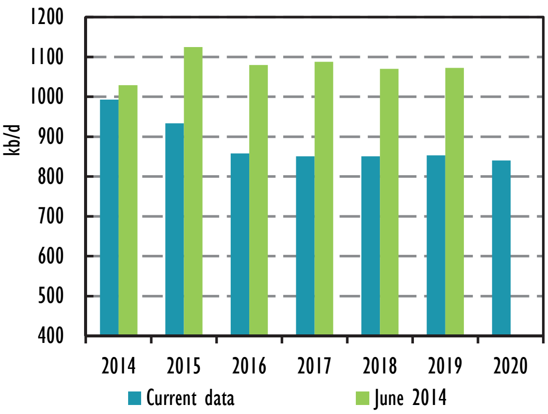

Production from Mexico's legacy fields is in severe decline and will see further decreases through 2018, when it bottoms out at 2.6 mb/d. Output starts to rise in the latter years of the forecast period. The increases will come from projects that Pemex already has in the exploration phase and that are expected to add to output after 2017, including Campeche Oriente, Chalabil, Uchukil, Comalcalco, and Cuichapa. Mexican NGL production is expected to follow the path of its crude oil and natural gas production, declining from 355 kb/d in 2014 to 350 kb/d by 2016, and then increasing to 410 kb/d in 2020 as projects benefitting from the reform process begin to bear fruit. In the context of lower oil prices, Mexico's production outlook for 2019 has been revised downward by about 260 kb/d compared with *MTOMR 2014*.

Following a feedback period by the industry, Mexico officially launched Round One in mid-December 2014 and has published the preliminary contracts for 14 shallow-water exploration blocks in the Southeastern Basin. Blocks offered are in the Salina del Istmo and Mascupana areas, all of which are on the outskirts of the acreage awarded to Pemex in Round Zero. Mexico has also released details regarding the fiscal terms of the contracts. The production sharing contracts will operate a return-based adjustment mechanism, with profit splits gradually decreasing as higher levels of internal rate of return are reached. Although the terms combine a reasonable amount of royalties and company take, low oil prices may affect the ability of companies to recuperate their costs due to royalties and low initial profit share.

According to some estimates, production costs in Mexico's shallow water fields are roughly USD 20 per barrel, and the area is fairly well explored with vast amounts of seismic data already available. This offer is the first stage of Round One, which will be awarded through the summer of 2015. Round One is focused on five areas: shallow water; heavy oil; Chicontepec and unconventional oil and gas; onshore; and deep water.

The upstream reform is wide reaching and includes the creation of regulatory structure and appropriate government agencies to regulate the sector and will foster better access to technology, finance and appropriate workforce. Tremendous capacity building will be required to let the National Hydrocarbons Commission (CNH) and the Energy Secretariat (Sener) effectively administer a more complicated hydrocarbons sector. In the medium-term, human resources may also constitute a bottleneck for the sector's development: the government estimates that over the next four years Mexico needs to train 135 000 highly specialized professionals. But given Mexico's resource base the potential for it to become a key non-OPEC producer and exporter is significant.

**Figure 2.18** Colombian oil production




**Colombia,** the third largest non-OPEC producer in Latin America after Brazil and Mexico, sees its medium-term potential eroding due to a combination of lower prices and continuing security issues in the country. Colombia's total output is forecast to fall to 840 kb/d in 2020, in contrast to last year's *Report* that forecast an output increase. The change in outlook is due to a number of factors, including the deterioration in the security situation, operational problems at mature fields and declining oil prices. Most recently, Ecopetrol, Colombia's largest producer, announced a reduction in expected production in 2015, and deep cuts to planned investment during the year. Pacific Rubiales, Colombia's largest independent producer is also reducing its upstream budget in response to low prices, with a 32% cut in planned capex for 2015.

The total oil output in 2014 averaged at slightly less than 1.0 mb/d and although Colombia has potential both in the conventional and unconventional sphere, the country has seen eroding oil production recently due to a combination of above-ground and below-ground problems. Below ground, the increased heaviness of the oil, which now accounts for about half of all output, makes it difficult to move from remote inland fields to coastal export terminals, making the country reliant on higher volumes of imported diluent (mostly naphtha) and increasing the cost of transporting the oil to the market. Above ground, a recurrence of unrest and pipeline attacks has revived concerns about political disruption risks. Although unrest is not new to Colombia and the government had in recent years managed to significantly reduce violence in the country, recent attacks have seen repeated sabotage to pipelines and killing of oil company personnel. Reduced violence as well as additional technology and pipeline capacity will be needed to sustain, let alone increase, Colombia's oil output. Although technology improvements and pipeline expansions are likely to take place, we see continued security issues and cuts in capex as the main limiting factors to Colombia's growth in the medium term.

Colombia's reserves and production are concentrated in the Llanos Basin. This basin is expected to remain the backbone of the country's output through 2020, but activity is also expected to increase in the Catatumbo and Magdalena Basins. There remains a great deal of the country that is unexplored, which could potentially begin to yield results beyond the current forecast period.

**Argentina's** oil production is relatively small, however its unlocked riches are expected to start contributing to total non-OPEC oil supply growth towards the end of the forecast period. Its resources include the world's fourth largest tight oil deposits after Russia, United States, and China, and recent technological advances make it possible to unlock them. For technical, political and other reasons, this huge potential has remained largely untapped. In 2014, Argentina's oil production averaged 620 kb/d. But the conditions for development are looking up. Argentina's congress has approved a new hydrocarbons law that aims to boost upstream investment by creating a standard framework for all oil and gas contracts in the country along with a standard royalty rate of 12% for all oil and gas production while also extending shale blocks and offshore concessions by ten years. Furthermore, it allows companies that invest at least USD 250 million over a three-year period in the country to sell 20% of their production internationally without incurring any export taxes. Production is expected to remain roughly unchanged through 2017 and then begin to increase as development in the Neuquén Basin, specifically in the Vaca Muerta shale play, begins to expand. Output is forecast to reach 750 kb/d in 2020 and growth is expected to gain momentum in the next decade.

International oil companies are looking to extend their reach in the shale play. Chevron and ExxonMobil have already partnered with YPF in Vaca Muerta, with the play producing roughly 20 kb/d of oil. Overall, US EIA estimated Argentina's shale oil potential (technically recoverable) at 27 billion barrels, mainly in the Neuquén Basin, although potential resources exist in three other basins in the country, the Golfo San Jorge, Austral and Paraná Basins.

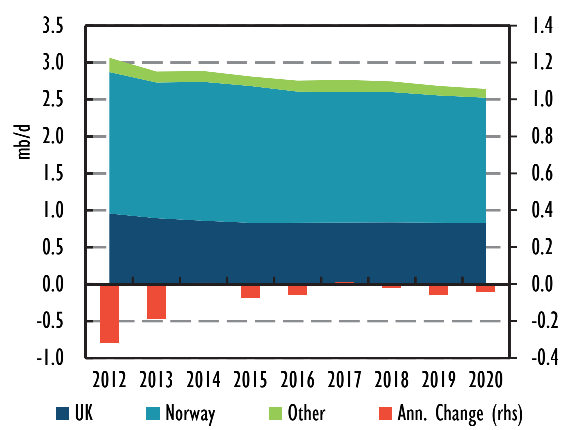
### *North Sea suffers setback*

Total North Sea production, which includes supplies from the UK, Norway, Denmark, Netherlands and Germany, is projected to be 2.6 mb/d in 2020. New project starts will partly offset reduced output from legacy fields but the recent slump in oil prices will result in project delays and therefore lower than previously anticipated production volumes in the medium term. Crude oil output from Brent, Oseberg, Forties and Ekofisk, which make up the BFOE price benchmark, is expected to decline each year through 2020 and fall to a little over 500 kb/d that year.

Arresting years of large declines, **United Kingdom** production is forecast to bottom out at 830 kb/d in 2015 and remain roughly flat throughout the forecast period. New start-ups, along with fields undergoing redevelopment efforts, offset declining production at mature fields. We expect production to average 830 kb/d in 2020.

The decreases at legacy fields will be offset by additional volumes from the West of Shetland Islands offshore area. Total and BP are undertaking new field developments but have also made sizeable investments in field redevelopments. Recently started fields, including the Huntington and Jasmine fields are already helping stem declines in the UK, as is the resumption of production at the Elgin-Franklin, Gryphon and the Penguin cluster. BP's Clair Ridge and Schiehallion projects and Statoil's Mariner field are expected to come online by the end of 2018, adding about 200 kb/d of additional volumes by the end of the forecast period.

**Figure 2.19** North Sea oil production



The UK oil sector faces major headwinds, however. Heavier-than-forecast maintenance and unplanned outages can result in a production decline, as has been the case every year since 2010. We adjust our production forecast for seasonal maintenance based on company announcements for the short-term and historical patterns in the medium term, and we also include an adjustment factor for unplanned maintenance and outages.

Although capital investment in the UK oil sector reached a record high in 2014, production did not commensurately increase. The sector continues to be burdened by high taxes which exacerbate the rising costs of exploring and developing fields in the North Sea. According to some estimates, unit operating costs increased by as much as 60% by 2014 compared with 2011.

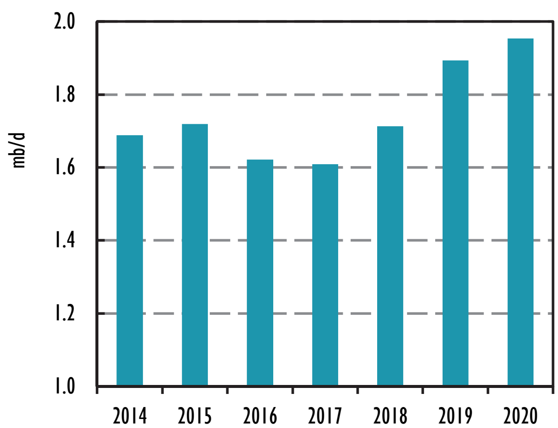
**Norway's** total production is expected to decrease slightly over the medium term as the slump in oil prices restricts capital expenditures, resulting in project delays and therefore affecting Norway's total output. The new outlook for Norway is in contrast to previous assessment, which saw its output growing over the medium term. Production overall is expected to decline in each year throughout the forecast period, averaging 1.7 mb/d in 2020. Norway's outlook turned negative due to the slump in oil prices, which will affect capital expenditures in the early years of the forecast, but which will reverberate through 2020. While Statoil's fast track development program will continue, recent announcements of cuts in capex and personnel lay-offs due to a sharp decline in revenues paints a more negative picture of Norway's outlook than previously expected.

A number of new projects will help offset declines at Norway's existing fields, including added capacity at the Norne, Ekofisk and Eldfisk fields, which will boost production by about 100 kb/d starting in late 2016. The Gina Krog and Aasta Hansteen fields are expected to come online in 2017 and produce 70 kb/d and 20 kb/d, respectively at their peaks. Development of the Johan Sverdrup field, Norway's third-largest discovery in history, is expected to bring on significant production beyond the time period of this forecast. Much of the infrastructure should be in place by the end of the forecast period, with expectations of production starting by the end of 2020.

## *Caspian growth elusive*

Total production from **Kazakhstan** is expected to increase to nearly 2 mb/d by 2020, up 260 kb/d on 2014 levels, but all of the gain will occur in the last three years of the forecast period following new delays at the giant Kashagan field. Developments at Kashagan continue to be negative: according to the operating consortium, the entire 96-kilometer long oil and gas pipelines that connect the field with the Bolashak onshore oil and gas treatment unit must be replaced at an estimated cost of USD 3 billion.

**Figure 2.20** Kazakhstan oil production



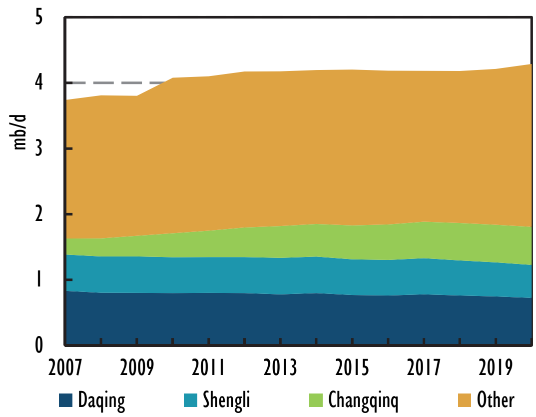

Oil from Kashagan was the main driver of Kazakhstan's expected increase in total production, but with those volumes unavailable until 4Q17, output in the country is expected initially to fall through 2017 due to declines at mature fields, including Tengiz. Total production in Kazakhstan is then expected to increase in 2018 and through to 2020 as Kashagan's production comes online, and other projects help boost total output. The Karachaganak, which produces field condensate, rather than crude oil, but also sends natural gas for processing in Russia, is expected to bring online Phase III by the end of 2019. NGL output is about 75 kb/d in Kazakhstan, but is forecast to reach 110 kb/d in 2020.

**Azerbaijan's** production will decline to 740 kb/d in 2020, a drop of 130 kb/d from the 2014 level. The Azeri-Chirag-Guneshli (ACG) field, which accounts for most of the country's total output, has seen significant drops in production, partly due to natural declines but also severe maintenance issues. We expect that ACG output will fall to about 580 kb/d by the end of the forecast period. The Azerbaijan International Oil Company (AIOC), the operator of the ACG field, is hoping to limit declines at the field through the implementation of the Chirag Oil Project and appears to have had some success in doing so. BP reported in 2014 that it has stemmed the oil production declines at the field, with the average production in the first nine months of the year roughly even with the previous year's production.

## *Asian projects already underway deliver*

Total oil output in **China** is expected to remain roughly flat through the end of the forecast period. Despite the lower base in 2014 and China's recent difficulty to increase output, medium-term production will be driven by a number of redevelopment projects, including employment of EOR techniques at the Daqing and Changqing oil fields. The Daqing oil field, China's largest, used to produce roughly 1 mb/d of oil until a few years ago, but fell to 780 kb/d in 2013. Successful use of EOR techniques and development of smaller fields in the area arrested precipitous declines. The use of horizontal drilling and hydraulic fracturing in low permeability reservoirs at the Changqing field has resulted in better performance of wells and lower decline rates.

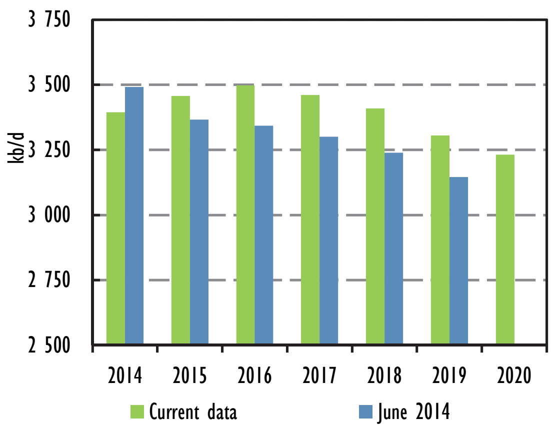
**Figure 2.21** Chinese oil production




China enjoys the world's third-largest shale oil resources at an estimated 32 billion barrels according to the US EIA, but those are technically challenging and unattractive in the current price environment. Although Chinese production is expected to benefit somewhat from the application of unconventional extraction technologies to conventional fields in the medium term, unconventional oil resources are forecast to provide only a marginal contribution in the medium term.

**Malaysia's** supply is expected to grow in the medium term, boosted by oil projects that are already underway. Total output in 2020 is seen to average 740 kb/d, approximately 80 kb/d higher than in 2014. We revised Malaysia's production outlook upwards on the back of new projects that have come online recently including the Gumusut-Kakap oil field and Kebabangan condensate field, both of which came online in late 2014. Increasing supplies from the Sabah and Sarawak areas will offset declines from legacy fields. ExxonMobil and Petronas are employing water-alternating-gas techniques at Tapis to increase oil recovery and extend the field's life and Shell is participating in two other EOR projects in the offshore Sarawak and North Sabah areas.

**Figure 2.22** Non-OECD Asia ex China oil




**Viet Nam's** output is anticipated to grow slightly through the forecast period, averaging 350 kb/d in 2020. The increases will come from new albeit small projects including the Dung Quat expansion, which will offset declines in more mature areas. Most of the projected growth is due to projects that are already in process, and therefore appear not to be sensitive to the oil price slump.

**Indonesia's** production is expected to decline to about 720 kb/d in 2020 from the average of 830 kb/d in 2014. Progress at new fields thus far has been underwhelming. The Banyu Urip field in East Java is expected to come online in 2015, and is expected to reach peak capacity of 165 kb/d by the end of the year. At its peak the filed will account for 20% of Indonesia's total production.

## *Political strife clouds outlook in Africa/Middle East*

Our overall outlook for African supply reflects the difficulties facing the oil sector, but it has been adjusted to also reflect lower prices. As a result, total African supply is expected to be lower than estimated last year. Africa's oil supply is expected to remain flat through 2016 and then slightly increase in 2017-18. Total African production is expected to average 2.2 mb/d in 2020.

With no improvement in the political and security situation in the country, **South Sudan's** output is expected to decline through the forecast period to 190 kb/d in 2020. Given the evolving conflict in the country, we no longer expect a marked improvement in the security situation and therefore see only limited investment and activity in the upstream. The possibility of a worsening conflict in the country remains and there is a significant downside risk to this forecast. **Sudan's** production outlook in the medium term has remained largely unchanged and output is expected to decline through 2020, falling to about 70 kb/d.

The outlook for **Syria** and **Yemen** continues to be dominated by political turmoil. Given the rapidly deteriorating political and security situation, the forecast for oil production remains negative over the medium term. Both countries sustained infrastructure and reservoir damage as a result of the ongoing disruptions, and even if the political situation were to improve, the return of the oil sector to pre-disruption level is unlikely in the medium term, especially given the current price environment. Syria's production is expected to fall to 20 kb/d by 2020 while Yemen's production is expected to fall to 80 kb/d in 2020 from the 2014 average of 145 kb/d. The continued strife between warring factions further exacerbates these problems, leading to a precipitous decrease in the country's production throughout the forecast period. With the recent takeover of the capital city Saana by Houthi rebels, the fall of the government and continued attacks by al Qaida, the security situation seems more unsettled than ever. The ongoing war between the Shia Houthis and Sunni al Qaida militants continues at the time of writing, with oil and gas infrastructure being directly targeted. Although the oil supply at risk in Yemen is not significant in the context of the oil market, the country's geographic proximity to neighbouring Saudi Arabia makes the recent events very troubling.

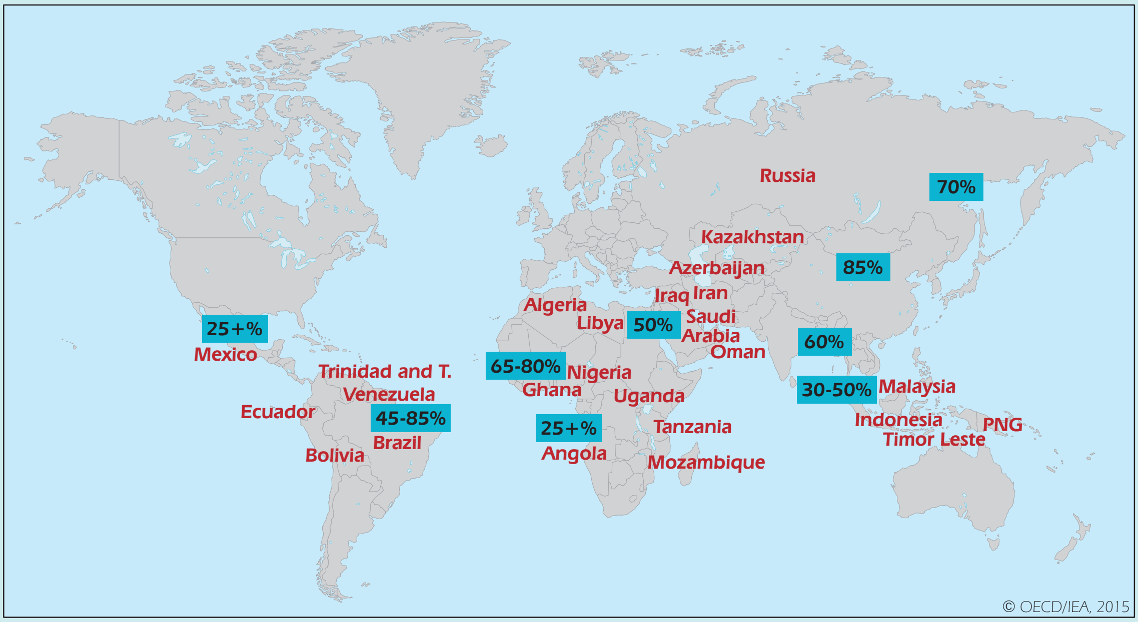
**Box 2.4** Local content requirement, another casualty of the price collapse?

Will the oil-price collapse signal a turn in the local-content policies of oil producing countries? While local-content requirements (LCR) – the legal requirement that foreign companies source part of their work force, services and/or materials in the countries where they operate – has a long history in the oil industry, their adoption by the vast majority of oil producing countries is a relatively recent phenomenon and one that has been widely blamed by international oil companies – rightly or wrongly—for cost run-ups and project delays. But as the price drops heighten competition among host countries for a limited pool of investment capital, LCR policies could become a casualty of the decline. For IOC's, the short-term cost relief that this would bring them could turn, like other cost-cutting measures, into longer-term pain.

If oil prices stay low, host-country governments will come under pressure to make their regulatory framework and oil policies more investor-friendly. LCR stand out as a policy tool that has received considerable attention in recent years but now look vulnerable to being scaled back. Many companies complain that unbridled LCR policies have driven up costs and caused major delays in oil and gas production. Yet IOCs have made few efforts to push back as ostensibly embracing ambitious LCR targets has proved increasingly essential in recent years to winning bids. The oil market selloff and the bearish turn in oil-market sentiment is calling for stricter budget discipline from IOCs, however, and makes them by necessity more selective and cautious in picking only the most profitable projects.

At the same time, oil producing countries face a shortfall in oil tax income, resulting in budget pressures. Many tax regimes expose host-country governments to production and development costs – including higher costs associated with LCR. Host governments and IOCs might therefore share a common interest in relaxing LCR policies to achieve short-term gains.

**Figure 2.23** Local content requirements around the world




This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: Willy Olsen, Intsok.

**Box 2.4** Local content requirement, another casualty of the price collapse? (continued)

Today, according to our estimates roughly 60 % of global oil production spread among 30 host countries is under regulatory regimes enforcing some sort of LCR. In practice, however, specific requirements for local content diverge considerably in both scope and implementation. Some countries have shown flexibility and developed their petroleum-sector policy targets and regulations in conjunction with industry. Others have written into the law and enforced a complex array of detailed requirements sometimes calling for local content rates in excess of 80%. LCR-enforcing countries include such important oil provinces as Brazil, Mexico and Kazakhstan. Taken in aggregate, those three countries are important contributors to non-OPEC growth in our medium-term forecast.

Mexico’s approach to LCR, within the framework of its historic energy reform, may be seen as an important test of how current market pressures, as well as the lessons learnt from past experience, may affect LCR policies in the medium term. A strong LCR standard is seen as essential for the success of the reform, which will open up Mexico’s upstream to foreign investment for the first time since the nationalisation of the sector in 1938. The proposed LCR shows that the country’s opening of its oil industry will benefit Mexico and will not amount to giving up sovereignty over its subsoil resource. Yet the target rate set by Mexico LCR policies does not exceed 35% by 2025, a relatively modest requirement.

Mexico has been examining regulatory frameworks in countries such as Brazil and Norway, which both have a history enforcing LCR with varying success. Both countries happen to have pushed through their LCR legislations in a sellers’ market characterised by tight supplies and rising prices. Most recently, Brazil imposed highly detailed requirements for various sub-expenses in E&P projects that were designed during the 2003-08 oil market rally marked by perceptions of global supply constraints, surging non-OECD demand growth and elevated prices – a period not unlike the bull market of the 1970’s, when Norway started developing the North Sea. In a well-supplied oil market and a lower pricing regime, this route might be challenging to follow for countries such as Mexico. So far, LCR has not openly come up as a point of contention between the government and prospective foreign participants, however with the changing market sentiment, the government may not be in a position to push these requirements further. We might expect the implementation to be more relaxed than when the reforms were constructed at a price level of USD 110/barrel.

Lower oil prices also affect the IOC’s own approach to LCR. Governments embrace LCR policies in the hope of achieving job creation, technology transfers and other ripple-down indirect or induced benefits for the broader economy. The petroleum industry, meanwhile, has its own sets or requirements, including complex technology, highly skilled workers and long-term capital, which create additional challenges compared with other industries. There is no one-size-fits-all type of LCR regulation that best meets both sets of objectives regardless of circumstances. Rather, optimal LCR regulations will be tailored to each country’s unique position in terms of labour markets, economic diversification regulatory framework and institutional capacity, as well as external factors such as the economic cycle, oil prices and the overall state of the oil market, Identifying “best practices” for adapting to LCR regulations across the industry is a challenge.

A trend is emerging for oil companies to take a proactive and advisory approach when dealing with governments. Many oil companies have public documents describing and outlining their engagement in creating local value. These policies recognise the mutual benefits for both companies and countries of making strategic investments in workforce and supplier development. While some public statements amount to little more than window-dressing, the industry is nevertheless increasingly aware that the development of local economies can be instrumental to the long-term success of its projects, beyond the simple requirement of being a “good citizen” to obtain licenses.

**Box 2.4** Local content requirement, another casualty of the price collapse? (continued)

If well designed, local-content policies, far from being a "cost centre", can offer economic advantages in the current price environment. Focusing on the right part of the life cycle and supply chain and developing human capital will be critical to lower costs for the medium and long term. Going forward, we are likely to see less detailed and discretionary regulatory frameworks as a way of removing some of the current bottlenecks in the industry. This will help oil companies make more strategic decisions for the long term, while also making oil production and development more sustainable in a low-price environment.

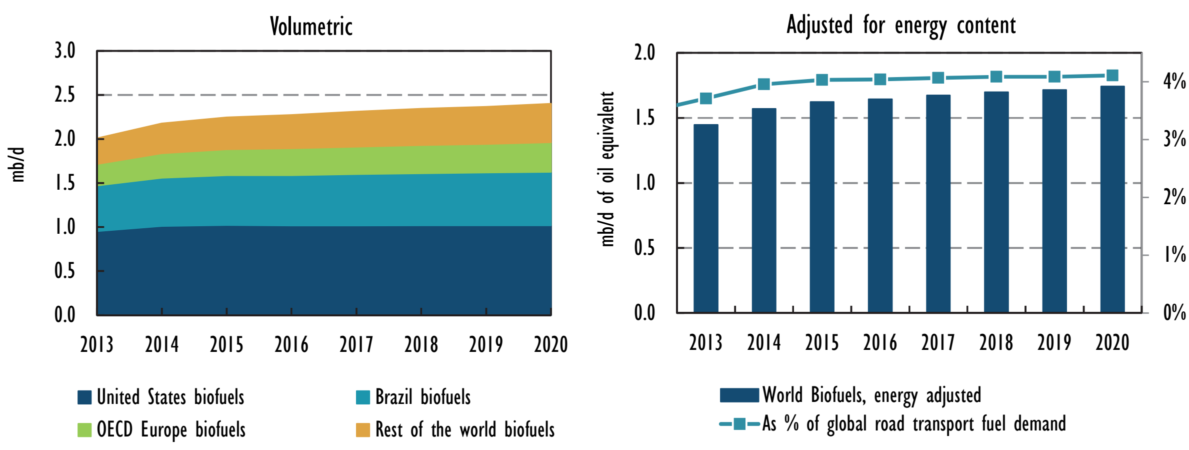
Meanwhile, ISIL appears to have strengthened its hold on Syrian territory under its control. A Western-led air campaign over ISIL-controlled territory appears to have weakened the terrorist network's vital source of fuel and funding, but it continues to be in control of the Deir Az-Zour oil region, which includes the Omar field, Syria's largest. ISIL continues to attempt to gain access to additional sources of fuel and revenue. To that end, they are targeting the country's two refineries near Banias and Homs that remain under the Assad government's control.

**Oman's** production is forecast to edge down to 880 kb/d in 2020, a fall of about 80 kb/d from the 2014 level. The decrease in production is driven by declines in mature fields, only partly offset by employment of EOR techniques, including miscible gas, steam injection and chemical EOR technologies.

## Biofuels supply

The global context for biofuels is changing little as a result of the oil price collapse, with only limited effects on production as biofuel consumption remains largely mandate-driven. Indeed, despite lower oil prices, world biofuels production is projected to rise slightly faster than previously expected, reaching 2.4 mb/d by 2020, up from roughly 2.2 mb/d in 2014.

**Figure 2.24** Global biofuels production 2013-20




With global gasoline/diesel prices plunging by nearly two-thirds since June 2014, biofuels have become less price-competitive. While this new price environment is a challenge for the industry, several factors are expected to blunt its impact on production, at least initially. First and foremost, biofuel demand is largely policy-driven. Several countries raised their biofuel blending requirements in 2014, including among others Brazil, which increased the domestic biodiesel mandate to 7% as of 2015 from 5% previously.

In addition, biofuel production costs have declined. Many key producing regions, such as the United States and the European Union, enjoyed very good harvests of biofuel feedstocks in 2014. That has brought down the price of these crops, reducing biofuel production costs. At the same time, the price of protein co-products from biofuel production, such as dried distillers grains, have risen, which has helped producers support production margins.

Higher-than-expected biofuel production in 2014 raised the baseline, from which future supplies are projected. 2014 proved to be positive for the biofuel industry worldwide, with production volumes reaching around 2.2 mb/d, up from 2.0 mb/d in 2013. Thanks to a bumper corn crop and strong demand from export markets, US ethanol production reached just under 1.0 mb/d, 30 kb/d higher than forecast in *MTOMR 2014*. Increased domestic blending mandates in Indonesia and Argentina, as well as growing demand for biodiesel imports from China and some African countries, have also supported production in those countries. The estimate of Indonesian production in 2014 has thus been revised upwards by 20 kb/d from *MTOMR 2014* and that for Argentina by 15 kb/d.

Should the current oil price regime persist for an extended period of time, the impact on the biofuels sector may become more manifest. Depending on the competitiveness of biofuels going forward, new biofuel projects may be abandoned and support policies for biofuels may come under scrutiny. For the moment, however, there are no clear signs of such developments.

### *Regional outlook*

The **United States**, the world's largest producer of fuel ethanol, is forecast to keep output of the fuel roughly steady by 2020. US ethanol production saw a 65 kb/d year-on-year increase in 2014, with total volumes reaching 930 kb/d on average, despite continued uncertainty over the Renewable Fuels Standard 2 (RFS2) 2014 volumetric target, which at the time of writing had yet to be finalised.

Production volumes were 30 kb/d higher than forecasted in *MTOMR 2014*, due to a bumper corn crop which improved ethanol production economics. Helped by this decrease in production costs, ethanol exports increased by 30% compared to 2013, to more than 50 kb/d on average.

On the back of these drivers, ethanol production is forecasted to remain roughly flat at 940 kb/d in 2015, before declining slightly to settle just above 930 kb/d over the medium-term. An important downside risk to these projections is the continued uncertainty over the design of future volumetric targets for biofuels under the RFS2.

Biodiesel production in the United States dropped to 80 kb/d in 2014, as a result of the expiration of the USD 1.01/gal blender's tax credit at the end of 2013 that was re-introduced retroactively for the year only at the end of 2014. Assuming that current RFS2 volumetric targets for biodiesel remain in place, production volumes are forecast to stabilise at 84 kb/d over the next six years, in line with the previous forecast.

In **Brazil**, the medium-term outlook for ethanol production remains bleak, with total production volumes expected to creep up only slowly, driven primarily by gasoline demand growth. Total volumes are forecast to reach 530 kb/d in 2020, up from 495 kb/d in 2014, consistent with *MTOMR 2014* projections.

Brazilian ethanol production inched upwards by 20 kb/d year-on-year in 2014, driven by continued depressed world sugar prices, leading many sugarcane mills to shift more of their output towards ethanol. Due to low profits from production of both sugar and ethanol, many mills continue to struggle to keep operations running and pay back their debts. For this reason, the industry had hoped that the regulated gasoline price would be raised following the November 2014 presidential elections. In this context the government's recently announced decision to raise taxes for contributions of intervention in the economic domain (CIDE) and for contributions to the social integration programme and social security financing (PIS and COFINS) on gasoline and diesel. The new tax levels will lead to an estimated BRL 0.20/L (USD 0.08/L) and BRL 0.15/L (USD 0.06/L) price increase for gasoline and diesel respectively and should thus help improve ethanol's competitive position.

In addition, some relief might come from an increase in the nationwide blending mandate that could be raised from 25% to 27.5% later this year. While an increase may not directly translate into an increase of total ethanol production, the higher mandate would offer producers the opportunity to sell more anhydrous ethanol, used for blending, which sells at a premium of BRL 10 to BRL 20/L (USD 0.04 to USD 0.8/L) compared to hydrous ethanol that is used unblended.

The Brazilian biodiesel outlook is more upbeat, thanks to the afore-mentioned increase in the domestic blending requirement to 7% from 5%. This should lead to a more than 15 kb/d year-on-year increase in biodiesel production in 2015, to 70 kb/d. Over the medium term, production volumes are projected to increase to 80 kb/d, driven primarily by an increase in diesel demand. This outlook is around 20 kb/d higher than in *MTOMR 2014*, which did not anticipate an increase in blending mandate at the time.

In **OECD Europe,** biodiesel production is forecast to increase to 225 kb/d in 2020 from 195 kb/d in 2014, with Germany, France and the Netherlands as key contributors, while ethanol production is seen rising to 110 kb/d from around 80 kb/d, with France and Germany remaining the largest producers.

Despite continued uncertainty over a possible limit on the contribution of food-based biofuels towards the European Union's 2020 renewable energy targets, biofuel production in OECD Europe increased by more than 35 kb/d in 2014 year-on-year. The increase was driven by a good harvest of key feedstock crops and a resulting decline in commodity prices that helped improve the competitive position of biofuels.

Some notable revisions to the previous forecast were made for biodiesel production in **Argentina** and **Indonesia**. Both countries had recently suffered from anti-dumping tariffs on exports of their products to the European Union. The subsequent drop in biodiesel output was less pronounced than forecast in *MTOMR 2014*, due to the ramping up of domestic blending mandates in both countries. In addition the biodiesel's discount over fossil diesel led to strong imports from China and some African countries. In Argentina, biodiesel production subsequently reached more than 40 kb/d, 13 kb/d higher than forecasted previously. Indonesian biodiesel output reached 50 kb/d in 2014, an upward revision of 20 kb/d compared to *MTOMR 2014*. In light of low prices for fossil diesel, biodiesel exports to China and other countries should drop this year, with negative impact on biodiesel output in both countries. Over the medium-term production volumes are nonetheless forecast somewhat higher than in *MTOMR 2014*, and will reach 65 kb/d in Argentina and 55 kb/d in Indonesia in 2020.

At the same time, policy support is burgeoning in other oil-importing economies in Southeast Asia and Africa that subsidise fuel consumption, where rising domestic biofuel production promises a valuable option to lowering fuel import bills. India, Malaysia, the Philippines as well as Thailand have all raised domestic blending mandates for biodiesel and/or ethanol in the recent year. In addition, South Africa and Zimbabwe have introduced new blending mandates aimed at reducing oil imports in these countries. While several markets are facing challenges to ramp up production volumes and enforce the new blending mandates, the general growth trend is inevitable.

### Advanced biofuels

Despite signs of progress in 2014, lack of a stable policy environment for advanced biofuels remains a major challenge for the industry, making it difficult to attract new investment. Overall, 2014 was a bright year for the advanced biofuels industry, due to the opening of five commercial-scale advanced biofuels production plants, in addition to the near-completion of a plant to open in early 2015, with a combined capacity of 9 kb/d. Three of the plants are located in the United States and two in Brazil, all of which produce cellulosic ethanol. Another large-scale plant for the production of advanced biodiesel opened in Finland. During the course of the year, several companies announced plans to open new plants in the coming years, including Raizen which announced more than USD 900 million in investment in eight new cellulosic-ethanol production units. Whether the industry's expansion plans will be realised remains to be seen, however, as several projects have been cancelled in the last years.

A positive signal was the announcement by the Italian government to introduce a blending mandate for advanced biofuels, which will increase from 1.2% of transport fuel demand in 2018 to 2.5% in 2022. Unless more countries adopt similar support policies, advanced biofuel production capacity is going to increase by around 60% to 70 kb/d in 2017. Should the recently announced plans by various companies to build new production units materialise, this figure could increase substantially. If past experience is any guide, however, it is difficult to assess to which extent the announced plans will be put in practice.

# 3. CRUDE TRADE

## Summary


- **Extending previous trends, global trade in crude oil is projected to fall by 0.3 mb/d to 33.8 mb/d in 2020 from 34.1 mb/d in 2014,** as domestic supply in North America displaces imports and more Middle Eastern oil is refined domestically.

- **The contraction in global trade is less than one third the 1.1 mb/d decline over 2013-19 presented in last year's *Report* as, according to data, crude trade decreased by 0.9 mb/d over 2013-14** and has been trending steadily downwards since peaking at 36.0 mb/d in 2012.

- **In a change to existing methodology, OPEC crude production has been allocated based on recent signals that OPEC will no longer be the 'swing supplier' and balance the market.** Accordingly, OPEC production has been allocated based on its 30 mb official production target over 2015-17 when the calculated 'call' is under this figure. This has also necessitated the inclusion of stock changes in the model.

- **Crude trade will accelerate its shift eastwards as China and Other Asia increase their imports by a combined 2.4 mb/d by 2020.**

- **Lower prices have delayed the time when non-OECD imports are set to overtake those of the OECD. Non-OECD economies are now expected to overtake the OECD in crude imports in 2020,** later than previously forecast, due to the impact of low prices on production in North America and the North Sea which has slowed OECD production growth and buttressed its import requirement.

- **As demand growth shifts to non-OECD Asia, importers there are expected to see the end of the 'Asian premium' and their buying power improve as major crude producers compete aggressively for market share.**

- **Despite the expansion of regional refinery capacity, Middle Eastern crude exports are expected to increase by 0.3 mb/d to 17.7 mb/d by 2020** as the 'call on OPEC' rises at the tail end of the forecast.

- **As trade increases between the Pacific and Atlantic basins, crude will be shipped over longer distances.** By the end of the forecast, 4.8 mb/d of Atlantic Basin crude will be exported to Asian markets, an increase of 1.2 mb/d on 2014.


## Overview and methodology

World crude markets are fragmenting, reversing an earlier period of globalisation. Inter-regional crude trade is projected to fall by 0.3 mb/d from 34.1 mb/d in 2014 to 33.8 mb/d in 2020. This forecast underlines the fact that crude oil trade has peaked, although its rate of decline is now expected to be less steep than over 2012-14, when it plummeted by 1.9 mb/d. Moreover, the contraction in global trade is less than the 1.1 mb/d over 2013-19 presented in last year's *Report* as crude trade eased by 0.9 mb/d over 2013-14.

Two key drivers are behind the fall in global trade: First and foremost, rapidly increasing production in OECD Americas has seen that region's gross imports tumble from over 9 mb/d in the mid-2000s to

4.4 mb/d in 2014 and further declines are projected to 3.6 mb/d in 2020. Secondly, crude exporters in the Middle East are expanding downstream and keeping a growing portion of their crude at home for processing, with output from their expanded and/or upgraded refineries being sent to both domestic and export markets. Additionally, recent years have seen significant refinery investment in other producing regions, notably in the FSU and to a lesser extent, Latin America, this is set to continue over the medium-term.

**Figure 3.1** Regional crude exports, yearly change

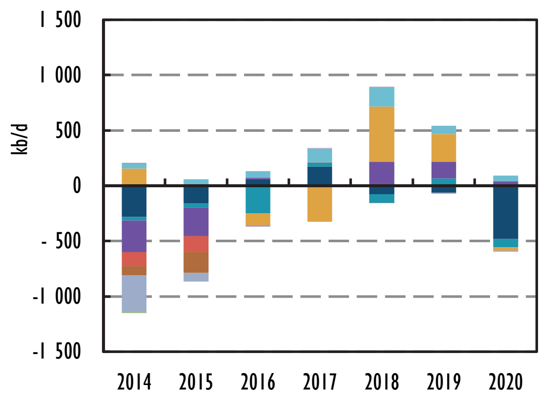
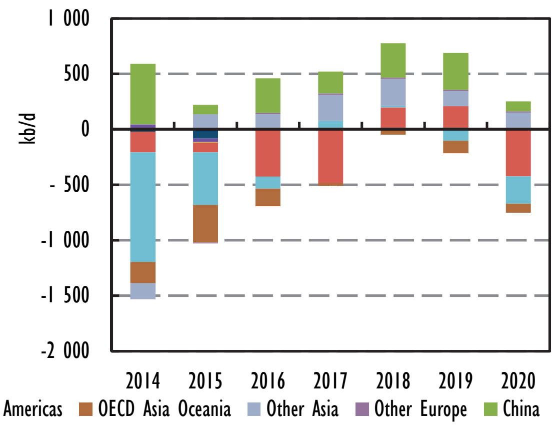



**Figure 3.2** Regional crude imports, yearly change




The fall in crude exports will not be steady but its rate of decline will slow dramatically from 2016 onwards. Since peaking at 36 mb/d in 2012, crude trade has been contracting rapidly and this trend is expected to prevail over the early part of the forecast as exports from all major producing regions ease. Subsequently, during 2016-17, crude trade is expected to bottom out at close to 33 mb/d as projected high inventories diminish the need for imported crude. It will then rebound in tandem with rising fundamentals before falling back once more as refineries are commissioned at the tail end of the forecast. This trend is more complex that that presented in last year's *Report* where the forecast was in two phases; firstly trade contracting along similar lines to this year's forecast and secondly, a steady rebound as demand for imported crudes rose.

**Figure 3.3** Inter-regional crude trade

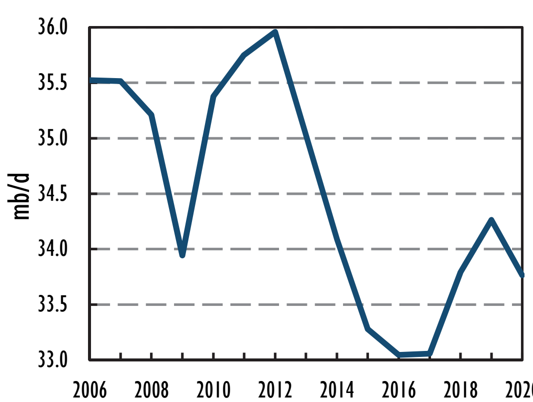
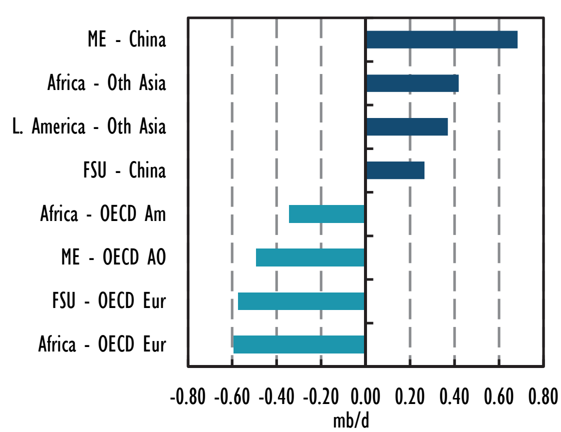


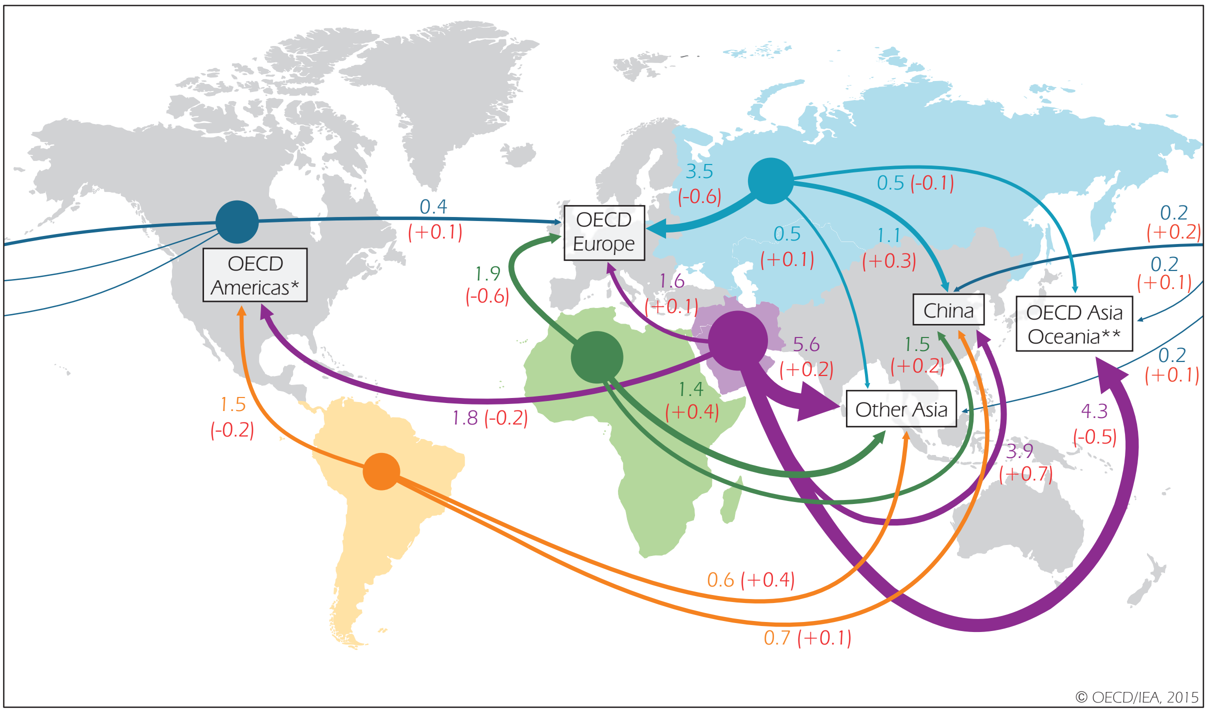

**Figure 3.4** Inter-regional export growth, 2014-20




On the import side, the beginning of the forecast will be overshadowed by the slumping import requirement of OECD Americas as US and Canadian production soars. However, during the middle of the forecast, this is expected to level off as low prices dent regional production while Europe also reduces its imports as demand contracts. In the non-OECD, Chinese imports received a boost from stock building in 2014 while imports will again rise during the middle of the forecast as refining capacity there ramps up.

Lower growth in non-OECD imports will delay the point at which the non-OECD overtakes the OECD to become the world's largest importer. A further delaying factor will come from the impact of low crude prices which has seen forecasts of crude production in North America and the North Sea downgraded compared to last year's *Report*. All told, the non-OECD is now projected to overtake the OECD in 2020 when it will account for just over 50% of global imports, a rise of 7.2 percentage points on 2014.

**Map 3.1** Crude exports in 2020 and growth in 2014-20 for key trade routes




This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: Excludes intra-regional trade.

* Includes Chile.

** Includes Israel. The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Global crude trade will continue its shift eastwards towards non-OECD Asian economies, but this will be less rapid than originally forecast as China shifts into a lower gear and orientates its economy towards serving domestic markets, a trend which has caused it to scale back its downstream investments. Nonetheless, Other Asia will overtake Europe to become the world's largest importing region by the end of the forecast as its refinery capacity swells.

Non-OECD growth will fuel an increase in trade between the Atlantic and Pacific Basins. By 2020, 4.8 mb/d of Atlantic Basin crude will be imported by Asia, an increase of 1.2 mb/d on 2014. As crude is transported over longer distances, likely on larger vessels to take advantages of economies of scale, terminals in the Caribbean, Amsterdam-Rotterdam-Antwerp area, Singapore and the Middle East will grow in importance for the building and breaking of bulk.

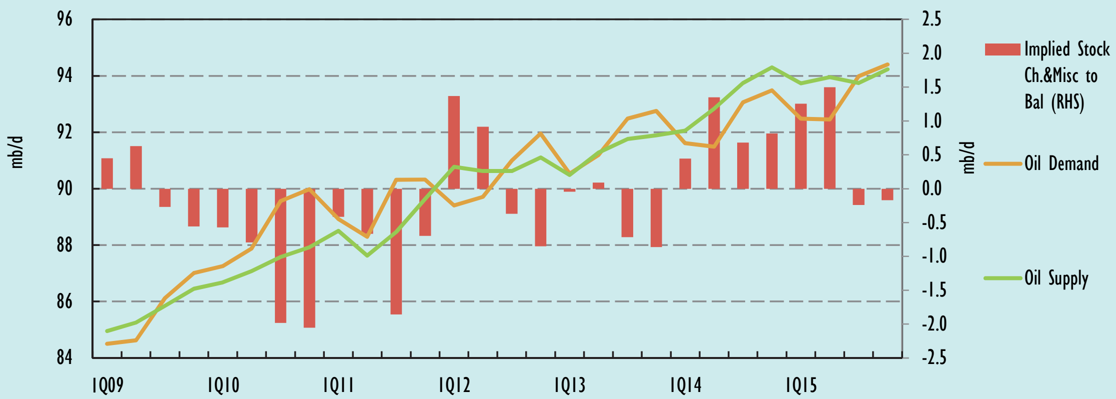
With traditional western markets in decline, competition among oil exports for Asian markets will increase. Recent OPEC policy has seen members of the group maintain relatively high production levels in the face of low prices in an apparent effort to maintain market share. Accordingly, Middle Eastern exports to non-OECD Asia are forecast to increase by a combined 0.9 mb/d while imports of competing grades, notably from Africa and Latin America will either experience lower growth or decline.

**Box 3.1** Inventory builds to buttress imports

Global imports are projected to be curbed by a significant 0.8 mb/d in 2015 compared to 2014. Although supplies to international markets will fall as a number of large Middle Eastern refineries start up while imports to North America will decrease as domestic production increases, crude imports are projected to exceed refining requirements as stock holders increase inventories.

Data indicate that, after drawing in 2013, global inventories added close to 300 mb over 2014 as global supply ran ahead of demand. Considering recent OPEC policy of maintaining production at 30.0 mb/d which is expected to be preserved into 2015 and forecast non-OPEC growth of 0.7 mb/d for the year, indications are that supply is once again expected to outstrip demand. Accordingly, a notional stock build of 210 mb worldwide is estimated for the year as a whole with the majority of the build expected to take place in 1H15. This equates to a build rate of 0.6 mb/d.

**Figure 3.5** Global demand/supply balance until 4Q15




Over the medium term, storage capacity is expected to be expanded in several import dependant regions, notably non-OECD Asia. In China, a number of new Strategic Petroleum Reserve (SPR) sites are expected to be commissioned over the forecast. With the Chinese SPR slated to hold 500 mb in 2020, there could be between 250 mb and 300 mb of capacity to be filled over the forecast. This would likely be filled as new sites are commissioned. An additional upside could come from the early-January 2015 statement from the Chinese administration that refiners would have to hold stocks equal to, or above, 15 days crude supply, beginning in 2016.

In India, new refining capacity will start up which will require new crude while it seems increasingly likely that while crude prices remain low, filling of the long-delayed SPR will commence. The first Phase 1 site is reportedly ready to receive its first oil with a further two sites scheduled to be completed in 2015, this could be a total of 40 mb of to be filled over the year. Phase 2 is scheduled to hold over 180 mb, although timescales are currently unclear, some of this capacity could be commissioned by the medium-term horizon.

Inter-regional trade has been modelled as a function of projected oil production, demand growth and refinery utilisation with incremental supplies being allocated based on expectations of refinery capacity expansion. In a change to prevailing methodology, OPEC crude production has been allocated based on recent signals that OPEC will no longer be the 'swing supplier' and balance the market. Accordingly, OPEC production over 2015-17 has been modelled above the 'call on OPEC', at its 30 mb/d official production target. Considering this, stock changes are now included in the model to account for imbalances between supply and demand over 2015-17, as was the case in 2014. The term 'crude oil' used within this chapter refers to crude oil and marketed condensate but does not include NGLs. Historical import and export data are benchmarked against official trade data for OECD countries (available in the IEA's Monthly Oil Data Service) and customs data for a number of major non-OECD producers and consumers, with the remainder of non-OECD data compiled from tanker tracking information.

## Regional developments

### *Exports from OECD Americas seen rising to 1.0 mb/d by 2020*

Despite falling by 0.8 mb/d over the forecast, OECD American imports are now expected to decline at a slower pace than previously expected. The region's imports are seen higher due to higher import requirements in North America, as regional production growth eases amid low crude prices, and more condensates are seen to be exported due to a recent easing in the export restrictions of US condensates. The reduction in imports is significantly less that the 3.7 mb/d reduction over the previous six-year period up to 2014 and reflects the increasing complexity of the region's trade flows as the US legislation on exports is clarified. Accordingly, the region will remain a significant net importer of crude as gross imports and exports are seen at 3.6 mb/d and 1.0 mb/d by the end of the forecast, respectively.

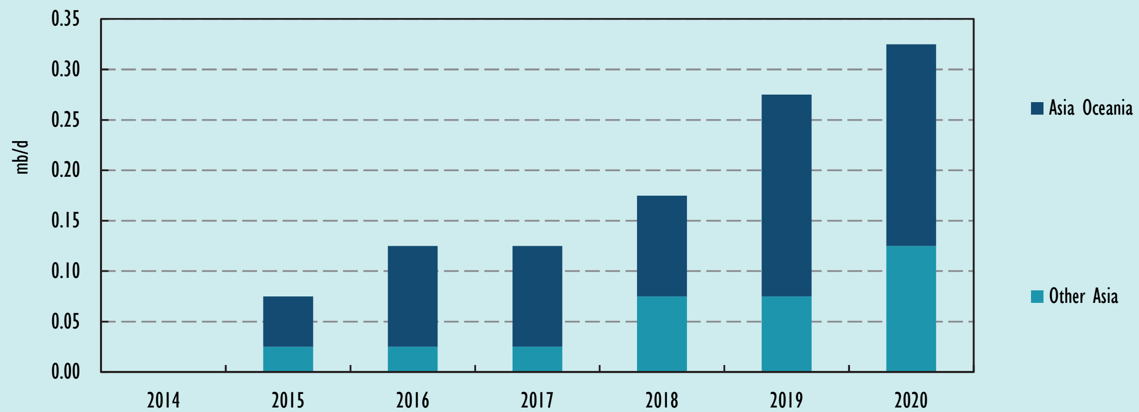
While increased availability of Canadian heavy oil in the US Gulf will displace imports of other heavy crude grades from further afield, the majority of the region's waterborne imports will nevertheless remain heavy or medium-sour grades while light grades will be 'backed out' to other markets. This will see the majority of regional imports come from Latin America and the Middle East. Imports of Latin American crudes, notably from Venezuela, will contract by 200 kb/d to 1.5 mb/d. Middle Eastern crudes will drop by 0.2 mb/d to 1.8 mb/d. Saudi Arabia is expected to remain one of the region's main suppliers given its presence as a partner in the Motiva refinery on the Gulf Coast and it will not necessarily cede its role as the regional sour crude price setter. Rather, in order to maintain its market share, Saudi Aramco could price its crudes aggressively. Recent tanker tracking information also suggests that shipments to the US West Coast have picked up which could see the Kingdom increasingly target this market to offset any loss in flows to the Gulf Coast. If Saudi Arabia preserves its market share, imports from other Middle Eastern suppliers, notably Kuwait and Iraq are expected to fall. African imports are set to be sharply curtailed to less than 50 kb/d in 2020 which would likely be arbitraged across the Atlantic when economics allow.

By the end of the forecast, the OECD Americas is expected to export 1.0 mb/d of crude. Other than US condensate, exports of Mexican Maya crude to Europe are set to continue while, as Albertan production rises, Canadian crudes are also expected to penetrate markets further afield. Apart from the United States, refineries in China, India, South East Asia and Europe already import sporadic cargoes of Canadian oil and these are set to become more frequent over the forecast period. By 2020, Asian markets are expected to import a combined 0.5 mb/d of predominantly heavy Canadian oil and US condensate, an increase of 0.4 mb/d on 2014. A final decision had yet to be made at the time of writing on either Kinder Morgan's 525 kb/d Northern Gateway or TransCanada's 890 kb/d Trans-Mountain Express pipelines to move Albertan oil to the Pacific Coast. Even if those pipeline plans are not realised, Canadian crude (including re-exports from the United States) will likely reach Pacific Basin markets by rail or ship if economics support it. Should at least one of the planned pipelines be approved and completed before the end of the forecast, however, Canadian exports could steeply increase.

**Box 3.2** US condensates heading to Asia

The regulatory framework governing US crude exports remains top of the policy agenda and is seen shaping OECD America's trade flows over the medium term. Some limited US condensate was exported in 2014 and at end-year the US Bureau of Industry and Security (BIS) clarified that condensate could be exported without license provided it was first 'processed through a distillation tower' with 'material' changes made as a result which would mean that it would then be classified as a petroleum product.

**Figure 3.6** US condensate exports




US condensate production is projected to ramp up steadily to just under 1.4 mb/d in 2020. However, only a relatively small portion of this is likely to be exported outside the region as most is expected to be processed in the US refining system and subsequently turned into finished products, or traded with Canada and Mexico, where it is either processed by refiners or used as diluent within the tar sands industry or blended into heavier streams.

Considering these constraints, US condensate exports outside the region are projected to ramp up slowly to over 300 kb/d in 2020. Most of these volumes are expected to go to OECD Asia Oceania. In Korea, which has already sporadically imported US condensate, refiners and petrochemical producers (which largely import on a term-contract basis) are being encouraged through tax incentives to diversify imports away from the Middle East. Additionally, limited supplies are seen heading to Other Asia, notably Singapore. However, these shipments may be infrequent and reliant on arbitrage economics making US supplies more competitive than competing condensates from Russia, Qatar and Australia.

Despite US legislation currently restricting most crude exports, there has been a marked increase in crude exports (including condensates) to Canada which averaged 300 kb/d in 2014 and are expected to continue. Over the medium-term, the majority of the growth in US supply is expected to be in light, sweet grades, which is not optimal for US refineries, which were built to process heavier grades. While some refiners are investing to increase their processing capabilities of light crude oils, by adding topping units and flash towers, the less than optimal crude slate is expected to encourage further swap agreements for the exchange of light US production versus heavier grades. Initially, this could see extra volumes of US crude heading north, but could be expanded to other regional producers, such as Mexico, or other exporters of heavy crudes.

## *European imports to steadily decline*

European (OECD Europe plus non-OECD Europe) imports are set to steadily decline to 8.2 mb/d in 2020. The 1.0 mb/d (-1.8% CAGR) contraction in imports results from structurally decreasing demand which is closely linked with the ongoing rationalisation of the region's refining industry. Declining North

Sea production reduces exports to a trickle. Less than 0.1 mb/d is projected to leave the region in 2020, this equates to a contraction of 14.4%, comfortably the steepest decline among major producing regions.

The FSU will continue to be the main supplier of crude processed in European refineries over the medium term, accounting for 3.9 mb/d in 2020. Nonetheless, this equates to a 0.6 mb/d fall on 2014 levels. Shipments of Middle Eastern crudes into Europe are expected to rise by 0.1 mb/d over the forecast to 1.7 mb/d by the beginning of the next decade. Meanwhile, African imports could see a steeper drop of 0.6 mb/d to 1.9 mb/d in 2020.

## *OECD Asia Oceania to diversity crude imports*

Not all Asian regions are expected to see import growth. As demand in mature, historically import-dependant economies in OECD Asia-Oceania declines by 0.3 mb/d over the forecast, leading to a further round of refinery rationalisation and lower throughputs, imports are set to fall by a steep 0.8 mb/d. Some offset to the fall in imports will be provided as increased supplies of Australian condensate, associated with the vast Gorgon LNG projects, are shipped within the region to the Korean and Japanese petrochemical industries.

Middle Eastern exports to the region are projected to contract by 0.5 mb/d to 4.3 mb/d. Nonetheless, and despite efforts of the Korean government to encourage refiners to diversify imports away from the Middle East, the region will comfortably remain Asia Oceania's main crude supplier, accounting for near-80% of total crude imports. One reason for this is that regional refiners prefer to buy crude on long-term contracts for energy security purposes. FSU crudes imported via Kozmino, the end-point of the ESPO pipeline, are expected to be curbed by 0.1 mb/d over the forecast as Russian exporters increasingly target demand growth in non-OECD Asia. The sole region which will see a growth in exports to Asia Oceania is OECD Americas, with the region increasingly seen to import US condensate over the forecast.

## *End in sight for the Asian premium?*

The swing in trade towards non-OECD Asia will accelerate throughout the forecast. Growth will be driven by rising domestic demand, itself a function of the relatively robust macroeconomic outlook, and the rapid expansion of regional refining capacity. This will see many crude exporters prioritise maintaining or increasing market share in these markets and could be the end of the 'Asian premium'. This has been underscored by recent official selling prices of Saudi crude for Asian customers, which has seen the premium for Asian customers compared to customers in Europe and the United States, narrow. By the end of the forecast, China and Other Asia are projected to import a combined 15.6 mb/d (+2.4 mb/d), accounting for 46% of global imports. This growth will see non-OECD imports surpass those of the OECD for the first time by the end of the forecast.

**China** is set to increase its imports by 1.3 mb/d (+3.3% CAGR) to 7.4 mb/d in 2020 and is projected to overtake the United States to become the world's largest importer by the end of the forecast. Despite attempts by the Chinese government to diversify crude sources over the forecast period, Middle Eastern cargoes will still account for more than 50% of Chinese imports by 2020. Although all main exporting regions will see their shipments to China increase over the forecast period, the main beneficiaries will be the Middle East (+0.7 mb/d) and the FSU (+0.3 mb/d). It is anticipated that the bulk of these supplies will be sold under long-term contracts. The main change to the makeup of imports compared to 2014 concerns new, regular shipments of heavy Canadian oil which will reach the region by 2020. Meanwhile the FSU will be the only current exporter which will see its share of Chinese demand grow (from 13% to 15%). As stated above, imports of heavy Latin American crudes will increase based on the 'oil for loans' deals struck between China and Venezuela.

**Figure 3.7** Chinese crude imports, 2014

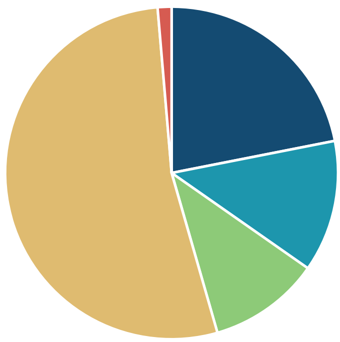
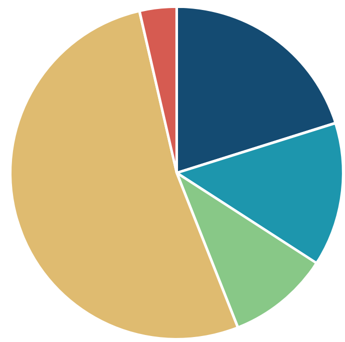


**Figure 3.8** Chinese crude imports, 2020




Crude shipments to **Other Asia** are forecast to climb by 1.0 mb/d (+2.3% CAGR) to 8.2 mb/d over 2014-20 which will see its imports exceed those of Europe by early in the next decade. This growth will be driven by three factors; rapidly expanding refining capacity, demand growth and declining domestic crude production. The region is set to become less dependent on Middle Eastern crudes as, despite imports increasing by 0.2 mb/d over the forecast, their market share will fall 7 percentage points to 69%. Meanwhile, Africa (+0.4 mb/d) and the FSU (+0.1 mb/d) will both increase shipments to the region which will see their market share increase. By the end of the forecast, small volumes of US condensate could also be imported by the region's petrochemical industry which will supplement the volumes of Canadian crude which are already making their way to the region.

## *Middle East to fight for market share, Iran a wild card*

Despite the expansion of regional refinery capacity, Middle Eastern crude exports are expected to increase by 0.3 mb/d to 17.7 mb/d by early in the next decade as the 'call on OPEC' rises at the tail end of the forecast. This will see the region's market share inch up to 52% in 2020 from 51% in 2014. This year is expected to see the start-up of Saudi Aramco's 400 kb/d Yanbu refinery and the 420 kb/d Ruwais complex in the UAE. Saudi Aramco's 400 kb/d Jizan plant and Iran's Persian Star condensate splitters are slated to begin operation later in the forecast. Despite the main aim of many of these plants being to supply expanding domestic markets, total oil (crude + refined products) shipments out of the region are expected to significantly increase by 2020 as more Middle Eastern refined products reach other markets.

Middle Eastern OPEC producers have recently signalled their intent to protect market share in Asia by reducing official selling price formulae to very competitive levels. This policy should continue through the medium term. Accordingly, Middle Eastern exports to Asia are seen rising to 13.8 mb, representing 78% of exports. In comparison, over 2014, the region shipped 13.4 mb eastwards, accounting for 77% of its exports. This growth is even more impressive considering that refiners in Korea are being incentivised to diversify away from the Middle East and that Japanese refiners are undergoing rationalisation. In view of this, Middle Eastern shipments to OECD Asia Oceania are seen declining by 0.5 mb/d to 4.3 mb/d.

A large caveat surrounds Iran. Considering that Iranian exports averaged 1.3 mb/d in 2014, 1.2 mb/d below pre-sanction levels, a breakthrough in negotiations between the P5+1 group and Iran could see sanctions ease during the forecast, which would lead to extra volumes of Iranian oil reaching international markets. Iran is likely to aggressively prioritise recapturing lost market share, especially in Europe and Other Asia, which could see it release aggressively priced extra oil onto the market. Excluding condensate, Iranian crude is generally medium or heavy sour.

Given the recent reluctance of other Middle Eastern producers to cede market share by maintaining competitive prices, extra Iranian oil on the market would likely result in an increase in Middle Eastern exports which would cut into exports from other producing regions. In Europe, Iranian crude would compete directly against Russian Urals which could see more Urals move to Pacific markets which would have knock on effects there. In Other Asia, the picture would be more complex given its diversity of crude suppliers where it would compete against similar grades from Africa (Angola), Latin America (Venezuela) and the FSU (Russia).

**Figure 3.9** Middle East export growth, 2014-20

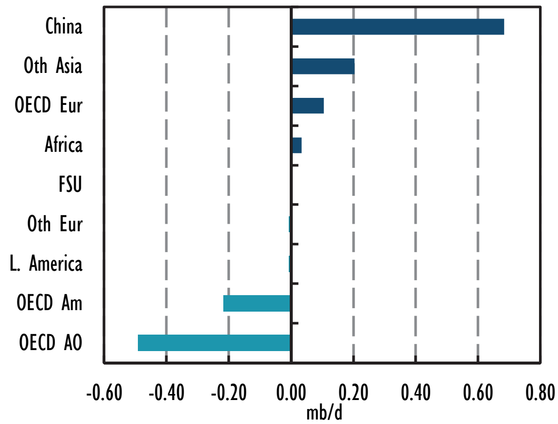
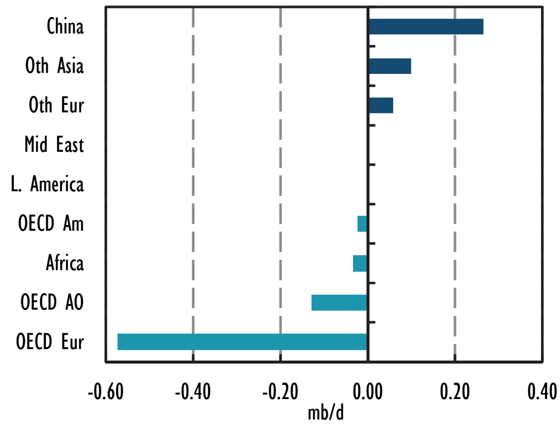



**Figure 3.10** FSU export growth, 2014-20




## *Supply constraints to curb FSU shipments*

Exports from the FSU are seen to decrease by over 0.3 mb/d to 6.1 mb/d in 2020, equating to an annual contraction of 0.9%. This is a departure from the 0.3 mb/d growth presented in last year's *Report* and is driven by the anticipated problems in Russia's upstream sector in light of lower oil prices and international sanctions and the expansion of Russia's refining capacity. However, some offset is seen by the introduction of Russia's so-called 'tax manoeuvre' which will see proportionally lower crude export duties.

With Russia's production set to decline by 0.6 mb/d over the forecast and the need to meet growing supply commitments to China, the government and key companies are expected to continue efforts to diversify exports away from traditional European markets towards Asia. After hitting a record 0.8 mb/d in 2014, Chinese imports of FSU crudes are projected to grow towards 1.1 mb/d by 2020. However, this represents a downgrade to the previous forecast where imports were set to reach 1.3 mb/d in 2019.

With its production estimated to decline over the forecast, Rosneft will have to balance its supplies to internal and export markets. Over recent years, Rosneft has increased the proportion of its crude sold under long-term contract. In its largest deal, in 2013, it agreed to supply 0.6 mb/d to China under the terms of the USD 270 billion agreement between itself and CNPC. Meanwhile, it has agreed to supply Sinopec with 200 kb/d over a ten year period. Away from China, the company has also agreed a 120 kb/d deal to supply oil shipped via Kozmino to PetroVietnam's Dung Quat refinery. Finally, in early-January 2014, the company also announced a ten-year deal to supply 200 kb/d of crude to India's Essar's Vadinar refinery. Although the specifics of what routes will be used were not included, conceivably cargoes could leave both Western and Eastern outlets. All told, total FSU exports to Other Asia are estimated at 0.5 mb/d in 2020, 0.1 mb/d higher than in 2014.

OECD Europe will remain the FSU's main market, accounting for 3.5 mb/d of crude. Nonetheless, these imports will be 0.6 mb/d lower than in 2014 (-2.5% CAGR), representing the second largest absolute decline among principal trade routes. Seaborne trade via terminals on the Baltic and Black Sea will likely be hit harder than pipeline flows. Druzhba flows are still expected to average close to 2014 levels of 1 mb/d as land-locked refineries in the Slovak Republic, Poland, Hungary and the Czech Republic, serving isolated markets, have limited alternative supply options. Since these volumes are supplied under long term 'take or pay' contracts, they are seen as a stable market for Russia.

### *African exports to be squeezed*

African exports are expected to contract by 0.5 mb/d to 5.3 mb/d in 2020. However, after initially falling sharply in 2014, as Libyan production collapsed due to the ongoing civil war, exports will then rise steadily to 5.9 mb/d in 2017 as production there recovers. African crude exports could fall again at the tail end of the forecast period, when a 500 kb/d grass roots refinery in Nigeria could be commissioned. All told, by the end of the forecast, the region will remain the world's third largest exporting region, accounting for 16% of the market.

The region's customer base is expected to change significantly with exports shifting eastwards. Exports to the OECD Americas will fall to less than 50 kb/d as imports of light and medium grades such as Nigerian Bonny are 'backed out' of the region by domestic LTO. In future, the only African crude which the OECD Americas will need will be sour. These flows of sour crudes would likely be sporadic and supported by arbitrage economics as African sour grades are pushed out of Asia by competing Middle Eastern grades. Additionally, Latin America is expected to maintain its imports of light African crudes at 0.4 mb/d which are blended with heavier regional crude.

'Backed out' light crudes will likely make their way to non-OECD Asia where they will not be in direct competition with sour Middle Eastern grades. By 2020, exports to China and Other Asia are seen at 1.5 mb/d and 1.4 mb/d, respectively, a combined increase of 0.6 mb/d on 2014 levels. That being said, OECD Europe will remain the region's largest customer in 2020 but exports will fall by 0.6 mb/d in line with contracting demand and refinery rationalisation.

### *Demand growth and refinery expansion to curb Latin American exports*

Latin American exports are expected to be characterised firstly by a period of contraction as the first phase of Petrobras' downstream expansion project ramps up. Post-2016, exports are set to steadily rebound as production rises, notably in Brazil and Colombia. By 2020, the region's exports are projected at 3.1 mb/d. Despite increasing domestic production, Latin America is still expected to import 0.7 mb/d in 2020. As with 2014, these imports will be of mainly light crudes and condensates, either used for blending with domestic heavy crudes in the region's refineries or as diluent (in the case of condensate) within Venezuela's heavy oil production.

The region's exports are also set to steadily shift eastwards to non-OECD Asia as the region's traditional market on the US Gulf Coast reduces seaborne imports as extra volumes of Canadian crude are evacuated southwards by pipelines and rail. Chinese imports of Latin American crudes are expected to hit 0.7 mb/d in 2020 based on the 'oil for loans' deals between itself and Venezuela. India is also expected to increase its imports of heavy and extra heavy crude from the region, considering that regional refiners have the complexity to efficiently process them. Other cargoes will find their way to the region courtesy of the expansion of the Panama Canal to take tankers up to Suezmax size, currently slated to be completed in 2016.

### Box 3.3 Trends in the tanker industry

**Product fleet outgrowing crude.** As product trade is projected to grow throughout the forecast (see *Refining and product supply*) crude trade is seen falling by 300 kb/d by 2020. It is not surprising that the product tanker fleet, composed by the smaller Medium-Range (MR) and Long-Range 1 (LR1) tankers is seen expanding by 24%, while the crude tanker fleet is seen to grow by 5% by the end of the forecast period, according to EA Gibson Shipbrokers. The net additions to the fleet will depend on the new deliveries and on removals, in turn depending on economic attractiveness of scrapping and whether floating storage becomes profitable.

**Figure 3.11** Product fleet yearly changes

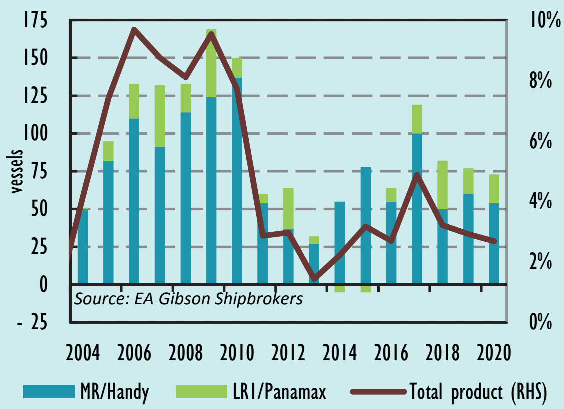



**Figure 3.12** Crude fleet yearly changes

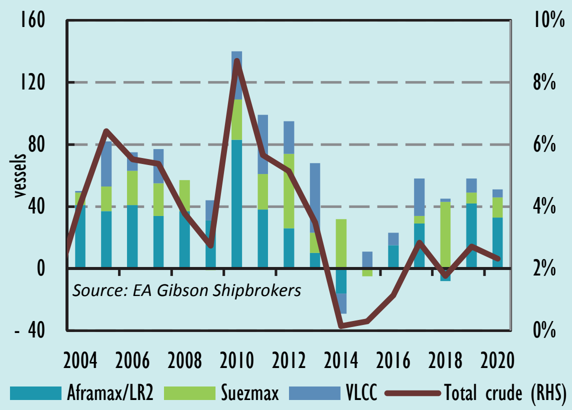



**Figure 3.13** Tanker rates and bunker prices

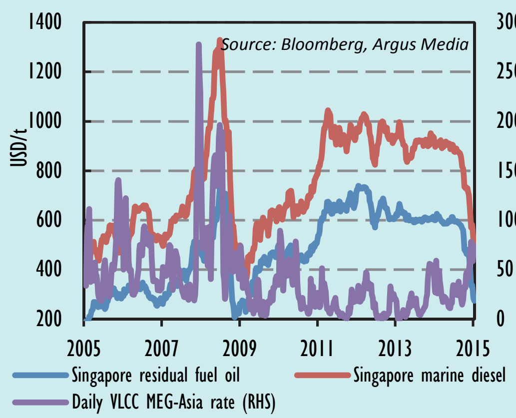
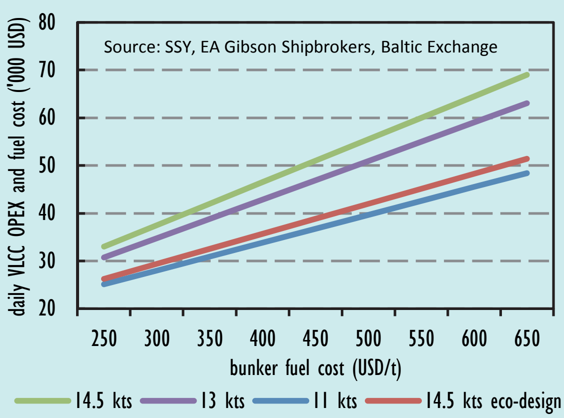



**Figure 3.14** Daily VLCC bunker and OPEX costs



**Box 3.3** Trends in the tanker industry (continued)

**Fuel saving costs.** As bunker oil prices plummeted from USD 600/t to about USD 300/t following crude oil prices' collapse, charterers are likely to see their costs significantly reduced. Residual fuel oil, the main fuel used for tankers, is the major cost component for shippers, up to 85% when on voyage, assuming other operating expenses of USD 10 500/day. Ship owners have been seeking fuel economies in the last five years as bunker prices more than doubled from their lows in early 2009. For an average laden VLCC, reducing speed from full power 14 knots to 11 knots (so-called 'ultra-slow-steaming') can halve bunker fuel consumption. It is not a surprise that charterers have been steadily decreasing their average speed in the last five years. The benchmark voyage for a VLCC, Middle East Gulf to Asia, took on average 25 days in 2014 as opposed to 21 days in the years prior to 2008. New vessel design also contributes to fuel economy, with so-called 'eco-design' vessels achieving fuel savings at higher speeds. The picture is poised to become complicated as environmental regulations increasingly require ships to use lighter fuels, such as more expensive marine gasoil (see *Sea Change in Bunker Fuels*). A stricter 0.1% cap on sulphur emissions in Emission Control Areas (ECAs) has come into force in January 2015, currently scheduled to become global in 2020.

# 4. REFINING AND PRODUCT SUPPLY

## Summary


- **Global refinery crude distillation capacity (CDU) is forecast to rise by 6.4 mb/d by 2020, to 102.1 mb/d.** Non-OECD Asia, including China, remains the main contributor to growth, adding 2.7 mb/d, followed by the Middle East with gains of 1.7 mb/d. OECD expansions centre on North America in response to rising liquids supplies. Investments in upgrading and desulphurisation capacity adds 4.4 mb/d and 3.8 mb/d, respectively.

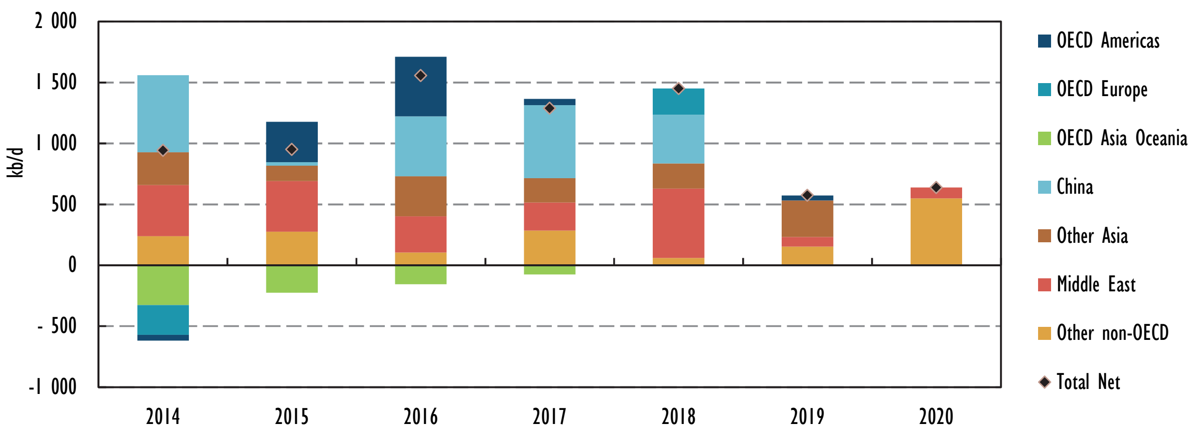
- **Surplus refining capacity is expected to rise to over 5 mb/d by 2020**, after falling to a six-year low near 3 mb/d in 2014**.** Although capacity expansions look in line with oil demand growth, in fact as much as one third of incremental demand will be met by liquids supplies bypassing the refining system.

- **Global refinery margins will come under renewed pressure from 2015 as capacity commissioned from end-2014 to 2018 exceeds demand growth.** Further consolidation in the refining industry in Europe and OECD Asia Oceania looks likely on the back of falling demand and rising import of refined products from other regions.

- **While crude oil trading has peaked, product markets continue to expand and globalise.** Trading in refined products is on track to increase rapidly to 2020, as exports out of the Americas continue apace and new Middle Eastern refineries ramp up to capacity. Europe grows increasingly dependent on middle-distillate imports, with its import requirements reaching 1.9 mb/d by 2020.

- **New emission standards for international bunker fuels, tentatively set to take effect in 2020, call for large-scale investments in upgrading capacity.** Of the various options available to the shipping industry to comply with the regulations, switching from residual fuel oil to middle-distillate is likely to be the most widely adopted.


**Figure 4.1** Global refinery additions through 2020



## Refinery capacity surplus bounces back after dip

After five years of consolidation in the refining industry, 2014 saw a slight rebound in the global capacity overhang, as crude distillation unit (CDU) additions exceeded oil demand growth by about 0.3 mb/d. Net capacity additions totalled 0.9 mb/d for the year, versus demand growth of just 0.6 mb/d. The late timing of the start-ups mitigated their impact on 2014 product markets, however. The bulk of the new builds were commissioned at end-year and were still ramping up in early 2015, allowing refinery margins to rebound from mid-year onwards.

**Figure 4.2** Simple refinery margins

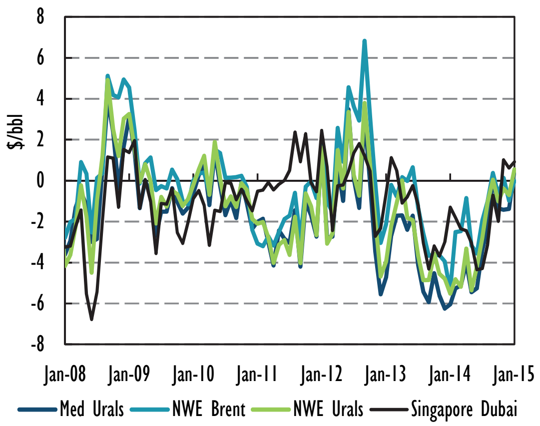
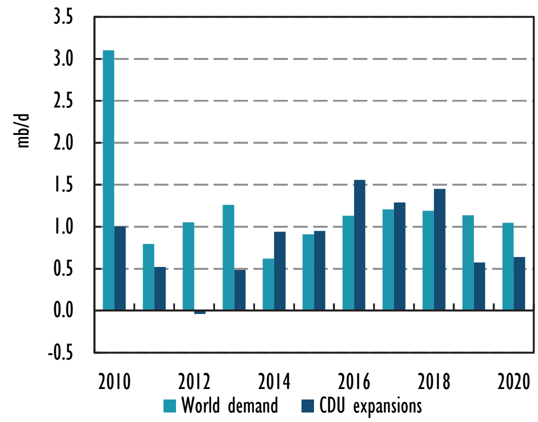



**Figure 4.3** CDU additions vs oil demand growth




Through 2020, global CDU capacity looks set to increase by another 6.4 mb/d, to 102.1 mb/d. Just under 1 mb/d of new capacity is scheduled to be completed in 2015, ramping up to an average 1.4 mb/d per annum in 2016-2018. Fewer additions are expected to be completed at the end of the decade, as current surpluses and weak demand growth have led many companies to put their plans on hold. Refinery throughputs are expected to meet two thirds of demand growth through 2020, with NGLs, biofuels, gas-to-liquids and coal-to-liquids accounting for the remainder. In the absence of further delays or project cancellations, surplus refining capacity looks set to surge from 3.2 mb/d in 2014 to 5.4 mb/d in 2017, before easing to 5.1 mb/d in 2020. Estimated surplus capacity is based on the assumption of 85% refinery utilisation rates, a level seen as generally supportive of margins. Upgrading and desulphurisation capacity looks set to add 4.4 mb/d and 3.8 mb/d, respectively.

**Table 4.1** Global crude distillation capacity (mb/d)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2020-14 |
|---|---|---|---|---|---|---|---|---|
| OECD Americas | 21.4 | 21.7 | 22.2 | 22.2 | 22.2 | 22.3 | 22.3 | 0.9 |
| OECD Europe | 14.2 | 14.2 | 14.2 | 14.2 | 14.4 | 14.4 | 14.4 | 0.2 |
| OECD Asia Oceania | 8.4 | 8.2 | 8.0 | 7.9 | 7.9 | 7.9 | 7.9 | -0.5 |
| FSU | 8.7 | 8.8 | 8.8 | 8.9 | 8.9 | 8.9 | 8.9 | 0.2 |
| China | 12.9 | 12.9 | 13.4 | 14.0 | 14.4 | 14.4 | 14.4 | 1.5 |
| Other Asia | 11.5 | 11.6 | 12.0 | 12.2 | 12.4 | 12.7 | 12.7 | 1.2 |
| Middle East | 8.7 | 9.1 | 9.4 | 9.6 | 10.2 | 10.2 | 10.3 | 1.7 |
| Other non-OECD | 9.9 | 10.1 | 10.2 | 10.4 | 10.5 | 10.6 | 11.2 | 1.3 |
| **Total** | **95.7** | **96.6** | **98.2** | **99.4** | **100.9** | **101.5** | **102.1** | **6.4** |

Note: Includes condensate splitters.

**Figure 4.4** Surplus refining capacity

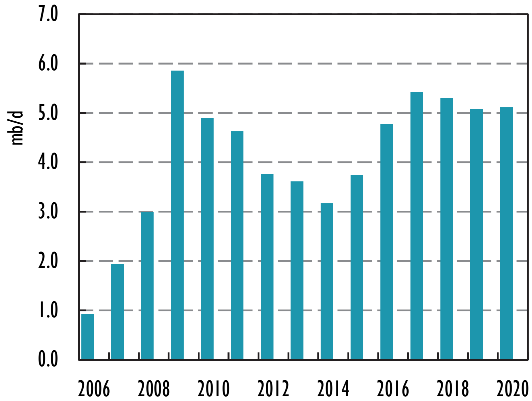
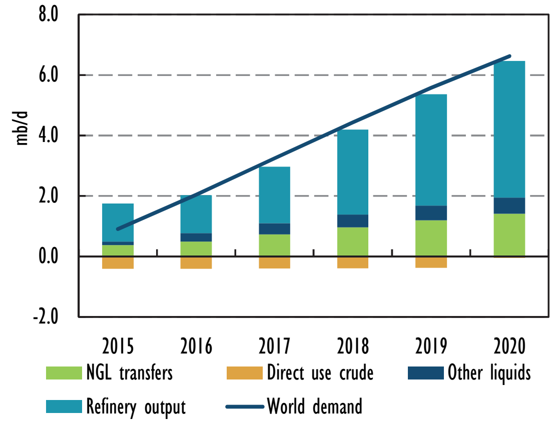


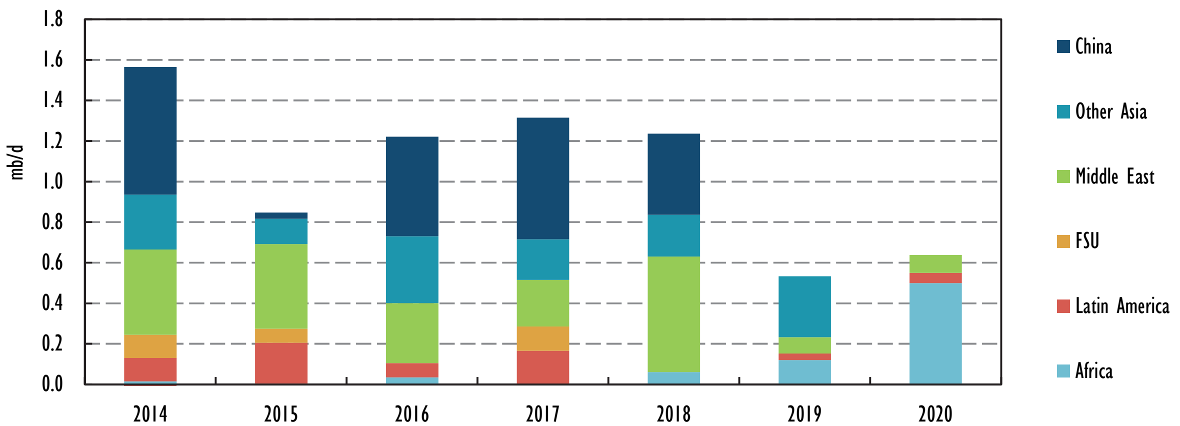

**Figure 4.5** Cumulative demand growth and sources of supply




## *Wave of new capacity coming on-stream in the non-OECD*

**Non-OECD** economies account for nearly 90% of planned net refinery capacity expansions, or 5.8 mb/d of total additions. Of this, non-OECD Asia contributes nearly half, or 2.7 mb/d, followed by the Middle East, with gains of 1.7 mb/d. In Latin America, the FSU and Africa, additions are more modest, though one mega-project in Nigeria could impact African crude and product balances significantly should it make it off the drawing board.

**Figure 4.6** Non-OECD refinery capacity additions



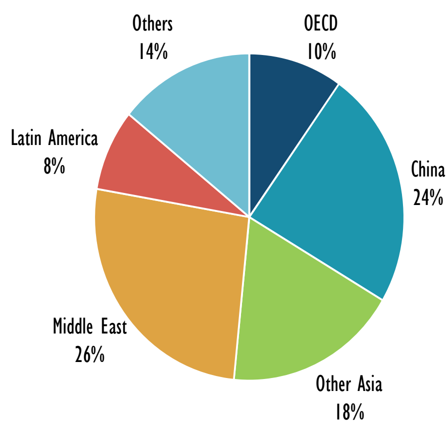

Planned additions for the coming six years follow on impressive builds in 2014. Then a total of 1.6 mb/d of new distillation capacity was added in non-OECD countries, offsetting shutdowns of nearly 1 mb/d in the OECD. Several Chinese refinery projects were commissioned early in the year, including Sinochem's 240 kb/d Quanzhou plant, PetroChina's 200 kb/d Pengzhou refinery and a 100 kb/d expansion of Sinopec's Shijiazhuang refinery. Elsewhere in non-OECD Asia, Pakistan's Byco Petroleum completed the expansion of its Karachi refinery, while Jurong Aromatics started a 110 kb/d condensate splitter in Singapore in July. Other start-ups include Yasref's 400 kb/d Yanbu refinery in Saudi Arabia and the first phase of Petrobras' Abreu e Lima refinery, both of which started trial runs at the tail-end of the year.

## *Non-OECD Asia continues to lead growth*

**Non-OECD Asia** remains the largest contributor to growth in the medium term, though projects have been significantly delayed. This is especially true of **China**, where a slowdown in domestic demand growth has helped scale back earlier, more ambitious expansion plans. Both Sinopec and PetroChina have delayed or put on hold refinery projects, trimming forecast capacity growth for the country as a whole to just 1.5 mb/d through 2020. Few projects are expected to be completed before 2016, when CNOOC is scheduled to commission a 200 kb/d expansion of its Huizhou refinery, a year behind schedule. PetroChina has also delayed the 100 kb/d expansion of its Huabei refinery by two years and will now likely only be bringing on stream its 200 kb/d Kunming refinery in 2017, two years later than originally planned. Similarly, Sinopec has pushed back completion of its 300 kb/d Zhanjiang refinery to 2017, which it is planning to build jointly with Kuwait Petroleum International, from an earlier target of 2016. PetroChina's 400 kb/d refinery in Jieyang, a joint venture project it signed with PDVSA in 2008, is expected to be completed in 2018 two years behind an earlier target. Several other projects seem to have been delayed, cancelled or put on hold for now as companies re-evaluate the market and business environment.

**Other Asian** projects have also been plagued by delays. The start-up of Indian Oil Corporation's 300 kb/d Paradip refinery, initially planned for 2013, has been postponed numerous times and is now only expected to start up in mid-2015. The completion of Nagarjuna's 120 kb/d Cuddalore project has also slipped from 2014, and is now only expected in 2016. While numerous other refinery projects are on the drawing board for India, we only include a 120 kb/d expansion of BPCL's Kochi refinery in 2018 and some smaller expansions of IOC's Panipat and Koyali plants in these projections, until other expansion plans advance further.

**Figure 4.7** Regional share of CDU expansions




Elsewhere in Asia, we expect Viet Nam's 200 kb/d Nghi Son refinery project to come on stream in 2017, followed by the 300 kb/d Rapid refinery in Malaysia in 2019. In Chinese Taipei, CPC is reportedly on track to shut its 205 kb/d Kaohsiung refinery, as planned since 1991, in response to residents' complaints about pollution from the facility. Unit shutdowns have taken place in phases since 1996, and are scheduled to be completed at the end of 2015. To compensate, the company plans to increase distillation capacity at its Talin refinery by 150 kb/d. Other projects, notably in Viet Nam and Indonesia, are advancing, but are unlikely to be completed before the turn of the decade.

## *The Middle East establishes itself as a major downstream player*

While the largest refinery capacity increments in coming years take place in Asia, the **Middle East** sees the highest rate of growth. After adding close to 1 mb/d of processing capacity over 2013 and 2014, the region is set to add another 1.7 mb/d by 2020, raising regional crude processing capacity by nearly 40%, to 10.3 mb/d, in just a decade. Yasref's 400 kb/d Yanbu refinery in Saudi Arabia started trial runs in September 2014, with its first product cargoes exported in January this year. The UAE is also reportedly on track to start up its new 420 kb/d Ruwais refinery in early 2015, and Saudi Aramco will complete its third 400 kb/d greenfield refinery at Jizan before the end of the decade. The latter project has reportedly faced delays due to project modifications and as related port and power construction fell behind schedule, but we expect the plant to be commissioned by 2018.

Despite ambitious plans to increase downstream investments and build several grassroots plants in Iraq, it now looks unlikely that any project will be commissioned before 2020. In contrast, Kuwait's downstream plans are moving forward. These include the Clean Fuels project which aims at integrating the country's two largest refineries, the Mina Abdullah and Mina Al-Ahmadi plants, and raising their combined distillation capacity to 800 kb/d, from 735 kb/d currently. The project has been delayed by politics in the past, but now seems to have gained traction, with several key contracts awarded. It is now expected to be completed by late-2018 and reach full capacity in early 2019. The plan also calls for the 186 kb/d Shuaiba refinery to be shut and converted into a terminal, and Kuwait National Petroleum Company (KNPC) is moving ahead with its ambitious 615 kb/d Al-Zour grass roots refinery, though both projects are expected to only be completed after 2020. In Iran, the 360 kb/d Persian Gulf Star refinery at Bandar Abbas is reportedly nearing completion and the first phase is expected to be commissioned in 2017, significantly increasing the country's gasoline and diesel output. Once the three phases of the project are completed, Iran could become a net gasoline exporter. According to JODI data, Iran had already reduced its gasoline imports to an average of 25 kb/d in 2014, from as much as 175 kb/d in 2006.

### *Modest growth expected in the non-OECD Americas*

In **Latin America**, only 520 kb/d of new distillation capacity is expected to be added in the 2015-20 period. In Brazil, the first phase of Petrobras' ambitious downstream expansion programme was finally completed at end-2014, when the company started the first of two 115 kb/d crude units at its Abreu e Lima refinery. The second crude tower and an upgrading unit are expected in mid-2015. The company is targeting to start its 165 kb/d Comperj project in 2017. Two proposed mega-refineries in the northern part of the country, Premium 1 and Premium 2, and a second phase of Comperj have been delayed indefinitely. Petrobras has been plagued by downstream losses, cost overruns, cash constraints, massive debt and a corruption investigation, forcing it to scale back expansion plans.

Outside of Brazil, only Colombia is expected to materially increase its downstream capacity over the forecast period with two projects. The first is an expansion of Ecopetrol's Reficar refinery in Cartagena to 165 kb/d from 80 kb/d currently. The project, to be completed in 2015, will also increase the plant's complexity and lift its light-product yields, allowing it to process heavy domestic crudes. Ecopetrol's second project is to upgrade its Barrancabermeja refinery. The project, completion of which has been delayed from 2018 to 2020, will also raise the heavy crude feed and boost output of middle distillates and gasoline, though overall distillation capacity will remain unchanged.

### *African downstream to enter the major league?*

A big question mark hangs over the **African** downstream landscape. Despite being a large crude producer, Africa suffers from inadequate refining capacity and currently imports a substantial share of its petroleum products. The continent's biggest producer, Nigeria, depends on imports for most of its refined oil product requirements. Mismanaged for years, the country's state-owned refineries work at a fraction of installed capacity, and despite numerous proposals, no new refinery project has been able to get off the ground to supply the domestic market. As a result, product imports have been surging – but this could be about to change.

Nigerian billionaire businessman Aliko Dangote is reportedly moving ahead with an ambitious greenfield refinery and petrochemical project modelled after India's giant Reliance complex, the largest in the world. An EPCM contract has been signed with Engineers India Ltd for the 500 kb/d refinery and petrochemical project to be built in Lekki Free Trade Zone near Lagos, and nearly two-thirds of the initial foreign currency requirement needed has been raised. Dangote recently increased the target size of the refinery from an initial 400 kb/d, fast-tracked its projected completion to 36 months, and in late December said that he would increase his investment by USD 2 billion, to USD 11 billion, to double polypropylene production capacity and add polyethylene capacity. Despite the project's stated completion target of 2017/2018, commissioning looks unlikely before 2020 as numerous obstacles remain, ranging from Nigeria's troubled economic situation and currency fluctuations to uncertainty about the outcome of its upcoming presidential election, planned oil-subsidy reform and long-stalled Petroleum Industry Bill. Nigeria-based sea piracy is also a concern.

Sonangol's planned refinery project in Angola meanwhile seems to have slipped from its original targeted completion date of 2017 and we now expect the 120 kb/d project to be finished in 2019. Construction is expected to start in 2015, following a USD 2 billion credit agreement signed by Sonangol and China Development Bank in December 2014. Uganda's planned refinery project is also moving forward and we expect the first phase, of 30 kb/d, to be completed in late 2018. In contrast, Senegal and Kenya's refineries were idled in 2014 due to poor economics and financing problems restricting crude purchases.

### *Russian tax law signed into law: delay sees runs maintained in near term*

FSU investments continue to be focused on upgrading and desulphurisation rather than expansions, in a bid to produce higher-value products. Almost no crude distillation capacity is expected to be added through 2020, while 980 kb/d of upgrading and 420 kb/d of desulphurisation units are planned. The investments follow Russian tax changes first outlined in October 2011, spurred by domestic gasoline shortages after years of underinvestment in refinery modernisations and upgrades. Russian refineries are among the least complex in the world, with output of low-value fuel oil accounting for roughly 30% of total product supplies.

After much delay, Russian President Vladimir Putin signed into law the proposed amendments to Russian oil tax laws in November 2014. The changes to the law, known as the "tax manoeuvre", came into effect at the start of 2015, reducing crude oil export duties while increasing the mineral extraction tax from current levels. They will also align export duties for fuel oil with those of crude oil (currently fuel oil export duties are set at 66% of crude export duties) by 2017. Export duties for diesel and other light products will be kept at 63% of those for crude, however, thus providing an incentive for refiners to maximise light–product output and exports. At the same time, the changes to the law will make simple refineries - those with high fuel oil yields - less profitable, thus forcing throughput cuts at those plants.

Since the changes were announced, the Russian refining industry set out on a massive spending programme. According to the Russian Ministry of Energy, as much as USD 55 billion were planned in 130 new units to increase the plants' light-product yields and improve the quality of their products. While several units have already been commissioned, including hydrocrackers at Surgut's Kirishi, Alliance Oil's Khabarovsk and Taneko's Nizhnekamsk refineries, it has become apparent that the upgrading plans have fallen behind targets. As such, the government revised its initial timeline, from full fuel oil-crude parity in export duties as of 1 January 2015, to a gradual increase in fuel oil duties towards 2017. Current sanctions imposed on Russia by the European Union and the United States might cause further delays as financing problems could postpone project completions.

## More OECD closures in the cards

Since the 2008 financial downturn, OECD refiners have shut 4.8 mb/d of crude distillation capacity. Of this, slightly over 2 mb/d has taken place in Europe, reducing that region's capacity to 14.2 mb/d at end-2014. Asia Oceania has cut 1.3 mb/d, while North America has shed nearly 1.5 mb/d. Expansions at other plants have provided a partial offset, however, leaving net OECD capacity reduction from 2007 to 2014 at 2.6 mb/d.

**Figure 4.8** OECD refinery closures

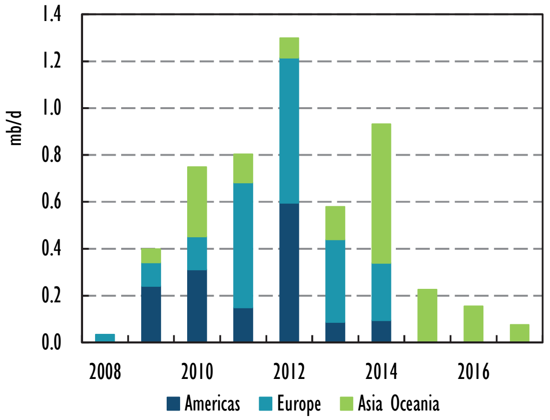
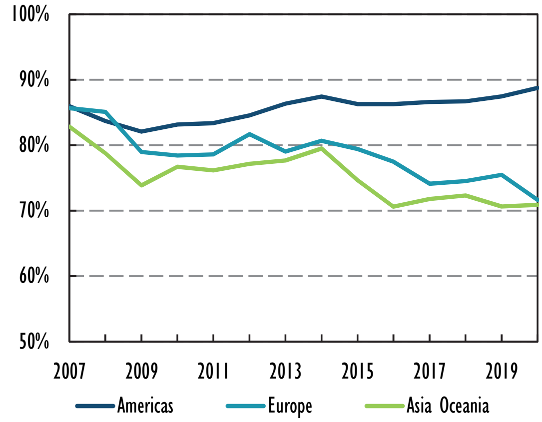



**Figure 4.9** OECD refinery utilisation rates




Over the same period, OECD refiners curbed throughputs by 2.8 mb/d in total, thus lifting utilisation rates from their 2009 lows. European refineries have taken the brunt of the cuts, curbing runs by 2.1 mb/d from 2007 to 2014. After an initial decline in activity in 2008 and 2009, North American refineries raised throughputs in line with booming regional supplies. In the Asia Oceania region, while crude runs plunged by nearly 0.8 mb/d over the period, refinery capacity additions (in particular condensate splitting units in Korea) mitigated refinery closures, resulting in lower utilisation rates overall. Looking ahead, few new refinery shutdowns have been announced outside of Asia Oceania. Further downward pressure on European refiners looks likely, after a respite at the end of 2014, when completed shutdowns briefly lifted margins. For the Americas, the question of shutdowns and capacity additions hinges to some extent upon the direction of US export policy.

## OECD Americas: surging LTO, condensate supply drive expansion

The OECD Americas look set to add 0.9 mb/d of new refining capacity through 2020, of which 90% is accounted for by US expansions in the next two years. Following years of investments in heavy crude oil upgrading units, refiners are now spending capex on projects that will help absorb rapidly increasing supplies of very light feedstocks such as LTO and condensates, mostly restricted from global markets due to legislative and infrastructure constraints.

Several condensate-splitting and topping unit projects are already underway in the US. In 2015, 330 kb/d of new capacity is poised to be commissioned, followed by another 450 kb/d in 2016. Midstream companies Kinder Morgan, Castleton Commodities, Magellan and Martin Midstream are all planning condensate splitters. Marathon is adding condensate splitters at its Canton and Catlettsburg refineries, and expanding crude processing capacity at its Robinson refinery. Valero plans to add topping units at its Houston and Corpus Christi refineries, of 90 kb/d and 70 kb/d capacity, respectively, and expand the crude distillation capacity by 25 kb/d at its McKee plant, enabling them to process Eagle Ford-type crude. Dakota Prairie is currently constructing a small hydroskimming refinery in Dickinson, North Dakota, the first new refinery to be built in the United States in over 30 years. Calumet, meanwhile, is adding capacity at Great Falls, Montana and Trenton, New Jersey. Other refiners, like Delek, are adding pre-flash towers to change their feedstock slate. A pre-flash tower removes some naphtha and light ends from the crude oil or condensate stream before it is processed in the distillation tower, and thus increases the capacity of crude the plant can process.

Those refinery capacity additions pale in comparison with expected supply growth, however. Despite cuts in upstream investment due to lower oil prices, regional liquids supply is expected to grow by another 3 mb/d by 2020, which the system will struggle to absorb. A record burst of new supplies already bumped against capacity limits in 2014. Roughly one third of new supplies will consist in natural gas liquids, however, which will mostly be fractionated and processed outside the refinery system. Regional net crude oil imports are expected to fall to 3.2 mb/d in 2020 from an average 4.5 mb/d in 2014. Recent clarifications by the US Department of Commerce (see Box 3.2, *US condensates heading to Asia)* may lead to higher condensate exports, but the amount that will be taken up by international markets is still uncertain.

Assuming no wider removal of the US crude export ban, increasing volumes of LTO are expected to be exported through swap agreements with heavier crude oil producers and further refinery projects could be proposed in coming years. Exxon Mobil is reportedly considering expanding its 345 kb/d Beaumont refinery, possibly to as much as 800 kb/d by the end of this decade, which would make it the largest in the United States. A deal to reopen the shuttered 500 kb/d St Croix refinery, meanwhile, collapsed last December after US Virgin Islands legislators rejected a proposed operating agreement between the territorial government and Atlantic Basin Refining (ABR), a company formed expressly to purchase the plant from its current owners Hess and PDVSA for USD 1.6 billion. ABR, had said in November that it intended to reopen the refinery at the end of 2016 after reconfiguring it to process 300 kb/d of light, sweet US crude.

Other refinery investments have been made to reduce the looming gasoline surplus and boost distillate output. Valero shut a 38 kb/d gasoline producing FCC and alkylation unit in October 2014, while expanding the plant's hydrocracking capacity to raise diesel production. Marathon is also considering shutting an FCC unit at its Galveston Bay plant. Tesoro plans to permanently shut a 36 kb/d FCC at its Wilmington refinery by early 2017, when it integrates the plant with the nearby Carson refinery, which it acquired from BP in 2013.

### *European refiners invest to survive*

Despite a late-2014 recovery in activity and margins, the European refining industry remains under pressure from sliding demand, a growing mismatch between refinery output and demand and growing competition from export-geared refineries in the Middle East, Russia, the United States and India. Just over 2 mb/d of refinery capacity has been permanently shuttered since 2008, largely in line with the decline in regional demand and throughputs over the same period. In 2014, Murphy's Milford Haven refinery in the United Kingdom became the latest casualty of the restructuring, after a deal to sell it to

Klesch Group fell through. Eni also announced in August 2014 that it would target a 50% reduction in its refinery capacity from 2012 levels, with its Gela, Livorno and Taranto plants expected to be shut. Gela, which has been idled since 2012, is being converted into a “Bio Refinery” in 2016. France’s Total has also announced it is considering further capacity reductions. The company’s earlier pledge not to shut any further refineries in France for at least five years has lapsed, but no firm plans have been announced.

While some plants are slated to be shut down, in other cases market participants are responding to growing competitive pressures by doubling down on their investments. Exxon Mobil and Total both announced in 2014 large investments at their Belgian refineries. Total will invest EUR 1 billion to modernise its 338 kb/d Antwerp plant, adding a solvent de-asphalting unit and a mild hydrocracker by 2016. Similarly, Exxon announced it will spend more than USD 1 billion in its Antwerp plant, to build a new coker to convert heavy oil into diesel and marine fuel. The company also plans to install a new processing unit at its Slagen refinery in Norway to enable production of high quality vacuum gas oil, a higher-yield feedstock used to create finished products such as diesel. The new residual flash tower is an upgrading unit that will improve the facility’s overall crude distillation process by replacing production of heavy fuel oil with lighter, higher-value gas oil. In Finland, Neste is spending EUR 500 million to integrate its two refineries in a bid to make them more efficient and cut their fuel oil output by nearly 25% by 2017. Kuwait Petroleum International, meanwhile, cancelled a planned USD 1.4 billion investment at its Rotterdam refinery, due to the poor outlook for the European downstream industry.

Turkey is a special case. Unlike the rest of Europe, its population is rapidly growing and its domestic demand is on the rise. The country will see the start-up of the continent’s sole new refinery, a 200 kb/d grassroots plant built by Azerbaijan’s Socar in Aliaga, to be completed in 2018. Turkey’s Tupras is also nearing completion of a USD 3 billion upgrade of its Izmit refinery. The residuum upgrade project (RUP), which was launched in 2011, aims to enhance the 220 kb/d plant's conversion capacity and allow it to process heavier and higher-sulphur crudes.

### *OECD Asia refinery consolidation continues apace*

OECD Asia Oceania is expected to continue on its consolidation path in coming years. Over the past six years, the region has shed a total of 1.3 mb/d of capacity, of which nearly half took place in 2014, when Japan completed the first phase of Ministry of Energy Trade and Industry (METI)’s so-called Refining Ordinance. The Ordinance required refiners to meet a cracking–unit-to-CDU ratio of 13%, in effect forcing a reduction in crude distillation capacity. As METI forecasts further demand declines in the medium term, it has announced a phase II of the Ordinance, requiring refining companies to shed another 400 kb/d of distillation capacity by March 2017. As opposed to phase I, phase II is aimed at encouraging synergies between refineries to boost the overall cracking ratio. Such integration has been proposed between Cosmo and Tonen General’s Chiba refineries. Australia is also on track to further curb its capacity. BP’s plans to shutter its 102 kb/d Bulwer Island refinery in 2016 will reduce the number of operating refineries in Australia to four, from eight at the start of the decade. Shell already shut its Clyde refinery in 2012 and Caltex followed suit with its Kurnell plant in 2014.

On the other hand, Korea is expanding its condensate-splitting capacity. SK Corp and a Samsung – Total joint venture each commissioned new condensate splitters in mid-2014, with capacities of 100 kb/d and 145 kb/d, respectively. Some US condensates have already found their way to Korea for processing, with more likely to come. Korean refiners are encouraged to diversify feedstock sources away from the Middle East, through tax breaks and duty exemptions, which mitigate higher transport costs. Under a law implemented in 2013, Korea will refund 90% of the freight charge difference with

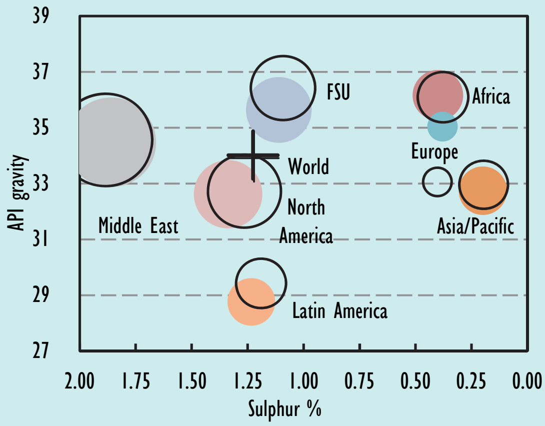
Middle East suppliers if annual imports by a company reach 2 million barrels a year. Korean refiners started importing North Sea crudes in 2011, when a free trade agreement between Europe and Korea was signed, removing import duties on crude oil from Europe, while a tax loophole allowed refiners to claim a rebate on the 3% crude import tax, regardless of whether the levy was actually paid. While the tax loophole has been closed, Korea imported an average 70 kb/d of North Sea crude in 2014, down from a peak of 110 kb/d in 2012.

### Box 4.1 Refinery feedstock quality: a light squeeze

**Average is not medium.** Refiners will see their feedstock of heavy and light crudes to grow by about 2.5 mb/d together, with medium grades gaining just under 500 kb/d by 2020. Overall, global feedstocks are forecast to become marginally lighter, by 0.11° API to 34.0°. Average sulphur content is forecast to remain virtually unchanged, inching down from 1.19% to 1.18% globally.

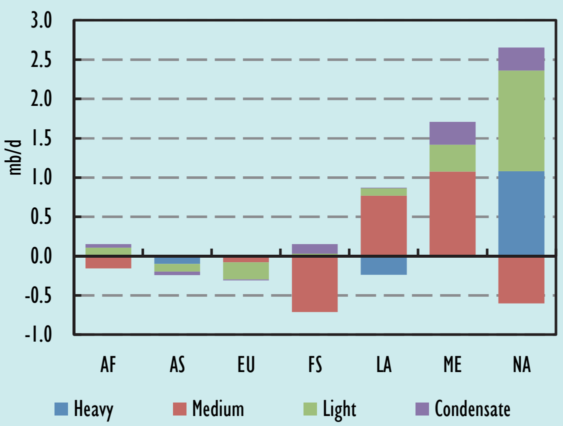
Little changed global averages conceal regional differences, notably in North America, the main driver of global supply growth. The region is forecast to be the main source of additional volumes of both heavy and light crudes, with US LTO and Canadian heavy oil alone growing by over 2 mb/d together over the forecast at the expense of medium conventional grades especially in the Gulf of Mexico. The Middle East will be the main source of medium gravity crude, adding 1 mb/d throughout by 2020, driven by Iraq.

**Figure 4.10** Feedstock actual and projected quality




Note: Bubble area proportional to production size.
Empty bubbles are forecasted values.

**Figure 4.11** Crude supply growth by region and grade




Note: Heavy = <10°; Medium = up to 34°API; Light = up to 45°; Condensate= >45°.

In Latin America, relatively lighter Brazilian supplies will more than compensate declines in Venezuelan extra-heavy crudes, leaving the region 0.65° API lighter and a bit sweeter. North Sea crude quality is getting heavier, with falling production of light grades such as Brent leaving room to heavier and sourer streams, such as Forties and Johan Sverdrup expected to come online later in the decade.

Russian production declines will leave overall Former Soviet Union crude lighter and marginally sweeter as growing Kazakh CPC blend account for a growing share of the region's output. New Australian condensate production is set to move the country's overall API by over 7° to average 43°, causing overall Asian/Pacific supply quality to grow marginally lighter, by 0.2° on average. In Africa, dwindling Algerian condensate volumes will be compensated by medium grades coming online in Angola, leaving the region overall quality little changed at 36.1° API and 0.40% sulphur.

**Box 4.1** Refinery feedstock quality: a light squeeze (continued)

**Travelling light.** Shifts in crude export patterns will compound the effect of production changes to further lighten the quality of traded refinery feedstock as medium and heavy grades will increasingly be refined closer to the wellhead rather than exported. Light crudes and condensate will likely be the only grades whose trading volumes will increase by 2020, albeit marginally. Exports of medium grades are projected to decline by a global 500 kb/d, as refining capacity builds in the producing regions, most notably Africa and Middle East. Saudi export of medium crude will drop by 250 kb/d as new refining projects configured to run domestic sour grades come on line. In Nigeria, a grassroots 500 kb/d refinery and petrochemical project is due to run medium/light West African grades from the international markets at the tail end of the forecast period.

**Figure 4.12** Crude supply growth by grade and region

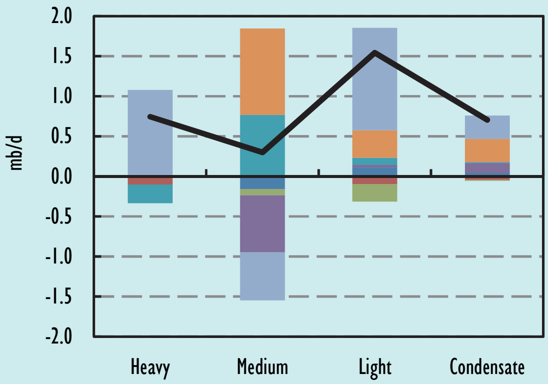
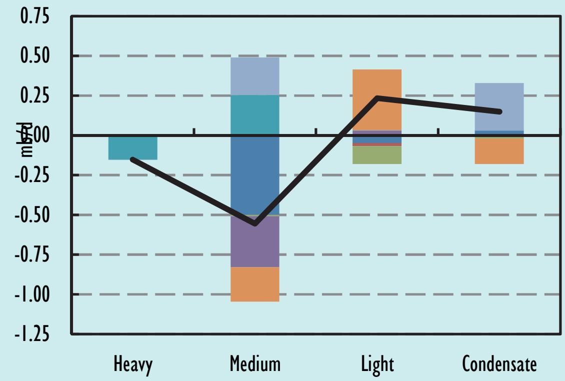



**Figure 4.13** Traded crude growth by grade and region




Africa Asia Europe FSU Latin America Middle East North America World

Note: Heavy = <10°; Medium = up to 34°API; Light = up to 45°; Condensate= >45°.

## Product supply balances

The globalisation of oil product markets continues. Having turned into a net product exporter for the first time in July 2008, the United States has since solidified its position in global oil product trade, with gross exports surging to a record 3.5 mb/d in December 2013. Saudi Arabia is on track to join the club of major oil-product exporters following the completion of two grassroots refineries within the Kingdom and the start of a new product trading company, Saudi Aramco Product Trading Company, in 2012. Whether China joins this club later in the decade, when new projects are completed, or Africa manages to reduce its import dependency by finally getting a refinery project off the drawing board, remains to be seen. Also unclear is how refiners will adapt to the near-disappearance of global fuel oil demand in either 2020 or 2025, as maritime emission regulations are scheduled to come into force (see *Sea changes in bunker fuels*). What is certain is that the refining industry and product trade have embarked on a process of transformation which has yet to run its course.

As refineries become ever more sophisticated, through new builds or upgrading projects, refinery production continues to evolve to meet new demand trends. Over the past decades, fuel oil production has steadily declined as demand for the fuel has shifted to cleaner burning ones. This trend is set to continue in coming years, with fuel oil production on track to fall by more than 1 mb/d through 2020, when output of all other products rise as refinery activity expands. After years of structural declines, fuel oil demand is expected to remain largely unchanged through the end of the forecast, however, with growth in non-OECD economies offsetting further reductions in the OECD. Fuel oil markets are thus set to tighten in coming years, until a global cap on sulphur content of marine fuels is reduced to 0.5% from the 3.5% in 2020, or 2025.

**Box 4.2** Products supply modelling: seeking the pressure points

Our approach to modelling refined product supply is not designed to optimise the global/regional system, but rather to highlight where pressures may emerge within that system in the 2015-20 timeframe. A number of simplifying assumptions underpin the analysis, changes to any one of which generate a significantly different outcome. The aim is to identify any mismatch between existing and planned refining capacity and expected changes in crude feedstock quality and availability given current expectations of product demand growth. In past editions of this *Report*, the IEA model has taken the demand forecast, with global refinery throughput levels feeding off a balance whereby non-OPEC supply is maximised and OPEC acts as swing supplier. As discussed in the *Supply* section, however, the assumption that OPEC members will curb supplies is no longer a given. Rather, OPEC looks set to let inventories build in the near term until a supply response is forthcoming. To reflect this we have set OPEC output at its 30 mb/d target for 2015 and 2016, allowing surplus volumes to be traded and added to inventories, but not refined. Refinery throughputs are still modelled to meet overall demand. The model also assumes that the utilisation of higher-value crude capacity is maximised. Finally, we also assume an operational ‘merit order’, with crude preferentially allocated to demand growth regions and more complex refining capacity. Our approach is non-iterative, when of course, in reality the emergence of imbalances would tend to force changes in operating regime, crude allocation and ultimately capacity and investment levels.

The same legislation will obviously have the opposite effect on middle distillate markets, as a major switch of bunker markets to marine gasoil demand would have profound impact on the refining and shipping industry alike. While current refinery investments are clearly geared towards maximising middle distillate yields, additional volumes are nowhere near adequate to meet such a one-off surge in demand. Already prior to 2020, middle distillates remain the fastest growing markets, despite a recent slowdown in demand growth in China and Other Asia, accounting for 44% of total demand growth through 2019. This represents 2.4 mb/d of additional demand, closely matching additional outputs over this period. For the industry to meet a further 2.6 mb/d gain in 2020, huge investments would have to be undertaken. Upgrading capacity units are very costly, with estimates of new cracking units often surpassing USD 30 000/barrel. Even if companies came through with additional investments, a log-jam in engineering and construction services could be envisaged towards the end of the decade.

Light distillate markets (including naphtha and gasoline), meanwhile, look to remain well supplied in the medium term, as refinery upgrades and increased supplies of light oil, condensates and natural gas liquids lift supplies faster than demand. Around 1.9 mb/d of additional demand for the light fuels is expected through 2020, compared with refinery output increases of nearly 2.5 mb/d. Additional volumes would also come from Natural Gas Liquids (NGLs) fractionation plants and slightly higher ethanol production, causing refiners with excess output to have to compete fiercely for export markets. Further adjustments to the refining system are likely. Indeed, several refiners in the United States has announced decommissioning of gasoline making FCC units, as they prioritise more valuable diesel production.

For **North American** product exports, the past is prelude. The emergence of the United States as a force in product exports had been one of the major market developments of the last few years. Towards 2020, the United States will take OECD Americas product exports to new levels. The region is expected to become a net exporter of light distillates (gasoline and naphtha) possibly as early as 2017, while its middle distillate exports are forecast to hold steady above 1 mb/d until 2020. This spectacular growth largely reflects the continued transformation of the US refining industry and oil product trade in response to ever rising liquids supplies. The United States saw its product exports surge to 3.5 mb/d at the end of 2013, before falling back to an average of 2.8 mb/d in 2014. Net oil product exports averaged around 1.5 mb/d for both 2013 and 2014, making the United States the world's largest oil product exporter and second only to Russia in terms of net exports. Thanks to rising US throughputs, regional net gasoline imports plummeted from more than 1 mb/d as recently as in 2007 to just 0.4 mb/d in 2014, of which the United States only imported a net 150 kb/d.

**Figure 4.14** OECD Americas oil product balances

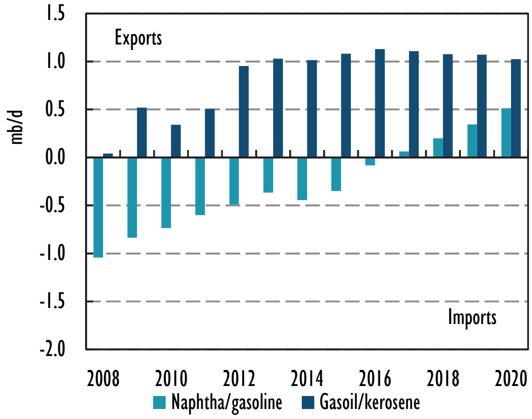
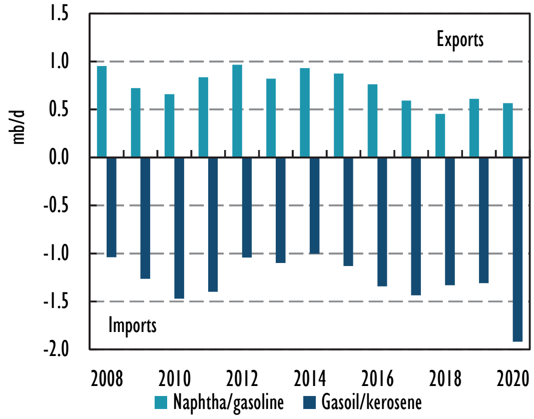



**Figure 4.15** European oil product balances




A large portion of North American middle distillate exports will continue to flow to **Europe**, already the world's largest middle-distillate importing region, whose import dependency is poised to increase further over the forecast period. After a jump in distillate demand in 2015, due to bunker fuel specification changes, both total and middle distillates demand is forecast to ease. Falling demand, combined with increased competition from new, export-oriented capacity in other regions, is expected to cause a reduction in European refinery activity. A switch to low-sulphur bunker fuels from 2020 could see European marine gasoil demand surge, and imports (into both OECD and non-OECD Europe) balloon to more than 1.9 mb/d in 2020, from 1.3 mb/d over the 2014-19 period. As throughput falls, however, so do regional gasoline supplies and surpluses, from 900 kb/d in 2014, to just under 600 kb/d at the end of the decade. With the Americas and the Middle East entering this market, European refiners could struggle to place their surplus barrels.

Rising **Middle East** product exports will have an even greater impact on global oil product markets than the transformation of the US downstream sector in years to come, with outflows coming from three new mega-refineries: Saudi Arabia's 400 kb/d Satorp plant in Jubail on the Persian Gulf, commissioned in 2013, its Yasref facility in Yanbu on the Red Sea, also 400 kb/d, started at the tail-end of 2014 and the UAE's 420 kb/d Ruwais expansion, due to come online in 2015. Saudi product exports got a first boost in December 2013, when the Satorp refinery started exporting products. Net exports surged to an average 370 kb/d in the first 11 months of 2014 from 85 kb/d in the corresponding period a year earlier. Since then, the Yasref plant shipped its first fuel cargoes in January. Once fully operational, it will produce some 260 kb/d of diesel, most of which will be exported. Longer term, Middle Eastern demand growth is set to absorb more of the products at home. Middle Eastern oil product demand is forecast to grow by 1.4 mb/d over the next six years, representing a compound annual growth rate (CAGR) of 2.6%, significantly lower than previously expected.

**Figure 4.16** Middle East oil product balances

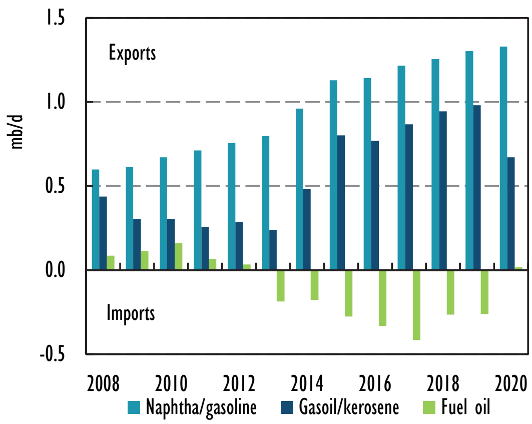
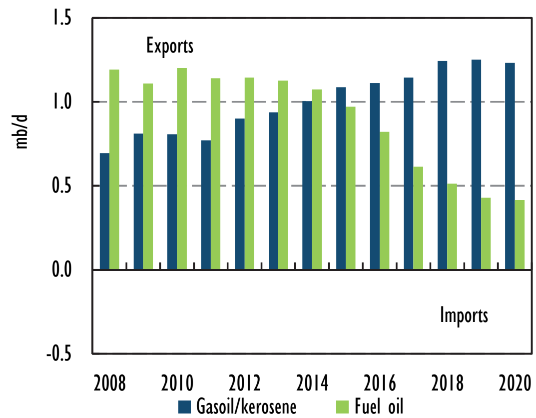


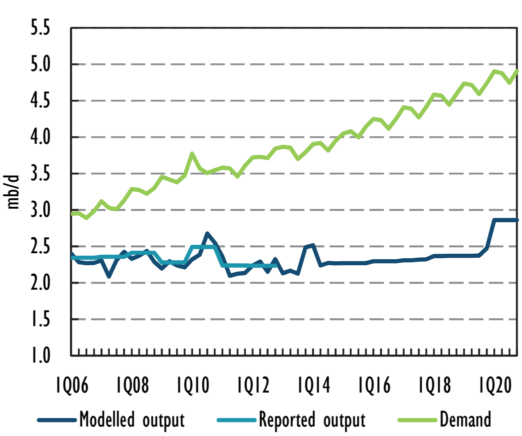

**Figure 4.17** FSU oil product balances




Even as the Americas and the Middle East step up their product exports, the **FSU** will remain the largest product exporter on a net basis. Trade data compiled by Argus Media, based on official customs statistics, pegged total FSU product exports at nearly 3 mb/d in 2013, and slightly higher in 2014. Russian fuel oil shipments (including vacuum gasoil) have so far provided the lion's share of these exports. This will change following the implementation in January 2015 of a new Russian tax regime which will gradually raise fuel oil export duties to the same level as crude oil duties by 2017 (two years behind an earlier deadline). Russian fuel oil exports might continue to flow at high rates for some time, but starting in 2017, oil companies will likely raise crude exports at the expense of fuel oil. Nevertheless, and despite large-scale refinery modernisation plans, the FSU remains a key supplier of fuel oil through the end of the decade. Should the bunker market switch out of residual fuel oil in 2020, this would provide a particular challenge to Russian refiners.

**Africa**, meanwhile, will remain a significant oil product importer for the time frame covered in this *Report*. According to annual statistics compiled in the IEA *Annual Statistics for Non-OECD Countries* (the so-called *Green Book*), the region as a whole imported around 1.7 mb/d of oil products in 2012, partly offset by exports of 700 kb/d, mostly Algerian LPG, naphtha and fuel oil. As African oil demand continues to grow, at a forecast CAGR of 3.3% from 2014 through 2020, so will its import requirements. Total net product imports could rise to more than 2 mb/d before the end of the decade, when new refineries are slated to start up in Uganda, Angola and Nigeria. Irrespective of the ultimate completion date of those projects, Africa is set to remain a significant product importer both in the near and longer term.

**Figure 4.18** African refinery output vs demand



**China** is a wild card for product markets. As its downstream investment plans have been scaled back, so has its oil product export potential. We now expect only 1.5 mb/d of new capacity to come online by 2020, slightly lower than expected demand growth over the same period, though a number of projects could be brought on earlier. Chinese official forecasts call for stronger growth in refining capacity, however. China's top planning body, the National Development and Reform Commission (NDRC), projects capacity growth of as much as 3.4 mb/d of capacity in the 2016-2020 period, and a draft plan for the petroleum and chemical industries released in late 2014 calls for additions of 4.6 mb/d in the decade to 2025. The NDRC argued that lifting investments in the refining industry could mitigate the social impact of the current economic slowdown.

**Figure 4.19** China refinery output vs projected demand

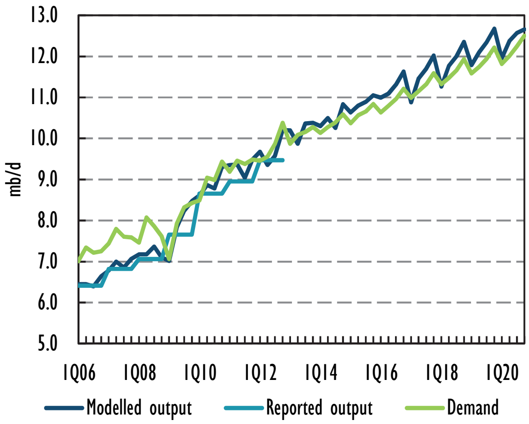
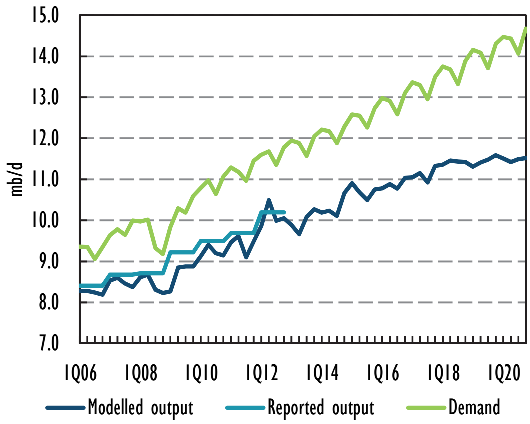



**Figure 4.20** Non OECD Asia refinery output vs projected demand




If such additions were implemented over the coming years, global product markets would evolve very differently than what is outlined here, with China emerging as a significant product exporter. While the implications for both regional and global product markets would be considerable, companies seem unlikely to follow through with these plans. Both PetroChina and Sinopec seem to take a more cautious view of the market and their own investment strategies, and Chinese refinery activity seems more likely to track the country's overall demand growth over the forecast period, as has been the case in recent years. Growing product imbalances are looming, however, given disparities between China's product yield and the changing makeup of its demand barrel. China looks set to become a significant exporter of middle distillates in the medium term, as internal demand growth for the fuel has slowed considerably.

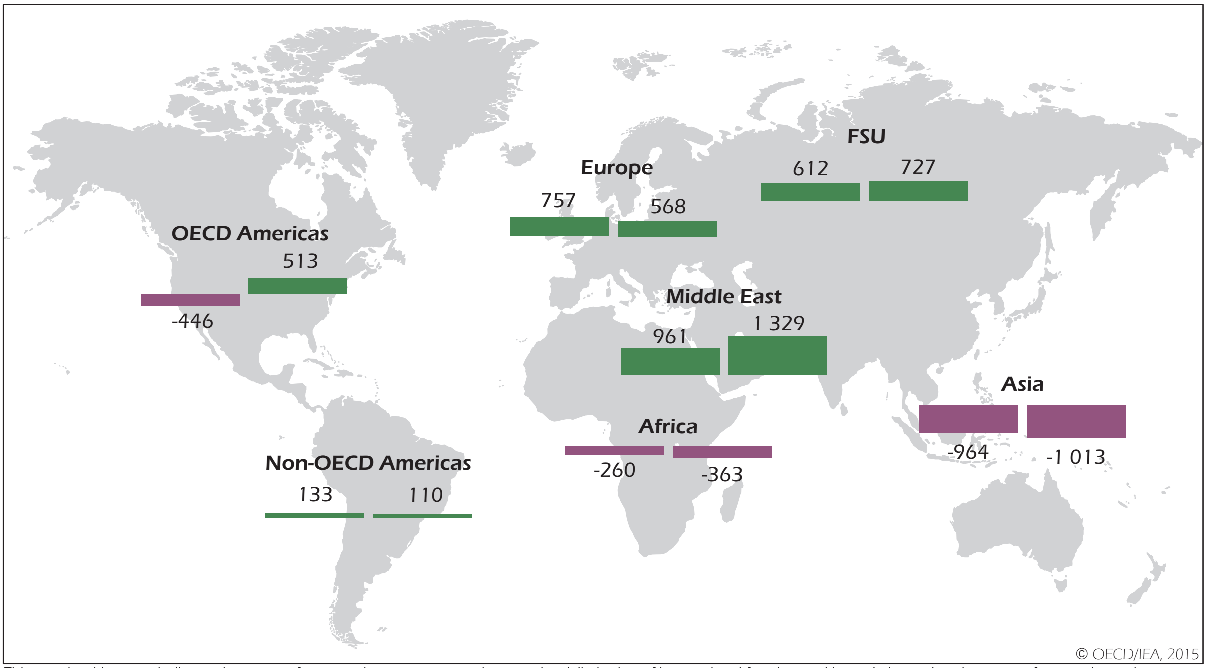
Other Asian exporting countries, such as Korea, Singapore and India, will remain so through the forecast period, with jet kerosene, diesel and other gasoil continuing to supply international markets. The region remains a significant importer of naphtha for its petrochemical use, and of fuel oil for further processing or to supply marine bunker markets. Asia would be one of the most deeply impacted regions by a switch in bunker fuels to lower-sulphur standards considered by the International Maritime Organisation (IMO) if it were to be implemented in 2020 as planned. Refinery closures in OECD Asia Oceania will provide an outlet for other Asian exporters at times, when refinery outputs falls faster than demand.

## *Light distillates markets remain well supplied*

Light distillate markets (including naphtha and gasoline) look to remain well supplied in the medium term. The surge in light crude oil, condensates and natural gas liquids (NGL) production in the United States and the Middle East will not only lead to ballooning ethane and LPG supplies but also to higher refinery output of naphtha and gasoline. Global NGL production is on track to rise by 0.7 mb/d by 2020, while condensate grows by 1.4 mb/d.

**Map 4.1** Product supply balances: gasoline/naphtha

Regional balances in 2014 and 2020 (thousand barrels per day)




This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

On the demand side, both naphtha and gasoline demand continue to grow globally, while maintaining its share of total demand at 33% through the forecast period. Gasoline demand is set to expand by more than 1.5 mb/d by 2020, while naphtha adds 0.4 mb/d, contributing a combined 29% of total net oil demand growth from 2014 to 2020. This headline figure conceals regional contrasts, however. In the OECD, demand for the two fuels is set to contract by a combined 0.6 mb/d. Even in the United States, where lower gasoline prices support an increase in miles driven and a resurgence in SUV sales, efficiency gains in the vehicle fleet are expected to result in a demand contraction of some 0.2 mb/d over the forecast period, a much smaller decline than foreseen in last year's *Report*. That sets North America on track to become a significant exporter of light distillates, with net outflows projected at 0.5 mb/d by 2020, compared with net imports of nearly 500 kb/d in 2014.

Europe is expected to remain a net gasoline exporter as lower regional refinery runs offset structurally contracting demand, but surpluses are projected to ease slightly towards 2020. With the United States becoming increasingly long gasoline and the US export market quickly eroding, gasoline cracks will remain under pressure as European refiners face tougher competition for export outlets.

Increased NGL production and refinery activity underpin higher naphtha and gasoline volumes also in the Middle East. Regional demand for motor fuel is growing at a rapid clip, however, as is petrochemical demand for LPG and naphtha. The region is nevertheless expected to retain its massive naphtha overhang, which to a large extent feeds Asia's growing petrochemical needs. The region is projected to export just around 1.4 mb/d of naphtha in 2020. Africa's light distillate import requirements rise to some 0.4 mb/d in 2020, from just under 0.3 mb/d estimated in 2014, assuming new projects come on line. Should these yet again be deferred or cancelled, however, imports would have to rise further to meet some 270 kb/d of demand growth projected. Africa imported just over 400 kb/d of gasoline net in 2012, while exporting some 200 kb/d of Algerian naphtha.

**Figure 4.21** Atlantic basin gasoline balances

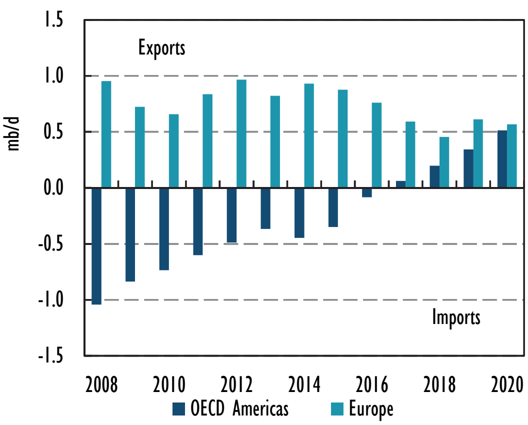
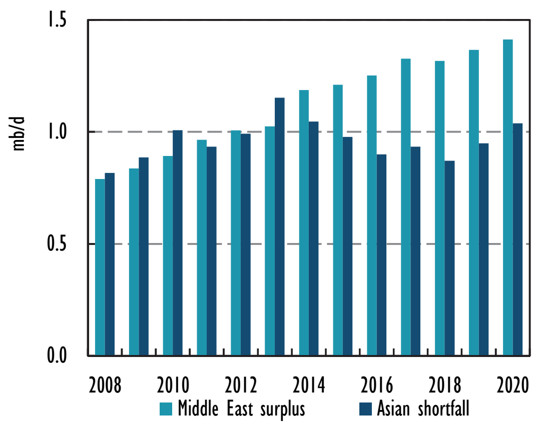



**Figure 4.22** Key regional naphtha balances




## *Middle distillates to remain refinery mainstay through 2020*

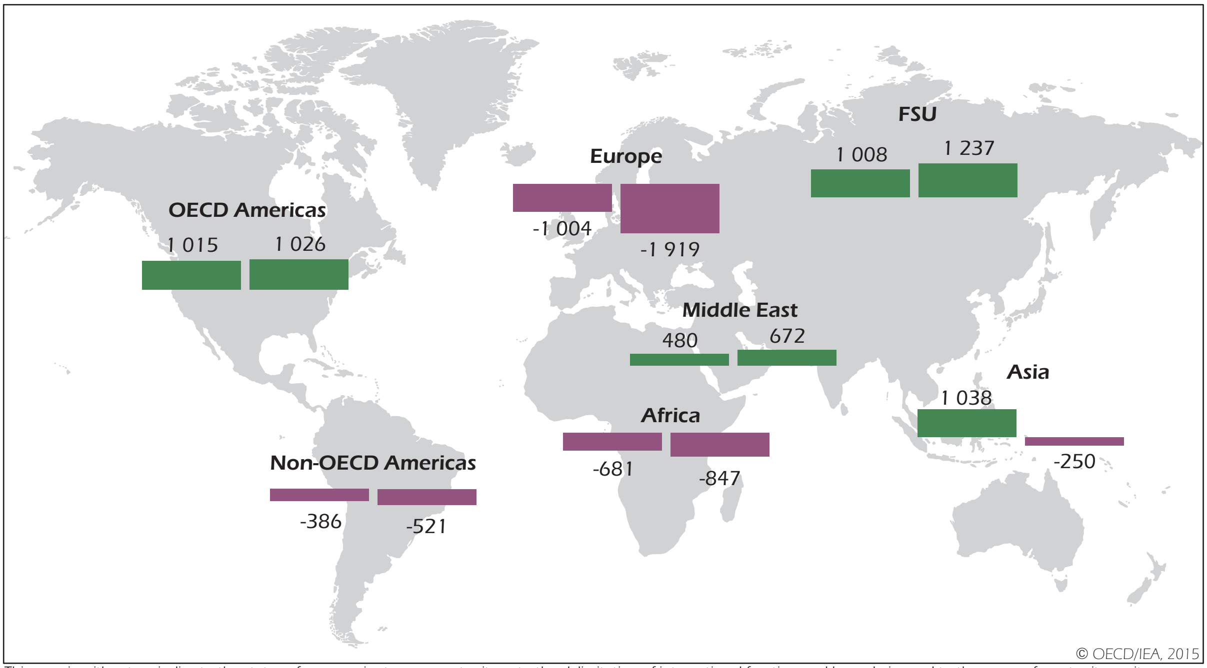
Despite a recent slowdown in growth, middle distillates continue to provide the bulk of projected demand growth, accounting for 44% through 2019, before a potential switch in bunker fuels to marine gasoil in 2020 completely throws off the balance by adding another 2.6 mb/d of demand in just one year. Taking 2020 into consideration, middle distillates account for 76% of net global demand growth, or more than 5 mb/d. Current refinery expansion plans and upgrading projects have the potential to lift global diesel, gasoil and kerosene output by 2.8 mb/d in total, leaving a large shortfall in global supplies at the end of the decade. As such, the middle of the barrel will provide both enormous challenges and opportunities for refiners.

Barring a delay to the proposed bunker specifications to 2020, or a larger uptake of scrubbing technology or LNG fuelled vessels, huge investments needs to be undertaken in the refining industry to meet the additional gasoil demand. To upgrade some 2 mb/d of fuel oil to gasoil material, through hydrocracking or coking capacity, extensive additional investments would be needed. In addition to the huge investment requirements, these large complex upgrading projects have long leadtimes from conception to completion. A potential engineering and construction log-jam would create a further hurdle that would have to be overcome.

According to the latest available annual oil statistics jet kerosene, diesel and other gasoil accounted for 40.4% of total refinery output in 2012, up from 37% a decade earlier. While refinery upgrading investments are clearly geared towards raising distillate yields further towards the end of the decade, total middle distillate yields remain remarkably stable, increasing just to 41.3% by 2020. The FSU could raise middle distillate yields by 5% from 2014 to 2020, as fuel oil's share plunge by 10.2%. Output of naphtha, gasoline and other products also rise sharply as refinery upgrades are completed.

**Map 4.2 Product supply balances: gasoil/kerosene**

Regional balances in 2014 and 2020 (thousand barrels per day)




This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Middle distillate yields in the Middle East are equally on track to rise, as new refineries start up. Indeed, the region already lifted middle distillate output significantly over 2013 and 2014, in large part due to the completion and ramping up of Saudi Arabia's Jubail and Yanbu refineries. Indeed, both projects have impressive distillate yields, with the Yanbu refinery scheduled to produce 262 kb/d of diesel out of 400 kb/d of crude processed, representing nearly 66%. Regional demand growth for jet and diesel over the period, of almost 800 kb/d will absorb most of the added output however, resulting in only 200 kb/d of additional exports in 2020, though sharply higher exports are expected in the near term. Petrobras' new Abreu e Lima refinery in Brazil will have a ULSD yield of 70% once fully operational. But this has come at a cost. The plant, which shipped its first product cargo in January of this year, is estimated to have cost nearly USD 20 billion. Latin American middle distillate import requirements nevertheless rise to 0.5 kb/d in 2020, from 0.4 mb/d in 2014.

Europe remains the largest regional importer of middle distillates through 2020. A combination of lower refinery activity, while middle distillates demand still sees growth, could see regional import requirements balloon to 1.9 mb/d at the end of the decade, when also bunker fuels switch from fuel oil to distillates. Middle distillate's share of total European oil demand is set to grow to 55% in 2019, and 58% in 2020, from 53% in 2014, while overall demand falls by 0.5 mb/d.

The largest overall changes in middle distillates markets are expected to come from Asia. As a whole, regional (including OECD and non-OECD Asia and China) middle distillate surpluses hover around the 1 mb/d mark through 2019, but with diverging patterns across sub-regions. Within Asia, China, due to its slowing middle distillate demand, could see exports rise from around 70 kb/d in 2012 and around 200 kb/d in 2014, to as much as 900 kb/d in 2020. OECD Asia Oceanian countries meanwhile see exports falling from roughly 0.5 mb/ d in 2013 to 0.3 mb/d in 2019, while non-OECD Asia flips into a net importer over the same period. Due to its very high bunker demand for fuel oil, especially in Singapore, the world's largest bunker port by volume, the switch to lower sulphur fuels will have particularly stark implications for this region. Singapore alone is estimated to consume nearly 0.8 mb/d of bunker fuels in 2020, of total Asian bunker demand of 1.6 mb/d. If this switches to marine gasoil as outlined in *Sea change in bunker fuels,* Asia could flip from a 1 mb/d surplus of middle distillates in 2014 to a deficit of 0.3 mb/d in 2020.

**Figure 4.23** China refinery gasoil/kerosene output vs forecast demand

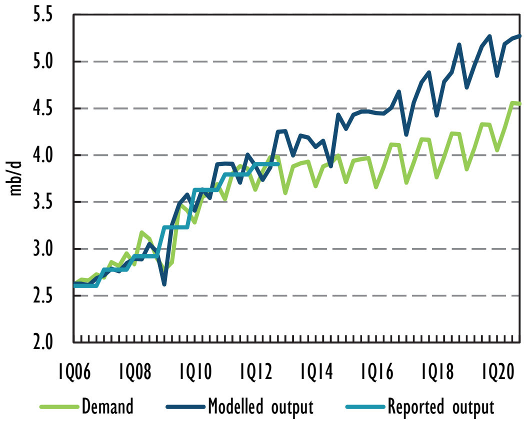
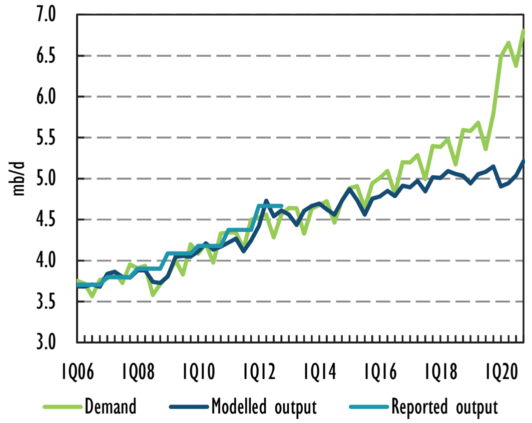


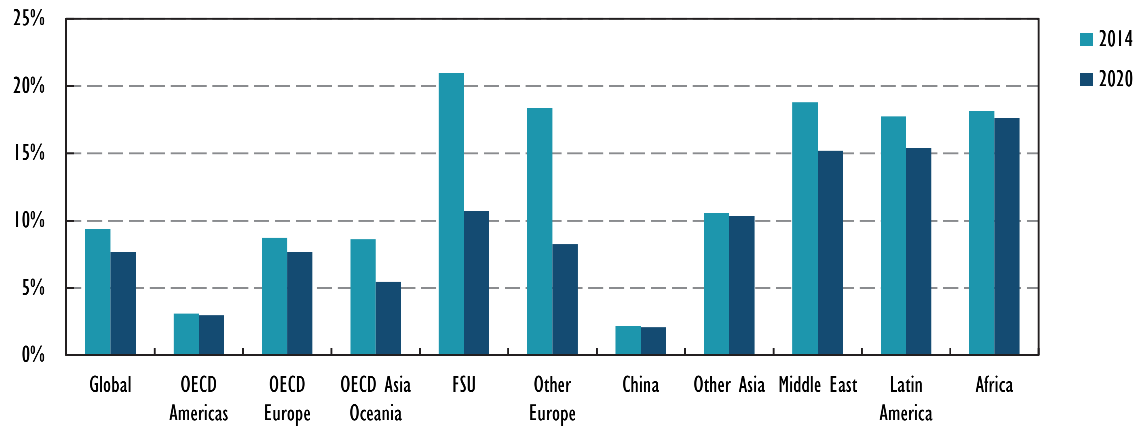

**Figure 4.24** Non-OECD Asia refinery gasoil/kerosene output vs forecast demand




### *Fuel oil collapse as bunkers switch to lower sulphur fuels*

On the flip side, a major switch of bunker fuels to marine diesel in 2020, would have as major an impact on global fuel oil markets. Fuel oil surpluses were already looming, as demand increasingly switches to lower sulphur alternatives, for all uses. With fuel oil used as a bunker fuel in international shipping set to fall to only 1 mb/d in 2020, from around 3.2 mb/d in 2014, enormous challenges emerge for the refining industry and consumers alike.

**Figure 4.25** Regional refinery fuel oil yields

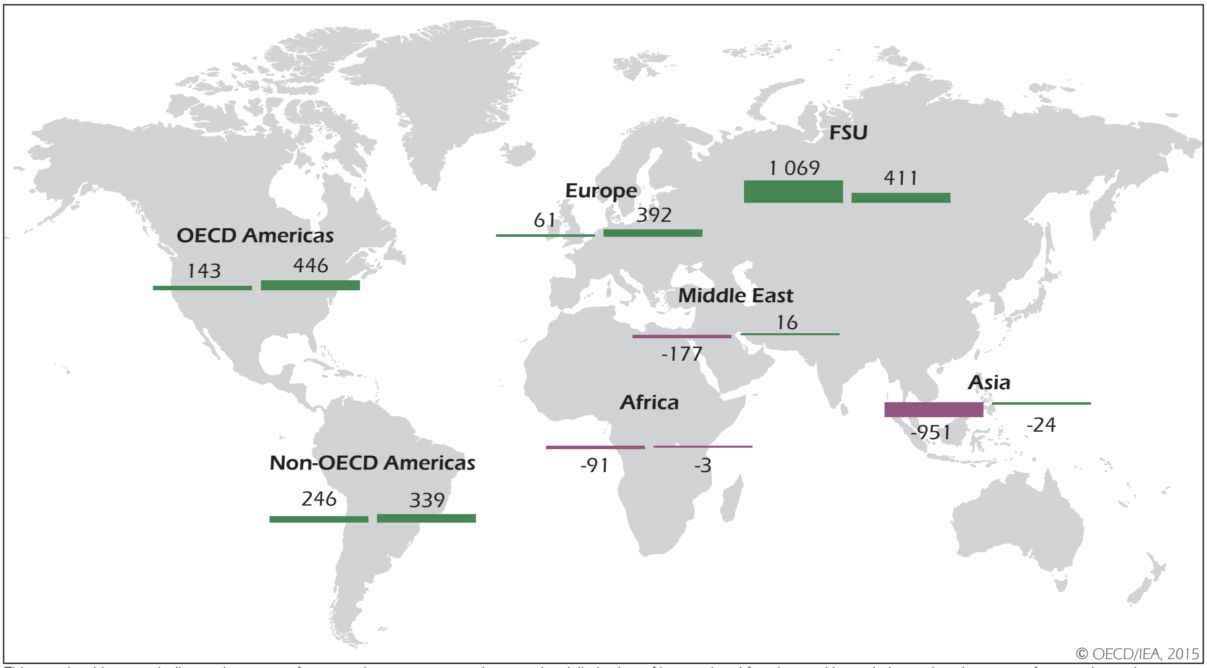


Current refinery upgrading investments are set to reduce global fuel oil output further. Already in 2014 we estimate global fuel oil yields to have fallen to 9.1% and further reductions are due in coming years as new upgrading units come on line. Given announced investment plans, fuel oil production could fall to less than 8% of output in 2020. The biggest changes are naturally coming from regions with the highest fuel oil production currently. The FSU sees its fuel oil output drop from 21% in 2014 to 11% in 2020. The massive investments and improvements nevertheless leave the region with nearly 0.8 mb/d of output, for which it will struggle to find markets should bunker demand fall away. One option is that Europe and Asia continue to import the heavy fuel for further processing. In 2014, OECD Europe imported some 400 kb/d of refinery feedstocks from the FSU, primarily fuel oil grade material. Asian fuel oil yields are also on track to shrink. In OECD Asia Oceania, refinery restructuring and consolidation could see the yield fall to only 6% at the end of the decade, from 9% currently. Middle Eastern rates fall 3.6 percentage points to 15% in 2020.

As a result, the current fuel oil sink in Asia will all but disappear. In 2012, Asian fuel oil imports were 2.3 mb/d, while exports stood at 1.1 mb/d. With bunker demand switching to lower sulphur alternatives, the region could be nearly self-sufficient in fuel oil in 2020. This would create a massive headache for regions such as the FSU, Europe and the Americas, which all become increasingly long on the heavy fuel.

**Map 4.3** Product supply balances: fuel oil

Regional balances in 2014 and 2020 (thousand barrels per day)




This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

# 5. SEA CHANGE IN BUNKER FUELS

## Summary


- **By the end of the decade, a broad tightening of international standards for marine bunkers has the potential to significantly lighten the demand barrel, as it would require up to 2.2 mb/d of residual fuel oil demand to switch to lower-sulphur marine gasoil.**

- **Environmental legislation is catching up with the shipping industry, one of the last major strongholds of high-sulphur residual fuel oil demand. The International Maritime Organisation (IMO) plans to introduce a global 0.5% sulphur cap on marine bunkers by 1 January 2020.** Although implementation could be postponed to 2025, this *Report* follows current policy and assumes that the earlier target date will be maintained.

- **Of the three options available to shippers to comply with the new standards, modest investments by the shipping industry in abatement technologies (scrubbers) and LNG fuelled vessels would entail a large-scale switching to marine gasoil.** To meet this additional middle distillates demand, extensive investments would be required by the refining industry.

- **New shipping standards will contribute to lift global gasoil demand to an estimated 31.5 mb/d in 2020, up by 2.4 mb/d from 2019 and up by 4.5 mb/d from 2014.** Marine demand will account for 10% of total gasoil demand by 2020.

- **Broad changes in product quality will require a wholesale shift in refinery yields and product output.** Higher marine demand for middle distillates will significantly increase distillate cracks and shipping costs.

- **Changes in the global fuel mix in 2020 will also necessitate adjustments in midstream infrastructure, including import terminals and storage capacity**, to deliver the lighter marine gasoil.

- **Overall marine fuel demand is set to increase only marginally, by an estimated 0.2 mb/d**, reaching 4.1 mb/d by 2020, as efficiency gains partly offset the impact of economic growth and rising inter-continental trade.

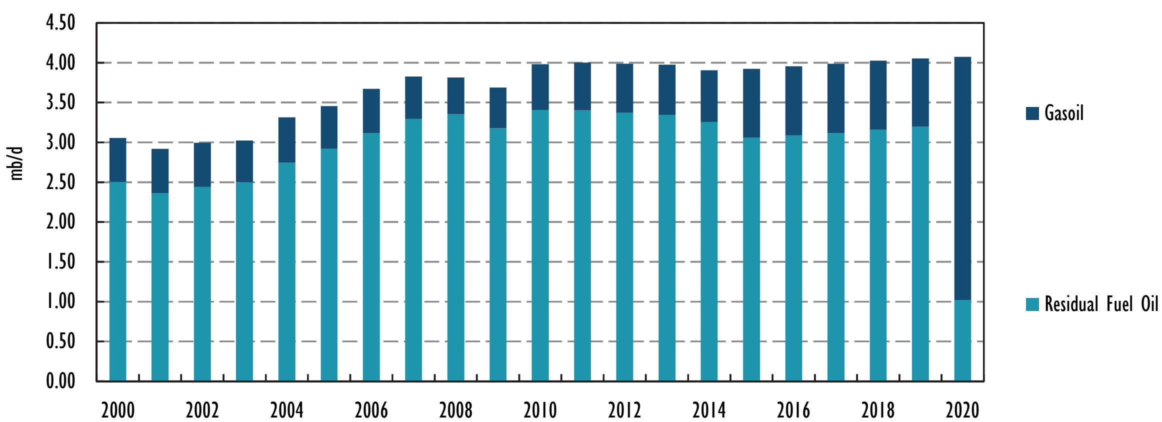

## Overview

The global shipping market is set to undergo a sea change at the end of the decade due to significant tightening of the regulatory framework concerning vessel emissions. The imposition of more stringent environmental standards for vehicle fuel emissions had long spared the shipping industry, but concerns are mounting over the damage done to the marine, terrestrial and atmospheric environment from the combustion of liquid fuels by vessels' engines. Much of the new legislation will concern emissions of sulphur oxides ($SO_x$). As of 1 January 2015, a cap of 0.1% on the sulphur content of vessel emissions has already been introduced in so-called Emission Control Areas (ECAs), which include a growing set of coastal areas in Europe and the Americas. The end of the medium-term horizon coincides with incoming International Maritime Organisation (IMO) legislation to reduce the maximum permissible sulphur content of marine fuels to 0.5% from the 3.5% currently allowed. Presently planned to be introduced as of 1 January 2020, this global cap could be deferred to 2025 depending on the outcome of a fuel-availability study to be conducted by 2018 at the latest, on behalf of the IMO. Since the 2020 introduction of the legislation is considered current policy, the projections contained in this chapter are based on its introduction then.

International shipping consumes two main types of oil-based fuels, high-sulphur residual fuel oil (HFO, also known as Bunker C) and a type of lower-sulphur distillate product known more or less interchangeably as marine gasoil oil (MGO) or marine diesel oil (MDO). In this *Report*, the term MGO will henceforth be used generically to refer to all types of middle-distillate bunker fuels, despite slightly different specifications. As environmental legislation is tightened, vessel owners face a set of three options to comply with the new standards: they can burn Bunker C in tandem with on-board abatement technology to 'scrub' emissions to a permissible standard, switch to a compliant MGO, or adopt liquefied natural gas (LNG) as bunker fuel. While each option has its own costs and benefits and all three will likely be required, the vast majority of vessel owners are expected to choose to switch to MGO. With the introduction of the 0.1% sulphur cap in ECAs in 2015, approximately 0.2 mb/d of marine demand is forecast to switch from residual fuel oil to gasoil. Marine demand will be little changed henceforth to 2019, but by 2020 a new step in fuel switching is projected as, despite modest investments by the shipping industry in abatement technologies and LNG fuelled vessels, a large-scale switching to marine gasoil is projected. Accordingly, up to 2.2 mb/d of fuel oil demand from shipping is forecast to switch to gasoil. To meet this additional middle distillates demand, extensive investments would be required by the refining industry.

Aggregate growth in total marine fuel demand is projected to remain modest, however. All told, the bunker fuel market is set to increase by 170 kb/d to 4.1 mb/d in 2020 as efficiency gains partly offset the impact of economic growth.

**Figure 5.1** Oil-based marine fuel consumption in international navigation




As gasoil becomes shipping's fuel of choice, total global gasoil demand will undergo a step change, rising to 31.5 mb/d by 2020, up 2.4 mb/d from 2019 and 4.5 mb/d above 2014 levels. Moreover, absolute growth over 2019-20 is only slightly lower than growth posted over the previous six-year period to 2019. The proportion of total gasoil demand accounted for by marine bunkers is seen to rise to nearly 10% by 2020, up 6.6 percentage points on 2019. At the same time, as fuel oil bunker demand decreases by 2.2 mb/d, total fuel oil demand will plunge to 5.3 mb/d in 2020. By the end of the forecast, the shipping industry's share of total residual fuel oil demand is projected to drop to 19%, from 43% in 2019.

The switch will require large-scale adjustments in refinery yields and product output. Large-scale complex refineries in the Middle East and non-OECD Asia, including new builds due to come on stream during the forecast will be at the forefront of supplying MGO to international markets. China also has the potential to export extra volumes of gasoil, but planned refinery expansions there have been scaled back as policy has so far prioritised meeting domestic demand, rather than targeting export markets. Russia, currently a leading supplier of high-sulphur residual fuel oil to the shipping industry, is in the midst of a broad upgrade of its refining industry to maximise lighter-product yields, and may emerge as a major supplier of marine gasoil, to Europe and further afield.

**Figure 5.2** Total gasoil demand

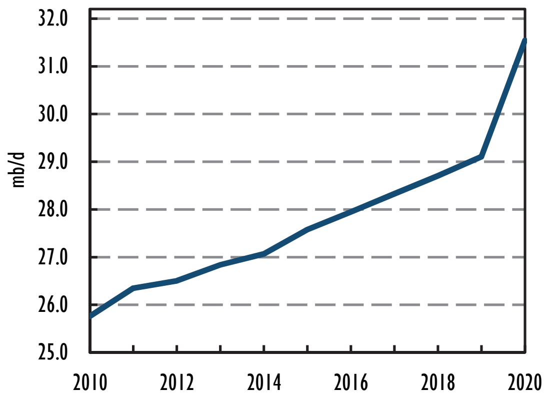
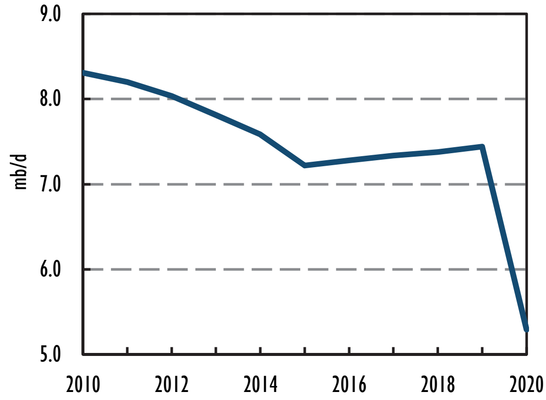



**Figure 5.3** Total residual fuel oil demand




Adjustments will also be required in midstream infrastructure to meet the new bunker fuel mix, including terminal infrastructure such as pipelines, storage tanks, berths and bunker barges. This will especially be the case in mature markets where the required volumes of gasoil will be imported rather than locally produced, and where the import infrastructure will need to be partly reconfigured to permit the import of large volumes of gasoil. Such developments may cause some shift in the location of bunker terminals, with new refining hubs in non-OECD economies growing in importance also as bunker hubs, taking market share away from established terminals in importing regions.

Given the large scale of the expected switch, the marine fuel market will experience some pricing volatility as the industry rebalances. As refiners upgrade plants to reduce fuel oil output ahead to the 2020 legislative switch, tanker owners are expected to continue to burn the heavy fuel as long as possible. In 2020 however, the large scale increase in gasoil demand will likely boost gasoil prices sharply. Higher marine demand for middle distillates will also significantly increase distillate cracks and shipping costs.

## *Bunker demand today and tomorrow*

Bunker demand is, by its international nature, poorly measured and imperfectly captured in statistics, with commonly quoted estimates ranging between 3.5 mb/d and 6.5 mb/d for 2012. Such an exceptionally wide range reflects the fact that international marine bunkers are often reported as exports but never as imports, as they are burned at sea. Bunkers can also be misreported as domestic demand. In this *Report*, global bunker demand is estimated at 4 mb/d in 2014. This marks an upward adjustment from estimates in the IEA's *World Energy Statistics and Energy Balances* 2014, intended to correct for under-reporting in the Former Soviet Union (FSU) and non-OECD Asia, where marine bunkers in many cases are misreported as fuel oil for inland consumption. In addition to bunker volumes used in international shipping, an additional 1 mb/d was used globally in 2014 for domestic navigation and included – appropriately, in this case – under domestic consumption. For the purpose of this *Report*, only international marine bunkers are considered.

Global demand for international marine bunkers is projected to modestly expand by 0.2 mb/d to 4.1 mb/d in 2020. This equates to compound annual growth of 0.7%, considerably less than global GDP growth and well below the growth experienced over the past 20 years which was much more in line with global GDP and driven by increased exports from the non-OECD to OECD. It also adjusts for the slow encroachment of LNG into bunkering over the forecast when it is expected to account for approximately 0.2 mb/d of bunkering demand in 2020.

Increases in efficiency will come in part from the introduction of larger vessels which take advantage of economies of scale. For example, Maersk received delivery of the first of its Tripple-E class vessels in 2014. These vessels are capable of carrying 18 000 twenty-foot containers (TEU), compared to the previous biggest vessels which could transport 15 500 TEU, and were specifically built to transport goods between Asia and Europe where ports are capable of receiving such enormous vessels. Maersk has ordered 20 of these ships, due for delivery by mid-2015.

A further dampener on bunker demand is also set to come from the continued prevalence of so-called "slow steaming", a practice reducing the vessels' speed to cut their fuel use. Despite falling bunker prices, this practice, widely adopted by the shipping industry during recent periods of high oil prices, looks set to continue as many vessel markets tackle oversupply issues (see Box 3.3 *Trends in the tanker industry*).

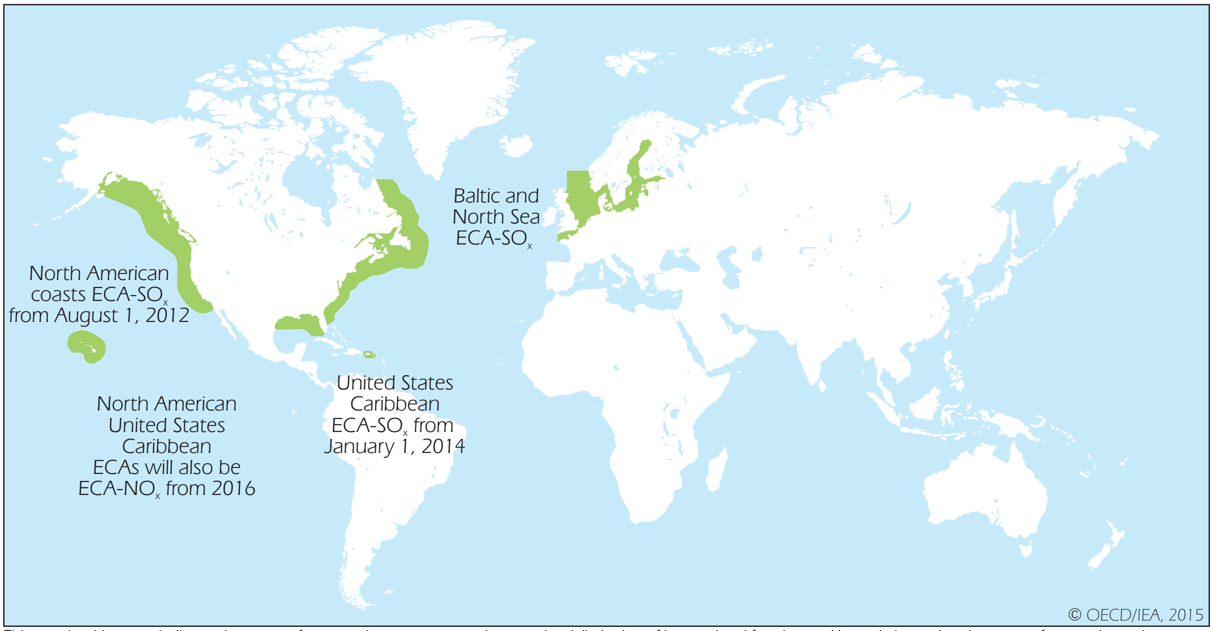
### *Bridging the gap in vessel emission rules*

The IMO has been the driving force behind vessel emissions since the 1970's with specific protocols concerning environmental pollution included under the International Convention for the Prevention of Pollution from Ships (MARPOL). MARPOL Annex VI concerns air pollution and initially set a global fuel sulphur limit of 4.5% with the aim of gradually reducing this over time in line with technology and efficiency improvements. From 1 January 2012, the global cap was tightened further to 3.5% which still permitted vessel owners to use residual fuel oil. It also set out the creation of Emission Control Areas (ECAs), special zones where tighter restrictions on the sulphur content of marine fuels could be put in place. From 2010 the sulphur limit in these zones was 1.0% and this was further tightened to 0.1% beginning 1 January 2015.

The IMO is currently planning to implement a further amendment to Annex VI which sets out a global sulphur cap for marine fuels of 0.5% beginning 1 January 2020, subject to the results of a fuel availability study to be delivered by 2018. This global cap will effectively prohibit the use of residual fuel oil in ships unless on-board abatement technology is installed to cut the sulphur content of emissions to 0.5%.

The European Union also plans to cap the sulphur content of fuels used within its exclusive economic zone (EEZ), which extends to 200 nautical miles off the EU coastline, to 0.5% from 1 January 2020, irrespective of the final timing of IMO regulations.

**Map 5.1** Emission control areas as of 1 January 2015




This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

## *Options for meeting new emission standards*

Since most residual fuel oil has a sulphur content above 1%, it will essentially be prohibited in ECAs from 2015 onwards and globally from 2020 without on-board abatement technology. The other two options available to ship owners to comply with the new emission standards are running an alternative fuel with a sulphur content equal to or below the sulphur emission level required, and switch to LNG.

## *On-board abatement technology*

On-board abatement technology – otherwise known as scrubbers – is unlikely to become the favoured option as ship owners attempt to comply with new emission standards due to their high costs, mostly the high upfront purchase price of the equipment, the opportunity costs of taking the vessel out of service for time-consuming retrofitting work, and the loss of on-deck cargo space to make room for the scrubber.

Not all scrubbers use the same technology but they all work on the same principle of cleaning a vessel's emissions after the combustion process before they are discharged into the air or water. They therefore permit the use of residual fuel oil.

Scrubbers can be included in new builds and can also be retro-fitted to existing vessels. In order for a vessel to be retro-fitted with a scrubber it must spend time in dry-dock, followed by more work which can be carried out at sea. In most vessels, retro-fitting can be carried out with minimal reconfiguring of the engine since no extra fuel tanks are required while the scrubber system itself is relatively small.

Scrubber economics depend on two main variables: the age and expected remaining lifespan of the vessel and the spread between HFO and MGO prices. The discount of HFO to MGO must be wide enough that the savings realised from burning the higher-sulphur fuel fully offset the scrubber's upfront installation costs, estimated at USD 3 million to USD 5 million. The ship's remaining lifespan must be long enough to afford a payback on the initial capital investment. Finally, until 2020, the vessel must spend enough of its time in emission-control areas to make the installation worthwhile. Accordingly, BIMCO, the world's largest international shipping association, estimated that, assuming a spread of USD 258/mt between HFO and MGO, a vessel with ten years commercial life left would have to spend 33% of its time in an ECA over a ten-year period for a scrubber to break-even. Implementation of a global cap in 2020 would effectively increase the amount of time a vessel spends in emission-control zones to 100%, thus raising the financial incentives of installing a scrubber.

A final important point concerning scrubbers has to do with the possibility of a further tightening of marine sulphur regulations. Considering that the sulphur limit in the Northern European ECA is 0.1% but 0.001% for road diesel in Europe, there is scope for stricter controls on marine fuels. Industry participants have raised doubts that present scrubber technology can meet sulphur standards of less than 0.1%. Further tightening of emission standards could thus render scrubbers obsolete, whether they are retro-fitted on existing ships or installed on new builds.

Scrubber uptake so far seems to have remained small (400 vessels globally) and limited to vessels which are likely to spend all of their time voyaging in ECAs. Notable orders have been received from the passenger and "roll on roll off" (RORO) ferry sectors.

### *Marine gasoil*

As per IMO safety regulations, all liquid fuels used in vessel engines must have a minimum flash point of 60°C. This rules out the use on vessels of on-road motor fuels such as road diesel and motor gasoline, both of which have flash points well below MGO's 60°C flashpoint. The conversion of a vessel to be able to run on MGO is not overly expensive and consists of the cleaning of bunker tanks to contain MGO rather than HFO (most vessels have a number of segregated bunker tanks) while vessels are generally as efficient running MGO as HFO. Nonetheless, issues concerning the suitability of alternative low-sulphur distillate fuels bear consideration. A number of marine-engine suppliers have raised the possibility of below-par engine performance due to the differences between residual fuel oil and distillate fuels, notably in terms of flashpoint and viscosity. Safety issues have also been raised by engine manufactures and vessel owners, who run dual fuel engines. The main safety concern is the threat of thermal shock to the engine when switching at sea from viscous HFO which needs to be heated, to unheated MGO, when entering into an ECA. In a worst-case scenario, the 'shock' can disable propulsion systems leaving vessels drifting out of control.

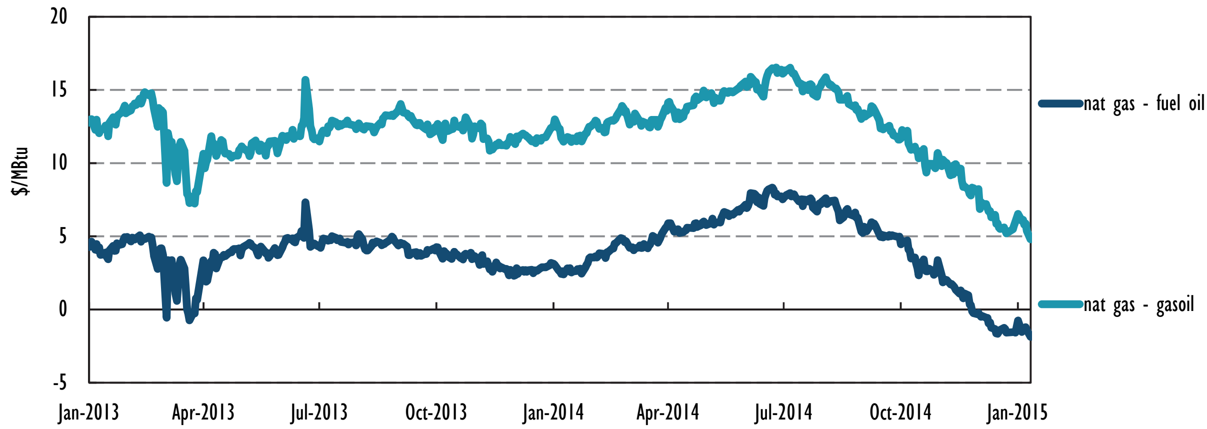
This has prompted a number of refiners and suppliers, including ExxonMobil, Lukoil, CEPSA, Neste Oil, Total Marine Fuels Germany and Atlantic Gulf Bunkering (US), to produce distillate fuels that share some properties with residual fuel oil, for example the Premium Heavy Distillate Marine ECA 50 (HDME 50) produced by ExxonMobil at its Antwerp refinery. This fuel is aimed at vessels running residual fuel oil on the high seas but switching to 0.1% sulphur fuel when in ECA's. Since both the HFO and HDME have to be heated, the risk of thermal shock to engines during fuel switchover is minimised.

### *LNG*

LNGs use as a bunker fuel has, until recently, been limited to the natural gas carriers where the natural boil-off (vapours created from ambient heat input) of a vessel's cargo was used as a propellant. However, vessel owners outside of this sector are now exploring the possibilities of LNG as a bunker fuel. LNG is significantly 'cleaner' then oil products and as such exceeds all current and future IMO environmental requirements. According to the American Clean Skies Foundation, the burning of LNG emits 85% less Nitrous oxide ($NO_x$) and $SO_x$ than HFO.

LNG's confinement to the LNG transportation sector essentially comes from the specific conditions and safety considerations required to store and use LNG on board ships. Firstly, in order for natural gas to remain in liquid form, it must be cooled to minus 162°C. This requires heavily insulated storage tanks that take up more space on ship than a conventional liquid fuel tank. Det Norske Veritas (DNV), an organisation active in the LNG transportation market, estimates that an LNG tank requires 1.8 times more volume than a MGO tank on an equal energy content basis. This makes retrofitting vessels with LNG-powered propulsion systems expensive, while even for new builds, the extra space taken up by tanks takes place away from cargo volume, reducing a vessel's profitability.

**Figure 5.4** Differential between natural gas delivered at UK National Balancing Point and fuel oil and Rotterdam barge prices for gasoil and fuel oil




Despite the large initial capital cost of equipping a vessel to run on LNG (LNG-fuelled vessels are 20% to 40% more expensive to build than an equivalent vessel running on oil), the variable costs (i.e. bunker fuel price) could be significantly cheaper than fuel oil. However, this depends on differentials between refined product prices and natural gas. Although natural gas and refined product prices vary significantly by region, in Europe, as fuel oil and gasoil prices have plummeted over recent months, their premium to natural gas, on an energy content basis, has diminished. On this basis, by early-January 2015, fuel oil was trading at a discount to natural gas. If low refined product prices were to persist, this would reduce the economic incentive to bunker with LNG.

An additional challenge will come from economies of scale. In Europe, the price of gas delivered to a major UK port such as Southampton reflects not only the price for dry natural gas at the UK National Balancing Point (delivery point of the ICE contract), but also the cost of delivery to the port. Economies of scale also play into this; the greater volumes of LNG bunkered in a port, the greater the need for infrastructure to facilitate the efficient bunkering operations which, in theory, would lead to a relative decrease in prices versus less developed ports with small LNG bunkering activity.

The infrastructure for LNG bunkering is at a nascent stage. The distribution network needs to be built out to facilitate large flows between major LNG hubs and smaller bunkering stations. In-port infrastructure also needs to be constructed, including storage tanks (either floating or land-based) and LNG barges or berths for delivering the fuel to vessels.

Lastly, there is currently no clear set of international regulations governing how the bunker fuel is handled both in-port and on ships. To a certain extent, the interest in LNG as a bunker fuel for merchant vessels has taken the industry by surprise. Presently, a number of organisations including engine manufacturers, governments and safety solutions companies are formulating 'best practice' procedures. The importance of internationally-recognised legislation has been demonstrated by a number of vessel operators making public statements that although they see LNG as the bunker fuel of the future, no investments will be made until clear guidelines are introduced.

### Enforcement issues

This study assumes that the stricter legislation in ECAs will be adhered to by vessel owners. Nonetheless, there are several outstanding questions concerning the enforcement of the legislation, especially in the Northern European ECA.

In the United States, the regulations have been incorporated within Federal law 40 CFR § 1043. Penalties for violation will be strict, issued publicly and swift. The US Environmental Protection Agency (EPA) is responsible for the legislation's enforcement and together with the US Coast Guard, it has already boarded vessels to take fuel samples and verify compliance with pre-2015 legislation. The EPA has also explored the idea of conducting vessel flyovers to assess vessel smokestack emissions (HFO emissions are darker than those of MGO) while it has the authority to review vessel documents, notably bunker delivery receipts. If a vessel is found to be in breach of legislation, its owners can be prosecuted under the Act to Prevent Pollution from Ships (APPS) with the US Customs and Boarder Protection given authority to detain vessels if a violation is suspected. Individuals potentially face a fine up to USD 250 000 and a maximum ten year prison term for each violation.

In Europe the picture is more opaque. The Northern European ECA borders 12 countries; Belgium, Denmark, Estonia, Finland, Germany, Latvia, Lithuania, the Netherlands, Norway, Russia, Sweden and the United Kingdom, which presents logistical difficulties in coordinating the coastguards of these states. Nonetheless, a number of countries have expressed their commitment to enforcing the tighter legislation. Notably, Denmark recently stated that it will install monitoring sensors on Danish bridges and also utilise air surveillance and monitoring. The Danish administration also stated that it will 'respond firmly to any violations of the new regulations'.

### Industry response

Initial indications are that the vast majority of vessels spending at least a portion of their time in ECAs have switched to 0.1% marine gasoil when voyaging within ECAs. It is estimated that in 2015, 0.2 mb/d of residual fuel oil bunker demand will switch directly to MGO. The transition is expected to ramp up slowly over the first quarter as vessel owners replenish their fuel tanks. Despite this switch, residual fuel oil will remain the bunker fuel of choice until 2019 as vessels continue to use Bunker C in international waters and MGO only within ECAs.

Most of this switch will take place within Northern Europe and the US. In Europe, most of the switch is expected to take place in the Northwest European bunkering hub of the Amsterdam-Rotterdam-Antwerp (ARA) region with very little change expected in Southern Europe. Additionally, there will be some extra MGO bunkering activity in the Baltic, although this is expected to be significantly less than in ARA. Indeed, at end-2014, Lukoil announced that they would be introducing a new hybrid gasoil/residual fuel oil 0.1% sulphur marine fuel (fuel marine environmental – TSE) available from the Russian port of St Petersburg.

The introduction of a global 0.5% limit of sulphur emissions in 2020 is expected to result in most vessel owners switching to MGO from fuel oil. Nonetheless, scrubbers are expected to become more prevalent. By 2020, the bunker fuel mix is expected to include about 1.0 mb/d of residual fuel oil, 3.1 mb/d of marine gasoil and an equivalent 0.2 mb/d of LNG. This represents 2.2 mb/d of fuel oil demand switching directly to gasoil upon the introduction of the global cap.

**Figure 5.5** Global bunker fuel mix in 2019

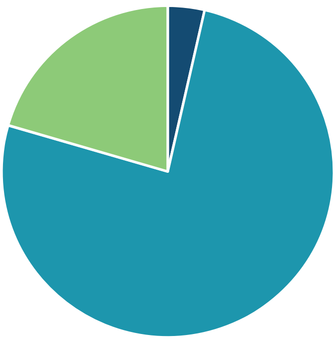
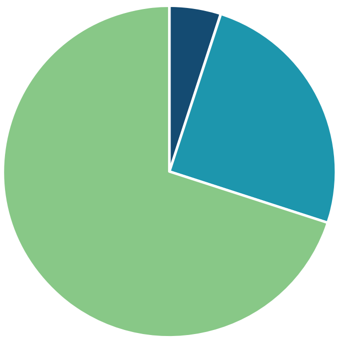


**Figure** 5.6 Global bunker fuel mix in 2020




Against this backdrop, the increase in demand for gasoil from shipping will see total gasoil demand increase by 2.4 mb/d between 2019 and 2020, including continued growth in other sectors. Shipping will account for nearly 10% of total gasoil demand in 2020, a rise of 6.6 percentage points on 2019. On the flipside, global fuel oil demand is set to fall to 5.3 mb/d in 2020, a 2.1 mb/d decrease on 2019.

Although the economics of scrubbers are likely to improve from 2020 onwards, the prevailing market conditions over 2017-19 are expected to be characterised by tightness in fuel oil markets. A number of refiners, notably in the FSU, are scheduled to complete upgrading projects while some simple refinery capacity, notably in Europe and the FSU, will likely be shuttered which will see fuel oil supply curbed while distillate supply is expected to increase. Considering that shipping is a cash-strapped, capital intensive industry, investments in scrubbers may not be made until price signals indicate that fuel oil will be significantly cheaper than gasoil. This could see interest in scrubbers surge upon the introduction of the global cap if gasoil markets were to significantly tighten or fuel oil was to collapse.

### *Impacts upon the product supply chain*

The switch from fuel oil to gasoil in 2020 will require adjustments from the refining industry in order to meet the projected distillate demand and reduce fuel oil output. Investments in upgrading capacity, above and beyond those already announced, would be required to meet the additional 2.2 mb/d of gasoil demand at the end of the forecast. Higher marine demand for middle distillates will also significantly increase distillate cracks and shipping costs. On a global level, very little gasoil (excluding vacuum gasoil oil which is classified here as a fuel oil) is produced with a higher sulphur content than 0.5%. On the flip side, with a significant loosening of fuel oil markets on the horizon, refiners could choose to invest in secondary upgrading units, such as visbreaking, cracking and coking units, to transform fuel oil into more-marketable light and middle distillates. This would essentially see fuel oil move towards becoming a feedstock rather than a 'traditional' refined product.

As discussed in the *Refining and Product Supply* chapter, the main middle-distillate exporting regions in 2020 are expected to be the FSU (with projected net-exports of 1.2 mb/d), OECD Americas (1.1 mb/d) and the Middle East (0.6 mb/d). Despite Other Asia having a large amount of complex refining capacity with high middle-distillate yields, the region is seen flipping to become a net-importer of middle distillates in 2020 on the back of rising distillate demand in Singapore, the world's largest bunker port by volume. The switch will be acutely felt in Europe where the middle-distillate deficit is expected to widen to 1.7 mb/d and require more imports from the FSU, North America and the Middle East.

China is the wild card. While China has turned into a small net exporter of gasoil recently, Chinese refiners have historically scaled both expansions and throughputs to domestic markets, rather than targeting export markets. As refinery projects have been scaled back recently in line with a weaker demand outlook for China, we assume this policy trend to continue in the near term, limiting product exports towards 2020. However, considering that recently-constructed Chinese refineries have high middle distillate yields and are not currently being used to their full-capacity, if refiners did decide to target export markets, they do have the potential to become a significant gasoil exporter.

The midstream sector will also need to adjust to the changes in bunker markets. A significant amount of infrastructure will have to be constructed or reconfigured. Notably, port infrastructure will need to be significantly altered to accommodate rising gasoil volumes. This could include reconfiguring storage capacity, pipelines, pumping equipment and bunker barges to take extra gasoil while jetties and berths may need to be improved to accommodate the larger vessels on which refined products will likely be imported.

# 6. TABLES

## Table 1
## WORLD OIL SUPPLY AND DEMAND
(million barrels per day)

| | 1Q14 | 2Q14 | 3Q14 | 4Q14 | 2014 | 1Q15 | 2Q15 | 3Q15 | 4Q15 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **OECD DEMAND** | | | | | | | | | | | | | | | |
| Americas[1] | 23.9 | 23.6 | 24.2 | 24.6 | 24.1 | 24.1 | 23.9 | 24.4 | 24.5 | 24.2 | 24.3 | 24.4 | 24.5 | 24.4 | 24.4 |
| Europe[2] | 13.0 | 13.4 | 13.9 | 13.3 | 13.4 | 13.0 | 13.3 | 13.7 | 13.4 | 13.3 | 13.3 | 13.2 | 13.1 | 13.0 | 12.9 |
| Asia Oceania[3] | 8.8 | 7.7 | 7.7 | 8.2 | 8.1 | 8.6 | 7.5 | 7.7 | 8.2 | 8.0 | 7.9 | 7.9 | 7.9 | 7.8 | 7.8 |
| Total OECD | 45.7 | 44.7 | 45.8 | 46.2 | 45.6 | 45.6 | 44.7 | 45.8 | 46.1 | 45.6 | 45.5 | 45.5 | 45.5 | 45.3 | 45.1 |
| **NON-OECD DEMAND** | | | | | | | | | | | | | | | |
| FSU | 4.6 | 4.8 | 5.0 | 4.9 | 4.8 | 4.5 | 4.6 | 4.8 | 4.7 | 4.6 | 4.7 | 4.7 | 4.8 | 4.9 | 5.0 |
| Europe | 0.6 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| China | 10.2 | 10.3 | 10.4 | 10.6 | 10.4 | 10.4 | 10.6 | 10.7 | 10.8 | 10.6 | 10.9 | 11.2 | 11.5 | 11.8 | 12.1 |
| Other Asia | 12.2 | 12.2 | 11.9 | 12.3 | 12.1 | 12.6 | 12.5 | 12.3 | 12.7 | 12.5 | 12.9 | 13.3 | 13.7 | 14.1 | 14.5 |
| Latin America | 6.6 | 6.8 | 6.9 | 6.9 | 6.8 | 6.7 | 6.9 | 7.0 | 7.0 | 6.9 | 7.0 | 7.1 | 7.2 | 7.3 | 7.4 |
| Middle East | 7.8 | 8.2 | 8.6 | 7.8 | 8.1 | 8.0 | 8.4 | 8.8 | 8.2 | 8.3 | 8.5 | 8.8 | 9.0 | 9.2 | 9.5 |
| Africa | 3.9 | 3.9 | 3.8 | 4.0 | 3.9 | 4.1 | 4.1 | 4.0 | 4.2 | 4.1 | 4.2 | 4.4 | 4.5 | 4.6 | 4.8 |
| Total Non-OECD | 45.9 | 46.9 | 47.3 | 47.2 | 46.8 | 46.9 | 47.8 | 48.2 | 48.3 | 47.8 | 48.9 | 50.2 | 51.4 | 52.7 | 54.0 |
| **Total Demand[4]** | **91.7** | **91.6** | **93.0** | **93.4** | **92.4** | **92.5** | **92.5** | **94.0** | **94.4** | **93.3** | **94.5** | **95.7** | **96.9** | **98.0** | **99.1** |
| **OECD SUPPLY** | | | | | | | | | | | | | | | |
| Americas[1] | 18.1 | 18.6 | 19.0 | 19.3 | 18.8 | 19.4 | 19.4 | 19.1 | 19.5 | 19.3 | 19.9 | 20.1 | 20.6 | 21.1 | 21.7 |
| Europe[2] | 3.5 | 3.3 | 3.1 | 3.3 | 3.3 | 3.3 | 3.1 | 3.1 | 3.4 | 3.2 | 3.1 | 3.2 | 3.2 | 3.1 | 3.0 |
| Asia Oceania[3] | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.7 | 0.8 | 0.9 | 0.8 |
| Total OECD | 22.1 | 22.4 | 22.6 | 23.2 | 22.6 | 23.2 | 23.0 | 22.7 | 23.4 | 23.1 | 23.6 | 23.9 | 24.5 | 25.0 | 25.6 |
| **NON-OECD SUPPLY** | | | | | | | | | | | | | | | |
| FSU | 14.0 | 13.8 | 13.8 | 13.9 | 13.9 | 14.0 | 13.8 | 13.7 | 13.7 | 13.8 | 13.5 | 13.4 | 13.4 | 13.4 | 13.4 |
| Europe | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| China | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.3 |
| Other Asia[5] | 3.4 | 3.4 | 3.3 | 3.4 | 3.4 | 3.5 | 3.4 | 3.4 | 3.5 | 3.5 | 3.5 | 3.5 | 3.4 | 3.3 | 3.2 |
| Latin America[5,7] | 4.2 | 4.3 | 4.4 | 4.5 | 4.4 | 4.5 | 4.6 | 4.5 | 4.5 | 4.5 | 4.7 | 4.9 | 5.1 | 5.2 | 5.2 |
| Middle East | 1.4 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.2 | 1.2 | 1.2 | 1.2 | 1.1 |
| Africa[5] | 2.4 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.3 | 2.2 |
| Total Non-OECD | 29.8 | 29.5 | 29.5 | 29.7 | 29.6 | 29.8 | 29.7 | 29.5 | 29.6 | 29.7 | 29.5 | 29.7 | 29.7 | 29.7 | 29.5 |
| Processing Gains[6] | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.5 |
| Global Biofuels[7] | 1.7 | 2.3 | 2.5 | 2.2 | 2.2 | 1.9 | 2.3 | 2.6 | 2.3 | 2.3 | 2.3 | 2.3 | 2.4 | 2.4 | 2.4 |
| Total Non-OPEC[5] | 55.7 | 56.4 | 56.9 | 57.4 | 56.6 | 57.2 | 57.3 | 57.2 | 57.6 | 57.3 | 57.8 | 58.3 | 59.0 | 59.5 | 60.0 |
| **OPEC** | | | | | | | | | | | | | | | |
| Crude[8] | 30.0 | 30.1 | 30.5 | 30.5 | 30.3 | | | | | | | | | | |
| OPEC NGLs | 6.3 | 6.3 | 6.4 | 6.5 | 6.4 | 6.5 | 6.6 | 6.6 | 6.6 | 6.6 | 6.8 | 6.9 | 6.9 | 6.9 | 6.9 |
| Total OPEC[5] | 36.3 | 36.4 | 37.0 | 37.0 | 36.7 | | | | | | | | | | |
| **Total Supply[9]** | 92.0 | 92.8 | 93.8 | 94.3 | 93.3 | | | | | | | | | | |
| **Memo items:** | | | | | | | | | | | | | | | |
| Call on OPEC crude + Stock ch.[10] | 29.6 | 28.8 | 29.7 | 29.6 | 29.4 | 28.7 | 28.6 | 30.2 | 30.2 | 29.4 | 29.9 | 30.5 | 31.0 | 31.6 | 32.1 |

1 As of August 2012 OMR, OECD Americas includes Chile.
2 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.
3 As of August 2012 OMR, OECD Asia Oceania includes Israel.
4 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.
5 Other Asia includes Indonesia throughout. Latin America excludes Ecuador throughout. Africa excludes Angola throughout.
Total Non-OPEC excludes all countries that were members of OPEC at 1 January 2009.
Total OPEC comprises all countries which were OPEC members at 1 January 2009.
6 Net volumetric gains and losses in the refining process and marine transportation losses.
7 As of the June 2010 MTOGM, Global Biofuels comprise all world biofuel production including fuel ethanol from the US and Brazil.
8 As of the March 2006 OMR, Venezuelan Orinoco heavy crude production is included within Venezuelan crude estimates. Orimulsion fuel remains within the OPEC NGL & non-conventional category, but Orimulsion production reportedly ceased from January 2007.
9 Comprises crude oil, condensates, NGLs, oil from non-conventional sources and other sources of supply.
10 Equals the arithmetic difference between total demand minus total non-OPEC supply minus OPEC NGLs.

## Table 1a
## WORLD OIL SUPPLY AND DEMAND: CHANGES FROM LAST MEDIUM-TERM REPORT
(million barrels per day)

| | 1Q13 | 2Q13 | 3Q13 | 4Q13 | 2013 | 1Q14 | 2Q14 | 3Q14 | 4Q14 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **OECD DEMAND** | | | | | | | | | | | | | | | |
| Americas | 0.1 | 0.1 | 0.1 | 0.0 | 0.1 | 0.0 | -0.2 | -0.1 | 0.2 | 0.0 | 0.1 | 0.3 | 0.5 | 0.7 | 0.8 |
| Europe | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | -0.1 | -0.2 | 0.0 | -0.4 | -0.2 | -0.2 | -0.3 | -0.3 | -0.3 | -0.4 |
| Asia Oceania | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | 0.0 | -0.2 | -0.3 | -0.2 | -0.2 | -0.2 | -0.2 | -0.2 | -0.2 | -0.2 |
| Total OECD | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 | -0.1 | -0.6 | -0.4 | -0.4 | -0.4 | -0.3 | -0.2 | -0.1 | 0.1 | 0.3 |
| **NON-OECD DEMAND** | | | | | | | | | | | | | | | |
| FSU | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.1 | 0.2 | -0.1 | -0.2 | -0.3 | -0.3 | -0.3 |
| Europe | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| China | -0.1 | 0.1 | 0.0 | 0.1 | 0.0 | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 | -0.3 | -0.4 | -0.5 | -0.5 | -0.5 |
| Other Asia | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.3 |
| Latin America | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 |
| Middle East | -0.1 | -0.1 | -0.1 | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 | -0.2 | -0.1 | -0.2 | -0.3 | -0.4 | -0.4 | -0.6 |
| Africa | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | -0.1 |
| Total Non-OECD | 0.2 | 0.4 | 0.3 | 0.5 | 0.3 | 0.4 | 0.1 | -0.1 | -0.2 | 0.1 | -0.5 | -0.9 | -1.1 | -1.3 | -1.3 |
| **Total Demand** | **0.2** | **0.4** | **0.4** | **0.5** | **0.4** | **0.3** | **-0.5** | **-0.5** | **-0.6** | **-0.3** | **-0.8** | **-1.1** | **-1.1** | **-1.1** | **-1.1** |
| **OECD SUPPLY** | | | | | | | | | | | | | | | |
| Americas | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | 0.4 | 0.6 | 0.5 | 0.3 | 0.2 | 0.0 | -0.3 | -0.4 | -0.2 |
| Europe | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.1 | 0.2 | 0.1 | 0.2 | 0.0 | -0.1 | -0.1 | -0.1 | -0.2 |
| Asia Oceania | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 |
| Total OECD | 0.0 | 0.0 | -0.1 | 0.0 | 0.0 | 0.1 | 0.4 | 0.7 | 0.5 | 0.5 | 0.2 | -0.2 | -0.4 | -0.5 | -0.2 |
| **NON-OECD SUPPLY** | | | | | | | | | | | | | | | |
| FSU | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | 0.0 | 0.1 | 0.0 | 0.0 | -0.3 | -0.4 | -0.5 | -0.6 |
| Europe | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| China | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 |
| Other Asia | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | -0.2 | -0.1 | -0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 |
| Latin America | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.2 | 0.2 | 0.1 | -0.1 | 0.0 | -0.2 | -0.2 | -0.2 |
| Middle East | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | -0.1 | -0.1 |
| Africa | 0.0 | 0.0 | -0.1 | 0.0 | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.2 | -0.3 |
| Total Non-OECD | -0.1 | -0.1 | -0.1 | 0.0 | 0.0 | 0.0 | -0.1 | -0.1 | 0.0 | -0.1 | -0.2 | -0.4 | -0.8 | -1.0 | -1.2 |
| Processing Gains | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Global Biofuels | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.0 | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Non-OPEC | 0.0 | -0.1 | -0.1 | 0.0 | -0.1 | 0.1 | 0.4 | 0.7 | 0.6 | 0.5 | 0.1 | -0.6 | -1.1 | -1.4 | -1.4 |
| **OPEC** | | | | | | | | | | | | | | | |
| Crude | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | | | | | | | | |
| OPEC NGLs | 0.0 | 0.0 | 0.0 | -0.1 | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.2 | -0.2 | -0.2 | -0.2 | -0.2 |
| Total OPEC | 0.0 | 0.0 | 0.0 | -0.1 | 0.0 | -0.1 | | | | | | | | | |
| **Total Supply** | **-0.1** | **-0.1** | **-0.1** | **-0.1** | **-0.1** | **0.0** | | | | | | | | | |
| **Memo items:** | | | | | | | | | | | | | | | |
| Call on OPEC crude + Stock ch. | 0.3 | 0.5 | 0.6 | 0.5 | 0.5 | 0.3 | -0.9 | -1.1 | -1.1 | -0.7 | -0.7 | -0.3 | 0.2 | 0.4 | 0.6 |

## Table 2
## SUMMARY OF GLOBAL OIL DEMAND

| | 1Q14 | 2Q14 | 3Q14 | 4Q14 | 2014 | 1Q15 | 2Q15 | 3Q15 | 4Q15 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Demand (mb/d)** | | | | | | | | | | | | | | | |
| Americas[1] | 23.86 | 23.64 | 24.20 | 24.65 | 24.09 | 24.07 | 23.95 | 24.36 | 24.53 | 24.23 | 24.32 | 24.40 | 24.47 | 24.44 | 24.40 |
| Europe[2] | 13.01 | 13.40 | 13.90 | 13.33 | 13.41 | 12.98 | 13.29 | 13.68 | 13.37 | 13.33 | 13.27 | 13.22 | 13.12 | 13.01 | 12.87 |
| Asia Oceania[3] | 8.85 | 7.65 | 7.67 | 8.24 | 8.10 | 8.56 | 7.45 | 7.72 | 8.24 | 7.99 | 7.94 | 7.90 | 7.87 | 7.84 | 7.81 |
| Total OECD | 45.72 | 44.69 | 45.77 | 46.22 | 45.60 | 45.60 | 44.69 | 45.76 | 46.15 | 45.55 | 45.53 | 45.52 | 45.45 | 45.29 | 45.08 |
| Asia | 22.36 | 22.50 | 22.25 | 22.92 | 22.51 | 23.00 | 23.13 | 22.95 | 23.57 | 23.16 | 23.83 | 24.51 | 25.18 | 25.89 | 26.60 |
| Middle East | 7.81 | 8.20 | 8.56 | 7.84 | 8.10 | 7.95 | 8.38 | 8.79 | 8.16 | 8.32 | 8.55 | 8.78 | 9.01 | 9.25 | 9.47 |
| Latin America | 6.57 | 6.76 | 6.92 | 6.86 | 6.78 | 6.67 | 6.87 | 7.01 | 7.01 | 6.89 | 6.99 | 7.09 | 7.19 | 7.31 | 7.42 |
| FSU | 4.61 | 4.81 | 5.03 | 4.93 | 4.85 | 4.52 | 4.60 | 4.77 | 4.65 | 4.64 | 4.65 | 4.71 | 4.80 | 4.90 | 4.98 |
| Africa | 3.93 | 3.95 | 3.84 | 3.98 | 3.92 | 4.08 | 4.11 | 4.02 | 4.17 | 4.10 | 4.23 | 4.37 | 4.51 | 4.64 | 4.78 |
| Europe | 0.65 | 0.65 | 0.67 | 0.68 | 0.67 | 0.66 | 0.68 | 0.68 | 0.70 | 0.68 | 0.69 | 0.70 | 0.71 | 0.72 | 0.73 |
| Total Non-OECD | 45.93 | 46.87 | 47.28 | 47.21 | 46.82 | 46.88 | 47.76 | 48.22 | 48.26 | 47.79 | 48.94 | 50.16 | 51.41 | 52.71 | 53.98 |
| **World** | **91.65** | **91.56** | **93.05** | **93.42** | **92.43** | **92.48** | **92.45** | **93.98** | **94.40** | **93.34** | **94.47** | **95.68** | **96.87** | **98.00** | **99.05** |
| ***of which:*** | | | | | | | | | | | | | | | |
| *US50* | *18.83* | *18.70* | *19.17* | *19.56* | *19.07* | *19.06* | *19.00* | *19.33* | *19.44* | *19.21* | *19.31* | *19.39* | *19.47* | *19.45* | *19.43* |
| *Euro5* | *7.89* | *7.93* | *8.26* | *7.94* | *8.01* | *7.89* | *7.89* | *8.05* | *7.89* | *7.93* | *7.85* | *7.77* | *7.69* | *7.60* | *7.49* |
| *China* | *10.15* | *10.32* | *10.39* | *10.63* | *10.37* | *10.42* | *10.59* | *10.68* | *10.83* | *10.63* | *10.92* | *11.22* | *11.51* | *11.81* | *12.10* |
| *Japan* | *5.02* | *3.87* | *3.88* | *4.37* | *4.28* | *4.67* | *3.73* | *3.90* | *4.31* | *4.15* | *4.09* | *4.04* | *4.00* | *3.96* | *3.92* |
| *India* | *3.96* | *3.96* | *3.68* | *3.87* | *3.87* | *4.06* | *4.10* | *3.82* | *4.05* | *4.01* | *4.15* | *4.31* | *4.46* | *4.59* | *4.73* |
| *Russia* | *3.47* | *3.60* | *3.78* | *3.60* | *3.61* | *3.39* | *3.41* | *3.55* | *3.38* | *3.43* | *3.45* | *3.50* | *3.58* | *3.66* | *3.73* |
| *Brazil* | *3.10* | *3.16* | *3.27* | *3.26* | *3.20* | *3.16* | *3.26* | *3.35* | *3.36* | *3.28* | *3.33* | *3.38* | *3.43* | *3.49* | *3.54* |
| *Saudi Arabia* | *2.86* | *3.30* | *3.56* | *2.97* | *3.17* | *2.98* | *3.39* | *3.65* | *3.11* | *3.29* | *3.40* | *3.51* | *3.60* | *3.68* | *3.75* |
| *Korea* | *2.36* | *2.32* | *2.33* | *2.37* | *2.35* | *2.40* | *2.25* | *2.34* | *2.42* | *2.35* | *2.36* | *2.37* | *2.37* | *2.38* | *2.38* |
| *Canada* | *2.43* | *2.34* | *2.45* | *2.46* | *2.42* | *2.40* | *2.36* | *2.44* | *2.42* | *2.41* | *2.38* | *2.35* | *2.33* | *2.30* | *2.28* |
| *Mexico* | *1.95* | *1.97* | *1.96* | *1.98* | *1.97* | *1.94* | *1.97* | *1.96* | *2.02* | *1.97* | *1.99* | *2.00* | *2.00* | *2.01* | *2.02* |
| *Iran* | *1.84* | *1.79* | *1.81* | *1.81* | *1.81* | *1.86* | *1.85* | *1.85* | *1.86* | *1.85* | *1.90* | *1.95* | *1.99* | *2.03* | *2.06* |
| *Total* | *63.85* | *63.28* | *64.54* | *64.83* | *64.13* | *64.24* | *63.80* | *64.91* | *65.08* | *64.51* | *65.12* | *65.79* | *66.43* | *66.95* | *67.42* |
| *% of World* | *69.67* | *69.11* | *69.36* | *69.40* | *69.38* | *69.46* | *69.00* | *69.07* | *68.94* | *69.12* | *68.93* | *68.76* | *68.58* | *68.32* | *68.07* |
| **Annual Change (% per annum)** | | | | | | | | | | | | | | | |
| Americas[1] | 0.3 | -1.0 | -0.5 | 1.2 | 0.0 | 0.8 | 1.3 | 0.7 | -0.5 | 0.6 | 0.4 | 0.3 | 0.3 | -0.1 | -0.2 |
| Europe[2] | -1.4 | -3.3 | -0.9 | -2.1 | -1.9 | -0.3 | -0.9 | -1.5 | 0.3 | -0.6 | -0.4 | -0.4 | -0.8 | -0.8 | -1.1 |
| Asia Oceania[3] | -0.2 | -2.3 | -4.3 | -4.3 | -2.7 | -3.3 | -2.6 | 0.6 | 0.0 | -1.4 | -0.7 | -0.5 | -0.4 | -0.4 | -0.4 |
| Total OECD | -0.28 | -1.92 | -1.29 | -0.76 | -1.06 | -0.27 | -0.01 | -0.01 | -0.16 | -0.11 | -0.05 | -0.03 | -0.14 | -0.35 | -0.48 |
| Asia | 2.5 | 2.4 | 2.4 | 2.6 | 2.5 | 2.8 | 2.8 | 3.1 | 2.9 | 2.9 | 2.9 | 2.9 | 2.7 | 2.8 | 2.7 |
| Middle East | 3.5 | 3.2 | 2.0 | 1.2 | 2.5 | 1.9 | 2.2 | 2.6 | 4.1 | 2.7 | 2.7 | 2.7 | 2.7 | 2.6 | 2.4 |
| Latin America | 3.3 | 2.5 | 2.4 | 1.3 | 2.3 | 1.4 | 1.6 | 1.4 | 2.2 | 1.7 | 1.4 | 1.4 | 1.5 | 1.6 | 1.5 |
| FSU | 3.3 | 3.6 | 2.1 | 0.0 | 2.2 | -1.9 | -4.4 | -5.1 | -5.6 | -4.3 | 0.4 | 1.3 | 1.9 | 2.0 | 1.7 |
| Africa | 0.9 | 1.6 | 3.2 | 4.2 | 2.5 | 3.8 | 4.1 | 4.7 | 4.9 | 4.4 | 3.4 | 3.2 | 3.2 | 2.9 | 2.8 |
| Europe | 5.2 | 0.9 | 2.4 | 1.1 | 2.4 | 2.4 | 3.8 | 0.8 | 1.8 | 2.1 | 1.6 | 1.6 | 1.5 | 1.4 | 1.3 |
| Total Non-OECD | 2.8 | 2.6 | 2.4 | 2.0 | 2.4 | 2.1 | 1.9 | 2.0 | 2.2 | 2.1 | 2.4 | 2.5 | 2.5 | 2.5 | 2.4 |
| **World** | **1.2** | **0.3** | **0.5** | **0.6** | **0.7** | **0.9** | **1.0** | **1.0** | **1.0** | **1.0** | **1.2** | **1.3** | **1.2** | **1.2** | **1.1** |
| **Annual Change (mb/d)** | | | | | | | | | | | | | | | |
| Americas[1] | 0.07 | -0.23 | -0.12 | 0.30 | 0.00 | 0.20 | 0.31 | 0.16 | -0.11 | 0.14 | 0.09 | 0.08 | 0.07 | -0.03 | -0.04 |
| Europe[2] | -0.18 | -0.46 | -0.12 | -0.29 | -0.26 | -0.04 | -0.12 | -0.21 | 0.04 | -0.08 | -0.06 | -0.05 | -0.10 | -0.10 | -0.14 |
| Asia Oceania[3] | -0.01 | -0.18 | -0.35 | -0.37 | -0.23 | -0.29 | -0.20 | 0.05 | 0.00 | -0.11 | -0.05 | -0.04 | -0.03 | -0.03 | -0.03 |
| Total OECD | -0.13 | -0.88 | -0.60 | -0.35 | -0.49 | -0.12 | 0.00 | 0.00 | -0.07 | -0.05 | -0.02 | -0.01 | -0.06 | -0.16 | -0.22 |
| Asia | 0.54 | 0.52 | 0.52 | 0.59 | 0.54 | 0.63 | 0.63 | 0.69 | 0.65 | 0.65 | 0.66 | 0.68 | 0.67 | 0.71 | 0.71 |
| Middle East | 0.27 | 0.26 | 0.17 | 0.10 | 0.20 | 0.14 | 0.18 | 0.23 | 0.32 | 0.22 | 0.22 | 0.23 | 0.23 | 0.23 | 0.22 |
| Latin America | 0.21 | 0.16 | 0.16 | 0.08 | 0.15 | 0.09 | 0.11 | 0.09 | 0.15 | 0.11 | 0.10 | 0.10 | 0.11 | 0.11 | 0.11 |
| FSU | 0.15 | 0.17 | 0.10 | 0.00 | 0.10 | -0.09 | -0.21 | -0.26 | -0.28 | -0.21 | 0.02 | 0.06 | 0.09 | 0.10 | 0.08 |
| Africa | 0.04 | 0.06 | 0.12 | 0.16 | 0.09 | 0.15 | 0.16 | 0.18 | 0.19 | 0.17 | 0.14 | 0.14 | 0.14 | 0.13 | 0.13 |
| Europe | 0.03 | 0.01 | 0.02 | 0.01 | 0.02 | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Total Non-OECD | 1.23 | 1.18 | 1.09 | 0.94 | 1.11 | 0.95 | 0.90 | 0.94 | 1.05 | 0.96 | 1.15 | 1.22 | 1.25 | 1.30 | 1.26 |
| **World** | **1.10** | **0.30** | **0.49** | **0.58** | **0.62** | **0.83** | **0.89** | **0.94** | **0.98** | **0.91** | **1.13** | **1.21** | **1.19** | **1.14** | **1.05** |
| **Revisions to Oil Demand from Last Medium Term Report (mb/d)** | | | | | | | | | | | | | | | |
| Americas[1] | 0.04 | -0.23 | -0.10 | 0.22 | -0.02 | 0.08 | 0.03 | 0.12 | 0.26 | 0.12 | 0.29 | 0.47 | 0.66 | 0.83 | |
| Europe[2] | -0.07 | -0.21 | -0.04 | -0.42 | -0.18 | -0.39 | -0.34 | -0.19 | -0.08 | -0.25 | -0.30 | -0.31 | -0.33 | -0.36 | |
| Asia Oceania[3] | -0.04 | -0.16 | -0.30 | -0.21 | -0.18 | -0.16 | -0.18 | -0.26 | -0.26 | -0.21 | -0.21 | -0.21 | -0.22 | -0.22 | |
| Total OECD | -0.07 | -0.60 | -0.44 | -0.41 | -0.38 | -0.47 | -0.48 | -0.33 | -0.08 | -0.34 | -0.22 | -0.06 | 0.12 | 0.25 | |
| Asia | 0.16 | -0.05 | -0.07 | -0.04 | 0.00 | -0.24 | -0.13 | -0.09 | -0.21 | -0.17 | -0.27 | -0.31 | -0.31 | -0.18 | |
| Middle East | -0.05 | -0.08 | -0.14 | -0.20 | -0.12 | -0.10 | -0.12 | -0.22 | -0.20 | -0.16 | -0.28 | -0.36 | -0.45 | -0.56 | |
| Latin America | 0.01 | 0.03 | 0.03 | -0.02 | 0.01 | -0.01 | 0.00 | -0.05 | -0.06 | -0.03 | -0.06 | -0.08 | -0.10 | -0.11 | |
| FSU | 0.18 | 0.21 | 0.17 | 0.08 | 0.16 | 0.04 | -0.08 | -0.19 | -0.30 | -0.13 | -0.22 | -0.25 | -0.29 | -0.31 | |
| Africa | 0.10 | 0.02 | -0.03 | -0.01 | 0.02 | -0.03 | 0.02 | 0.02 | 0.05 | 0.01 | -0.01 | -0.05 | -0.08 | -0.11 | |
| Europe | -0.02 | -0.04 | -0.01 | -0.02 | -0.02 | -0.02 | -0.02 | -0.02 | -0.02 | -0.02 | -0.03 | -0.03 | -0.04 | -0.04 | |
| Total Non-OECD | 0.38 | 0.09 | -0.06 | -0.20 | 0.05 | -0.36 | -0.34 | -0.55 | -0.73 | -0.50 | -0.86 | -1.08 | -1.26 | -1.31 | |
| **World** | **0.31** | **-0.51** | **-0.50** | **-0.61** | **-0.33** | **-0.83** | **-0.83** | **-0.88** | **-0.82** | **-0.84** | **-1.08** | **-1.14** | **-1.14** | **-1.06** | |
| **Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)** | | | | | | | | | | | | | | | |
| World | 0.13 | -0.01 | -0.36 | -0.45 | -0.20 | 0.03 | -0.33 | -0.56 | -0.41 | -0.32 | -0.19 | -0.05 | -0.02 | 0.04 | |

1 As of the August 2012 OMR, includes Chile.
2 As of the August 2012 OMR, includes Estonia and Slovenia.
3 As of the August 2012 OMR, includes Israel.
* France, Germany, Italy, Spain and UK

# Table 3
## WORLD OIL PRODUCTION
(million barrels per day)

| | 1Q14 | 2Q14 | 3Q14 | 4Q14 | 2014 | 1Q15 | 2Q15 | 3Q15 | 4Q15 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **OPEC** | | | | | | | | | | | | | | | |
| Crude Oil | | | | | | | | | | | | | | | |
| Saudi Arabia | 9.46 | 9.50 | 9.62 | 9.53 | 9.53 | | | | | | | | | | |
| Iran | 2.82 | 2.84 | 2.79 | 2.80 | 2.81 | | | | | | | | | | |
| Iraq | 3.29 | 3.33 | 3.21 | 3.48 | 3.33 | | | | | | | | | | |
| UAE | 2.73 | 2.74 | 2.81 | 2.74 | 2.75 | | | | | | | | | | |
| Kuwait | 2.53 | 2.58 | 2.65 | 2.67 | 2.61 | | | | | | | | | | |
| Neutral Zone | 0.52 | 0.43 | 0.38 | 0.21 | 0.38 | | | | | | | | | | |
| Qatar | 0.72 | 0.71 | 0.72 | 0.68 | 0.71 | | | | | | | | | | |
| Angola | 1.57 | 1.63 | 1.71 | 1.72 | 1.66 | | | | | | | | | | |
| Nigeria | 1.93 | 1.91 | 1.89 | 1.89 | 1.91 | | | | | | | | | | |
| Libya | 0.37 | 0.23 | 0.57 | 0.67 | 0.46 | | | | | | | | | | |
| Algeria | 1.07 | 1.14 | 1.15 | 1.13 | 1.12 | | | | | | | | | | |
| Ecuador | 0.55 | 0.55 | 0.56 | 0.55 | 0.55 | | | | | | | | | | |
| Venezuela | 2.45 | 2.48 | 2.48 | 2.44 | 2.46 | | | | | | | | | | |
| Total Crude Oil | 30.00 | 30.08 | 30.52 | 30.50 | 30.28 | | | | | | | | | | |
| Total NGLs[1] | 6.31 | 6.34 | 6.45 | 6.47 | 6.39 | 6.54 | 6.59 | 6.59 | 6.62 | 6.58 | 6.82 | 6.88 | 6.89 | 6.91 | 6.93 |
| **Total OPEC[2]** | **36.32** | **36.42** | **36.97** | **36.97** | **36.67** | | | | | | | | | | |
| **NON-OPEC[3]** | | | | | | | | | | | | | | | |
| **OECD** | | | | | | | | | | | | | | | |
| **Americas[7]** | 18.07 | 18.62 | 18.99 | 19.35 | 18.76 | 19.44 | 19.42 | 19.06 | 19.48 | 19.35 | 19.89 | 20.12 | 20.56 | 21.07 | 21.73 |
| United States[6] | 10.96 | 11.69 | 12.11 | 12.44 | 11.81 | 12.43 | 12.52 | 12.30 | 12.45 | 12.42 | 12.89 | 13.06 | 13.37 | 13.66 | 13.96 |
| Mexico | 2.87 | 2.85 | 2.76 | 2.66 | 2.78 | 2.67 | 2.64 | 2.59 | 2.59 | 2.62 | 2.62 | 2.61 | 2.61 | 2.67 | 2.79 |
| Canada | 4.23 | 4.08 | 4.10 | 4.24 | 4.16 | 4.33 | 4.25 | 4.16 | 4.43 | 4.29 | 4.37 | 4.45 | 4.58 | 4.73 | 4.98 |
| Chile | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| **Europe[8]** | 3.51 | 3.25 | 3.14 | 3.34 | 3.31 | 3.29 | 3.11 | 3.08 | 3.41 | 3.22 | 3.14 | 3.17 | 3.16 | 3.09 | 3.03 |
| UK | 0.98 | 0.90 | 0.71 | 0.84 | 0.86 | 0.84 | 0.81 | 0.73 | 0.93 | 0.83 | 0.83 | 0.83 | 0.84 | 0.83 | 0.83 |
| Norway | 1.96 | 1.79 | 1.86 | 1.91 | 1.88 | 1.90 | 1.77 | 1.81 | 1.93 | 1.85 | 1.77 | 1.77 | 1.76 | 1.72 | 1.70 |
| Others | 0.57 | 0.55 | 0.58 | 0.59 | 0.57 | 0.55 | 0.53 | 0.54 | 0.56 | 0.54 | 0.54 | 0.56 | 0.56 | 0.53 | 0.51 |
| **Asia Oceania[9]** | 0.49 | 0.49 | 0.51 | 0.52 | 0.50 | 0.52 | 0.51 | 0.52 | 0.52 | 0.52 | 0.58 | 0.66 | 0.82 | 0.88 | 0.83 |
| Australia | 0.41 | 0.41 | 0.43 | 0.44 | 0.42 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.49 | 0.57 | 0.73 | 0.79 | 0.75 |
| Others | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 | 0.09 | 0.09 | 0.09 | 0.09 | 0.08 |
| Total OECD | 22.07 | 22.37 | 22.64 | 23.21 | 22.57 | 23.24 | 23.04 | 22.66 | 23.41 | 23.09 | 23.61 | 23.95 | 24.53 | 25.03 | 25.59 |
| **NON-OECD** | | | | | | | | | | | | | | | |
| **Former USSR** | 14.01 | 13.84 | 13.81 | 13.93 | 13.90 | 13.96 | 13.82 | 13.68 | 13.68 | 13.78 | 13.52 | 13.42 | 13.40 | 13.44 | 13.38 |
| Russia | 10.99 | 10.92 | 10.84 | 10.97 | 10.93 | 10.92 | 10.83 | 10.69 | 10.69 | 10.78 | 10.65 | 10.59 | 10.55 | 10.45 | 10.37 |
| Others | 3.02 | 2.91 | 2.97 | 2.97 | 2.97 | 3.04 | 2.99 | 2.99 | 2.99 | 3.00 | 2.86 | 2.82 | 2.85 | 3.00 | 3.01 |
| **Asia** | 7.68 | 7.65 | 7.50 | 7.53 | 7.59 | 7.65 | 7.64 | 7.63 | 7.73 | 7.66 | 7.68 | 7.64 | 7.59 | 7.52 | 7.52 |
| China | 4.23 | 4.23 | 4.17 | 4.15 | 4.20 | 4.19 | 4.20 | 4.18 | 4.24 | 4.20 | 4.19 | 4.18 | 4.18 | 4.21 | 4.29 |
| Malaysia | 0.66 | 0.66 | 0.63 | 0.67 | 0.66 | 0.69 | 0.69 | 0.69 | 0.70 | 0.69 | 0.73 | 0.73 | 0.73 | 0.73 | 0.74 |
| India | 0.88 | 0.87 | 0.86 | 0.88 | 0.87 | 0.89 | 0.89 | 0.89 | 0.89 | 0.89 | 0.87 | 0.84 | 0.81 | 0.78 | 0.77 |
| Indonesia | 0.84 | 0.84 | 0.83 | 0.81 | 0.83 | 0.81 | 0.77 | 0.77 | 0.80 | 0.79 | 0.85 | 0.84 | 0.81 | 0.76 | 0.72 |
| Others | 1.07 | 1.04 | 1.02 | 1.02 | 1.04 | 1.07 | 1.08 | 1.09 | 1.10 | 1.09 | 1.06 | 1.06 | 1.06 | 1.03 | 1.00 |
| **Europe** | 0.14 | 0.14 | 0.14 | 0.13 | 0.14 | 0.14 | 0.13 | 0.13 | 0.13 | 0.13 | 0.12 | 0.11 | 0.10 | 0.09 | 0.08 |
| **Latin America** | 4.22 | 4.28 | 4.43 | 4.52 | 4.37 | 4.45 | 4.55 | 4.52 | 4.54 | 4.52 | 4.68 | 4.88 | 5.06 | 5.17 | 5.21 |
| Brazil[6] | 2.18 | 2.28 | 2.39 | 2.47 | 2.33 | 2.46 | 2.56 | 2.54 | 2.56 | 2.53 | 2.70 | 2.87 | 3.03 | 3.14 | 3.21 |
| Argentina | 0.63 | 0.62 | 0.62 | 0.62 | 0.62 | 0.64 | 0.63 | 0.63 | 0.63 | 0.63 | 0.65 | 0.69 | 0.73 | 0.74 | 0.75 |
| Colombia | 1.00 | 0.97 | 1.00 | 1.00 | 0.99 | 0.94 | 0.94 | 0.93 | 0.92 | 0.93 | 0.86 | 0.85 | 0.85 | 0.85 | 0.84 |
| Others | 0.41 | 0.42 | 0.42 | 0.42 | 0.42 | 0.42 | 0.42 | 0.42 | 0.43 | 0.42 | 0.47 | 0.47 | 0.45 | 0.43 | 0.41 |
| **Middle East[4]** | 1.35 | 1.32 | 1.31 | 1.29 | 1.32 | 1.30 | 1.29 | 1.28 | 1.27 | 1.28 | 1.22 | 1.19 | 1.16 | 1.15 | 1.13 |
| Oman | 0.96 | 0.95 | 0.95 | 0.94 | 0.95 | 0.96 | 0.95 | 0.94 | 0.94 | 0.95 | 0.91 | 0.90 | 0.89 | 0.89 | 0.88 |
| Syria | 0.03 | 0.03 | 0.04 | 0.04 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 | 0.02 | 0.02 |
| Yemen | 0.17 | 0.15 | 0.13 | 0.13 | 0.15 | 0.13 | 0.12 | 0.11 | 0.11 | 0.12 | 0.11 | 0.09 | 0.09 | 0.08 | 0.08 |
| Others | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.20 | 0.19 | 0.18 | 0.17 | 0.16 | 0.16 | 0.15 |
| **Africa** | 2.36 | 2.31 | 2.30 | 2.30 | 2.32 | 2.34 | 2.31 | 2.30 | 2.28 | 2.31 | 2.32 | 2.42 | 2.37 | 2.31 | 2.19 |
| Egypt | 0.72 | 0.70 | 0.69 | 0.68 | 0.70 | 0.68 | 0.67 | 0.66 | 0.65 | 0.66 | 0.66 | 0.62 | 0.59 | 0.56 | 0.54 |
| Equatorial Guinea | 0.28 | 0.27 | 0.28 | 0.29 | 0.28 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.27 | 0.24 | 0.22 | 0.20 |
| Sudan | 0.11 | 0.11 | 0.11 | 0.10 | 0.11 | 0.10 | 0.10 | 0.09 | 0.09 | 0.09 | 0.09 | 0.08 | 0.08 | 0.07 | 0.07 |
| Others | 1.24 | 1.22 | 1.22 | 1.23 | 1.23 | 1.27 | 1.26 | 1.26 | 1.26 | 1.26 | 1.28 | 1.45 | 1.46 | 1.47 | 1.38 |
| Total Non-OECD | 29.75 | 29.54 | 29.50 | 29.72 | 29.63 | 29.83 | 29.74 | 29.54 | 29.63 | 29.68 | 29.54 | 29.66 | 29.68 | 29.68 | 29.52 |
| Processing Gains[5] | 2.21 | 2.19 | 2.24 | 2.22 | 2.21 | 2.29 | 2.27 | 2.32 | 2.29 | 2.29 | 2.33 | 2.33 | 2.38 | 2.43 | 2.48 |
| Global Biofuels[6] | 1.68 | 2.29 | 2.50 | 2.22 | 2.18 | 1.85 | 2.25 | 2.63 | 2.29 | 2.26 | 2.29 | 2.32 | 2.36 | 2.38 | 2.41 |
| **TOTAL NON-OPEC[2]** | **55.71** | **56.38** | **56.88** | **57.36** | **56.59** | **57.22** | **57.31** | **57.15** | **57.62** | **57.32** | **57.78** | **58.26** | **58.96** | **59.52** | **60.00** |
| **TOTAL SUPPLY** | **92.03** | **92.80** | **93.85** | **94.33** | **93.26** | | | | | | | | | | |

1 Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. Venezuelan Orimulsion (but not Orinoco extra-heavy oil), and non-oil inputs to Saudi Arabian MTBE. Orimulsion production reportedly ceased from January 2007.
2 Total OPEC comprises all countries which were OPEC members at 1 January 2009.
Total Non-OPEC excludes all countries that were OPEC members at 1 January 2009.
3 Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
4 Includes small amounts of production from Jordan and Bahrain.
5 Net volumetric gains and losses in refining and marine transportation losses.
6 As of the June 2010 MTOGM, Global Biofuels comprise all world biofuel production including fuel ethanol from the US and Brazil.
7 As of the August 2012 OMR, includes Chile.
8 As of the August 2012 OMR, includes Estonia and Slovenia.
9 As of the August 2012 OMR, includes Israel.

## Table 3a
## SELECTED NON-OPEC UPSTREAM PROJECT START-UPS

| Country | Project | Peak Capacity (kbd) | Start Year | Country | Project | Peak Capacity (kbd) | Start Year | Country | Project | Peak Capacity (kbd) | Start Year |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ***OECD Americas*** | | | | ***OECD Europe*** | | | | | | | |
| USA | Jack/St Malo | 170 | 2014 | Denmark | Hejre | 35 | 2017 | Russia | Tsentralnoye | 100 | 2017 |
| USA | Lucius | 80 | 2014 | Norway | Gudrun/Sigrun | 70 | 2014 | Russia | Yurubcheno-Tokhomskoye | 100 | 2017 |
| USA | Mars B (Olympus) | 100 | 2014 | Norway | Knarr (Jordbaer) | 60 | 2014 | Russia | Bazhenov layer (incl Priobskoye) | 200 | 2018-20 |
| USA | Tubular Bells (Gulfstar) | 60 | 2014 | Norway | Ekofisk extension | 50 | 2015 | Russia | Kuyumba | 230 | 2018 |
| USA | Big Foot | 75 | 2015 | Norway | Eldfish extension | 20 | 2015 | Russia | Tagulskoye | 90 | 2019 |
| USA | Gunflint/Freedom | 120 | 2015 | Norway | Goliat | 70 | 2015 | Russia | Naulskoye | 80 | 2020 |
| USA | Julia | 34 | 2016 | Norway | Edvard Grieg | 90 | 2015 | Russia | Gazprom Condensate | 170 | ongoing |
| USA | Stones | 50 | 2016 | Norway | Luno | 45 | 2016 | Kazakhstan | Kashagan phase 1a (restart) | 375 | 2017 |
| USA | Heidelberg | 80 | 2017 | Norway | Martin Linge | 45 | 2016 | Kazakhstan | Karachaganak phase 3 | 60 | 2019 |
| USA | Vito | 90 | 2017 | Norway | Nona | 15 | 2017 | Azerbaijan | West Chirag Oil | 150 | 2014 |
| USA | Kaskida | 100 | 2020 | Norway | Gina Krog | 70 | 2017 | Azerbaijan | Shah-Deniz 2 | 150 | 2019 |
| USA | Mad Dog 2 | 130 | 2020 | Norway | Aasta Hansteen | 20 | 2017 | ***Asia*** | | | |
| Canada | Jackfish phase 3 | 35 | 2014 | Norway | Ivar Aasen | 100 | 2018 | India | Krishna-Godavari | 80 | 2017 |
| Canada | Algar Lake | 6 | 2014 | Norway | Njord | 50 | 2019 | India | Vasai West and Bombay High redev. | 100 | 2017 |
| Canada | Foster Creek F | 45 | 2014 | Norway | Hod | 22 | 2020 | India | Rajasthan Block: Mangala, Aishwariya, Bhagyam | 150 | ongoing |
| Canada | Hangingstone phase 1 | 12 | 2015 | Norway | Johan Sverdrup | 315 | 2020 | Indonesia | Banyu Urip (full field) | 165 | 2015 |
| Canada | Firebag | 180 | 2014 | Norway | Sleipner extension | 80 | 2020 | Indonesia | Gendalo Gehem | 50 | 2017 |
| Canada | Sunrise phase 1 | 60 | 2014 | UK | Huntington | 60 | 2014 | Malaysia | Kebabangan | 40 | 2014 |
| Canada | Black Gold phase 1 | 10 | 2015 | UK | Breagh | 30 | 2014 | Malaysia | Kasawari | 30 | 2018 |
| Canada | Foster Creek G | 40 | 2015 | UK | Laggan-Tormore | 20 | 2015 | Thailand | Ubon | 30 | 2019 |
| Canada | Cold Lake phases 14-16 (Nabiye) | 40 | 2015 | UK | Golden Eagle | 65 | 2014 | Viet Nam | Sutu Nau | 45 | 2015 |
| Canada | Kearl Phase 2 | 110 | 2015 | UK | Morrone | 15 | 2014 | ***Latin America*** | | | |
| Canada | Horizon phase 2A | 10 | 2015 | UK | Monarb | 50 | 2015 | Brazil | Cidade de Ilhabela FPSO (Sapinhoá) | 150 | 2014 |
| Canada | Surmont phase 2 | 109 | 2015 | UK | Alma/Galia | 20 | 2015 | Brazil | Cidade de Mangaratiba FPSO | 150 | 2014 |
| Canada | Rush Lake | 10 | 2015 | UK | Western Isles | 35 | 2016 | Brazil | Papa Terra P-61 | 100 | 2014 |
| Canada | Edam East | 10 | 2016 | UK | Cheviot (former Emerald) | 25 | 2016 | Brazil | Roncador P-62 | 180 | 2014 |
| Canada | Christina Lake 3A | 50 | 2016 | UK | Schiehallion Redevelopment/Quad 204 | 150 | 2017 | Brazil | Cidade de Itaguaí FPSO (Iracema Norte) | 150 | 2015 |
| Canada | Christina Lake F | 50 | 2016 | UK | Clair expansion | 90 | 2017 | Brazil | Atlanta EPS | 15 | 2016 |
| Canada | Aurora South Train 1 | 100 | 2016 | UK | Mariner | 75 | 2018 | Brazil | Lapa (Carioca) North (pre-salt) | 80 | 2017 |
| Canada | Dover North phase 1 | 50 | 2016 | UK | Fyne | 25 | 2019 | Brazil | Lula (Central and Sul) | 275 | 2017 |
| Canada | Foster Creek H | 40 | 2016 | UK | North West Hutton Redevelopment | 100 | 2020 | Brazil | Buzios (Franco) all phases | 500 | 2018 |
| Canada | Kirby North Phase 1 | 40 | 2016 | UK | Monarb Redevelopment | 50 | 2020 | Brazil | Iara Horst | 140 | 2018 |
| Canada | Edam East | 10 | 2016 | ***OECD Asia Oceania*** | | | | Brazil | Tartaruga Verde | 100 | 2018 |
| Canada | Edam West | 5 | 2016 | Australia | North Rankin and Gorgon Liquids | 80 | 2015 | Brazil | Sepia | 250 | 2020 |
| Canada | Vawn | 10 | 2016 | Australia | Ichthys | 130 | 2017 | Colombia | Guairuro | 15 | 2016 |
| Canada | Horizon phase 2B | 45 | 2017 | Australia | Prelude | 45 | 2017 | Colombia | Block CPO 14 | 20 | 2019 |
| Canada | White Rose Extension Project | 50 | 2018 | ***FSU*** | | | | ***Middle East*** | | | |
| Canada | Grouse | 50 | 2018 | Russia | Imilorskoye | 60 | 2014 | Oman | Harweel and other PDO EOR | 40 | ongoing |
| Canada | McMullen | 10 | 2020 | Russia | Arkutun-Daginskoye | 90 | 2014 | ***Africa*** | | | |
| Mexico | Ayatsil-Tekel | 300 | 2014-2016 | Russia | Termokarstovoye | 25 | 2015 | Congo | Moho North | 125 | 2016 |
| Mexico | Tsimin-Xux | 144 | 2015 | Russia | Trebs and Titov | 120 | 2016 | Ghana | Tweneboa-Enyera-Ntomme | 45 | 2016 |
| Mexico | Onel | 15 | 2016 | Russia | Vladimir Filanovsky | 150 | 2016 | Ghana | Sankofa-Gye Nyame | 60 | 2017 |
| Mexico | Navegante | 15 | 2018 | Russia | Chayadinskoye (all phases) | 50 | 2017 | Ivory Coast | Acajou | 10 | 2017 |
| Mexico | Chicontepec Expansion | 15 | ongoing | Russia | Novoportovskoye | 200 | 2017 | Uganda | Albert Basin (Kingfisher) | 35 | 2019 |

## Table 3b

## SELECTED OPEC UPSTREAM PROJECT START-UPS

| Country | Project | Peak Capacity (kbd) | Start Year | Country | Project | Peak Capacity (kbd) | Start Year |
|---|---|---|---|---|---|---|---|
| ***Crude Oil Projects*** | | | | | | | |
| Angola | CLOV (Block 17) | 160 | 2014 | Nigeria | Egina | 200 | 2020 |
| Angola | Mafumeira Sul (Block 0) | 110 | 2015 | Saudi Arabia | Manifa 2 | 400 | 2014 |
| Angola | Cinguvu\Nzanza | 20 | 2015 | Saudi Arabia | Shaybah Expansion | 250 | 2016 |
| Angola | Lianzi (Congo-Brazzaville joint zone) | 23 | 2015 | Saudi Arabia | Khurais Expansion | 300 | 2017 |
| Angola | Sangos/N'Goma (Block 15) | 40 | 2015 | UAE | Umm al Lulu | 105 | 2014 |
| Angola | Cabaca Norte-1(Block 15) | 40 | 2016 | UAE | Upper Zakum expansion | 200 | 2014 |
| Angola | Cabaca SE | 40 | 2016 | UAE | Nasr | 65 | 2015 |
| Angola | Kaombo (Gindunga, Canela, Gengibre) (Central SE Zone) | 200 | 2017 | UAE | Satah al Razboot (SARB) | 100 | 2019 |
| Angola | Mostrado, Cola, Salsa, Manjericao (Block 32) | 80 | 2017 | Venezuela | Carabobo 3 | 100 | 2016 |
| Angola | Chissonga (Block 16) | 100 | 2018 | Venezuela | PetroVictoria (Rosneft) | 200 | 2017 |
| Angola | Malange | 50 | 2019 | | | | |
| Ecuador | Pungarayacu--Phase 1 | 30 | 2017 | ***NGL & Condensate Projects*** | | | |
| Ecuador | ITT (Ishpingo-Tambococha-Tiputini) | 160 | 2017 | Angola | Mafumeira Sul Phase 2 | 10 | 2015 |
| Ecuador | Pungarayacu--Phase 2 | 30 | 2019 | Iran | South Pars 12 (condensate) | 75 | 2014 |
| Iran | Azadegan 2 North | 75 | 2016 | Iran | South Pars 12 (NGLs) | 30 | 2014 |
| Iran | South Pars | 35 | 2017 | Iran | Kharg NGL | 20 | 2015 |
| Iran | Bahregansar | 65 | 2019 | Iran | South Pars 15-16 (condensate) | 80 | 2018 |
| Kuwait | Ratqa | 60 | 2018 | Iran | Pars 15 & 16 (NGLs) | 28 | 2018 |
| Nigeria | Erha North 2 | 50 | 2016 | Nigeria | Gbaran/Ubie | 20 | 2017 |
| Nigeria | Bonga NW | 45 | 2016 | Qatar | Barzan (condensate) | 50 | 2015 |
| Nigeria | Zabazaba/Etan | 120 | 2017 | Saudi | Shaybah NGL | 240 | 2014 |
| Nigeria | Bonga SW & Aparo | 225 | 2018 | Saudi | Hasbah (Wasit) | 30 | 2014 |
| Nigeria | Etim/Asasa | 60 | 2016 | UAE | Shah Sour Gas (NGL) | 25 | 2015 |
| Nigeria | Uge | 80 | 2019 | UAE | Shah Sour Gas (condensate) | 25 | 2015 |

# Table 4

## WORLD REFINERY CAPACITY ADDITIONS

(thousand barrels per day)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|
| **Refinery Capacity Additions and Expansions[1]** | | | | | | | | |
| OECD Americas | -45 | 329 | 455 | 50 | | 40 | | 874 |
| OECD Europe | -245 | | | | 214 | | | 214 |
| OECD Asia Oceania | -327 | -226 | -155 | -76 | | | | -457 |
| FSU | 115 | 70 | | 120 | | | | 190 |
| Non-OECD Europe | -6 | | | | | | | |
| China | 630 | 30 | 490 | 600 | 400 | | | 1,520 |
| Other Asia | 270 | 125 | 330 | 200 | 206 | 300 | | 1,161 |
| Latin America | 115 | 200 | 70 | 165 | | 33 | 50 | 518 |
| Middle East | 420 | 417 | 296 | 230 | 570 | 80 | 88 | 1,681 |
| Africa | 15 | | 25 | | 90 | 120 | 500 | 735 |
| **Total World** | 942 | 945 | 1,511 | 1,289 | 1,480 | 573 | 638 | 6,436 |
| **Upgrading Capacity Additic** | .58 | | | | | | | |
| OECD Americas | 92 | 143 | 107 | | 55 | | | 305 |
| OECD Europe | 36 | | 70 | | 106 | | | 176 |
| OECD Asia Oceania | -63 | -36 | | | | | | -36 |
| FSU | 87 | 133 | 271 | 98 | 178 | 201 | 95 | 976 |
| Non-OECD Europe | 75 | 116 | 40 | | | | | 156 |
| China | 325 | 48 | 195 | 360 | 162 | 34 | | 799 |
| Other Asia | 346 | 309 | 133 | 80 | 156 | | | 678 |
| Latin America | | 258 | | 163 | | 29 | 104 | 554 |
| Middle East | 332 | 217 | 81 | 66 | 80 | 141 | 127 | 712 |
| Africa | | | | 57 | | 50 | | 107 |
| **Total World** | 1,230 | 1,188 | 897 | 824 | 737 | 455 | 326 | 4,427 |
| **Desulphurisation Capacity Additions[3]** | | | | | | | | |
| OECD Americas | 85 | 60 | | 35 | | | | 95 |
| OECD Europe | -106 | | | | 114 | | | 114 |
| OECD Asia Oceania | -213 | | | | | | | |
| FSU | 49 | 199 | 73 | 65 | 80 | | | 417 |
| Non-OECD Europe | 45 | 20 | | | | | | 20 |
| China | 577 | 49 | 147 | 408 | 296 | 60 | | 960 |
| Other Asia | 91 | 111 | 180 | 209 | 98 | | | 598 |
| Latin America | | 230 | | 40 | | 64 | 30 | 364 |
| Middle East | 531 | 220 | 200 | 82 | 207 | 325 | 194 | 1,228 |
| Africa | 37 | | | 42 | | | | 42 |
| **Total World** | 1,097 | 890 | 600 | 881 | 795 | 449 | 224 | 3,838 |

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.

2 Comprises gross capacity additions to coking, hydrocracking, residue hydrocracking, visbreaking, FCC or RFCC capacity.

3 Comprises additions to hydrotreating and hydrodesulphurisation capacity.

4 New OECD members Chile and Israel are stil l accounted for in Latin America and M iddle East, respectively. Estonia and Slovenia have no refineries

# Table 4a
## WORLD REFINERY CAPACITY ADDITIONS:
## Changes from Last Medium-Term Report
(thousand barrels per day)

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | Total |
|---|---|---|---|---|---|---|---|---|
| **Refinery Capacity Additions and Expansions**[1] | | | | | | | | |
| OECD Americas | | -40 | 40 | 60 | | | | 60 |
| OECD Europe | | -135 | | | | | | -135 |
| OECD Asia Oceania | 14 | | -124 | -155 | -76 | | | -355 |
| FSU | 10 | 40 | -140 | -137 | 120 | | | -117 |
| Non-OECD Europe | | -6 | | | | | | -6 |
| China | | | -340 | -100 | -100 | 300 | | -240 |
| Other Asia | | -300 | 180 | 270 | | -54 | | 96 |
| Latin America | | | -25 | -33 | | -50 | 33 | -75 |
| Middle East | | -70 | -30 | 90 | 45 | | -180 | -145 |
| Africa | -86 | | -5 | -10 | -220 | 90 | 120 | -25 |
| **Total World** | -62 | -511 | -444 | -15 | -231 | 286 | -27 | -942 |
| **Upgrading Capacity Additions**[2] | | | | | | | | |
| OECD Americas | | -58 | 20 | 82 | | | | 44 |
| OECD Europe | | -36 | | 50 | | | | 14 |
| OECD Asia Oceania | 25 | | | | | | | |
| FSU | -95 | -18 | -92 | -12 | 58 | 27 | 121 | 84 |
| Non-OECD Europe | -7 | 7 | | | | | | 7 |
| China | | | -161 | -55 | 63 | 162 | 34 | 43 |
| Other Asia | | -286 | 193 | 93 | | | | |
| Latin America | | | | | | -104 | 29 | -75 |
| Middle East | | | -90 | 15 | 66 | | 113 | 104 |
| Africa | | | | | -50 | | 50 | |
| **Total World** | -77 | -391 | -130 | 173 | 138 | 85 | 346 | 220 |
| **Desulphurisation Capacity Additions**[3] | | | | | | | | |
| OECD Americas | | | | | 35 | | | 35 |
| OECD Europe | | -103 | | | | | | -103 |
| OECD Asia Oceania | | | | | | | | |
| FSU | | -26 | -47 | 48 | 25 | 80 | | 80 |
| Non-OECD Europe | | | | | | | | |
| China | | 60 | -44 | -107 | -134 | 296 | 60 | 132 |
| Other Asia | | -255 | 131 | 154 | | | | 30 |
| Latin America | | -41 | | | | -30 | 64 | -7 |
| Middle East | -50 | 5 | -55 | 101 | 61 | 39 | 223 | 374 |
| Africa | -36 | | | | | | | |
| **Total World** | -86 | -360 | -16 | 197 | -13 | 385 | 347 | 541 |

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.
2 Comprises stand-alone additions to coking, hydrocracking or FCC capacity. Excludes upgrading additions counted under 'Refinery Capacity Additions and Expansions' category.
3 Comprises stand-alone additions to hydrotreating and hydrodesulphurisation capacity. Excludes desulphurisation additions counted under 'Refinery Capacity Additions and Expansions' category.

## Table 4b
## SELECTED REFINERY CRUDE DISTILATION PROJECT LIST

| Country | Project | Capacity (kbd)[1] | Start Year |
|---|---|---|---|
| ***OECD Americas*** | | | |
| Canada | North West Redwater Partnership - Edmonton | 50 | 2017 |
| Mexico | Petroleos Mexicanos - Tula Hidalgo | 40 | 2019 |
| United States | Virtual Engineering - Allen Parish | 20 | 2015 |
| United States | MDU Resources (W/Calumet) - Dakota Prairie Refining | 20 | 2015 |
| United States | National Cooperative Refining Assoc. - McPherson | 15 | 2015 |
| United States | Marathon Petroleum Co. LLC - Catlettsburg | 35 | 2015 |
| United States | Marathon Petroleum Co. LLC - Canton | 25 | 2015 |
| United States | Kinder Morgan - Galena Park | 50 | 2015 |
| United States | Valero Energy Corp. - Sunray | 25 | 2015 |
| United States | Western Refining Inc. - El Paso | 25 | 2015 |
| United States | Holly Corp. - Woods Cross | 14 | 2015 |
| United States | Castleton Commodities - Corpus Christi | 100 | 2015 |
| United States | The Three Affiliated Tribes - Thunder Butte Petroleum Services | 15 | 2016 |
| United States | Alon Refining - Bakersfield | 65 | 2016 |
| United States | Calumet Montana Refining - Great Falls | 20 | 2016 |
| United States | Marathon Petroleum Co. LLC - Robinson | 30 | 2016 |
| United States | Valero Energy Corp. - Corpus Christi | 70 | 2016 |
| United States | Valero Energy Corp. - Houston | 90 | 2016 |
| United States | Martin Midstream Partners - Corpus Christi | 100 | 2016 |
| United States | Magellan - Corpus Christi | 50 | 2016 |
| ***OECD Europe*** | | | |
| Turkey | Socar - Aliaga/Izmir | 214 | 2018 |
| ***OECD Asia Oceania*** | | | |
| Australia | BP PLC - Bulwer Island | -102 | 2015 |
| Japan | Cosmo Oil Co. Ltd. - Chiba | -48 | 2015 |
| Japan | Tonen General + Kyokuto - Unknown | -76 | 2015 |
| Japan | JX Energy - Unknown | -121 | 2016 |
| Japan | Showa Shell - Unknown | -34 | 2016 |
| Japan | Fuji Oil Co. Ltd. - Unknown | -13 | 2017 |
| Japan | Idemitsu Kosan Co. Ltd. - Ichihara, Chiba | -50 | 2017 |
| Japan | Taiyo Oil Co. Ltd. - Uknown | -13 | 2017 |
| ***FSU*** | | | |
| Kazakhstan | Kazmunigaz/CNPC - Chimkent | 120 | 2017 |
| Russia | Novatek - Ust-Luga | 70 | 2015 |
| ***China*** | | | |
| China | Sinopec - Jiujiang | 30 | 2015 |
| China | CNPC - Daqing Heilongjiang | 90 | 2016 |
| China | CNOOC - Huizhou | 200 | 2016 |
| China | CNOOC - Taizhou | 60 | 2016 |
| China | CNOOC/Local Ningbo Daxie - Zhejiang | 140 | 2016 |
| China | CNPC - Huabei | 100 | 2017 |
| China | Sinopec/KPC/Others - Zhanjiang | 300 | 2017 |
| China | CNPC/Saudi Aramco - Kunming/Anning | 200 | 2017 |
| China | CNPC/PDVSA - Jieyang | 400 | 2018 |

| Country | Project | Capacity (kbd)[1] | Start Year |
|---|---|---|---|
| ***Other Asia*** | | | |
| China, Taiwan | Chinese Petroleum Corp. - Kaohsiung | -205 | 2015 |
| China, Taiwan | Chinese Petroleum Corp. - Ta-LIn | 150 | 2016 |
| India | Indian Oil Co. Ltd. - Paradip | 300 | 2015 |
| India | Indian Oil Co. Ltd. - Panipat | 60 | 2016 |
| India | Nagarjuna oil Co - Cuddalore | 120 | 2016 |
| India | BPCL - Kochi | 120 | 2018 |
| India | Indian Oil Co. Ltd. - Koyali, Gujarat | 86 | 2018 |
| Malaysia | Petronas - Rapid | 300 | 2019 |
| Pakistan | Attock Refinery Ltd. - Rawalpindi | 10 | 2015 |
| Thailand | PTT PLC - Bangchak Bangkok | 20 | 2015 |
| Viet Nam | Petro vietnam/KPC/Idemitsu Kosan - Nghi Son | 200 | 2017 |
| ***Middle East*** | | | |
| Bahrain | Bahrain Petroleum Co. - Sitra | 350 | 2020 |
| Bahrain | Bahrain Petroleum Co. - Sitra | -262 | 2020 |
| Bahrain | Bahrain Petroleum Co. - Sitra | 88 | 2020 |
| Iran | National Iranian Oil Co. - Persian Gulf Star Refinery | 120 | 2016 |
| Iran | National Iranian Oil Co. - Persian Gulf Star Refinery | 120 | 2017 |
| Iran | National Iranian Oil Co. - Persian Gulf Star Refinery | 120 | 2018 |
| Iran | National Iranian Oil Co. - Abadan | 195 | 2020 |
| Iran | National Iranian Oil Co. - Abadan | -195 | 2020 |
| Iraq | Qaiwan - Baizan | 50 | 2018 |
| Kuwait | Kuwait National Petroleum Co. - Mina Abdulla/Mina al-Ahmadi | 65 | 2019 |
| Oman | Oman Refinery Co. - Sohar | 60 | 2017 |
| Oman | Sohar Bitumen Refinery - Sohar | 30 | 2016 |
| Qatar | QatarPetroleum - Ras Laffan 2 | 146 | 2016 |
| Saudi Arabia | Saudi Aramco - Sumitomo - Rabigh 2 | 50 | 2017 |
| Saudi Arabia | Saudi Aramco - Jizan | 400 | 2018 |
| UAE-Abu Dhabi | Abu Dhabi National Oil Co. - Ruwais 2 | 417 | 2015 |
| Yemen | Yemen - Hunt - Marib | 15 | 2019 |
| ***Non-OECD Americas*** | | | |
| Brazil | Petrobras - Pernambuco State Abreu e Lima | 115 | 2015 |
| Brazil | Petrobras - COMPERJ | 165 | 2017 |
| Colombia | Empresa Colombiana de Petroleos - Cartagena, Bolivar | 85 | 2015 |
| Colombia | Empresa Colombiana de Petroleos - Barrancabermeja-Santander | 50 | 2020 |
| Peru | Petroperu SA - Talara, Piura | 33 | 2019 |
| Venezuela | Petroleos de Venezuela SA - Puerto de la Cruz | 30 | 2016 |
| Venezuela | Petroleos de Venezuela SA - Santa Inés (Barinas) | 40 | 2016 |
| ***Africa*** | | | |
| Algeria | Naftec SPA - Arzew | 25 | 2016 |
| Angola | Sonangol - Lobito | 120 | 2019 |
| Egypt | MIDOR - Alexandria | 60 | 2018 |
| Nigeria | Dangote Oil Refining Company - Lekki Free Trade Zone (Lagos) | 500 | 2020 |
| Uganda | Total/Tullow/CNOOC - Albertine Graben | 30 | 2018 |

# Table 5
## WORLD ETHANOL PRODUCTION[1]
(thousand barrels per day)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| **OECD** | | | | | | | |
| OECD Americas[2] | 960 | 970 | 966 | 964 | 961 | 960 | 960 |
| United States | 929 | 937 | 932 | 932 | 933 | 933 | 934 |
| Canada | 31 | 32 | 32 | 30 | 27 | 26 | 25 |
| OECD Europe[3] | 83 | 94 | 99 | 102 | 105 | 106 | 111 |
| Austria | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Belgium | 8 | 7 | 7 | 7 | 7 | 7 | 7 |
| France | 16 | 17 | 17 | 18 | 18 | 18 | 19 |
| Germany | 16 | 16 | 17 | 17 | 17 | 17 | 18 |
| Italy | 2 | 3 | 3 | 4 | 4 | 4 | 5 |
| Netherlands | 5 | 6 | 8 | 8 | 8 | 8 | 9 |
| Poland | 5 | 6 | 6 | 6 | 6 | 6 | 6 |
| Spain | 6 | 7 | 8 | 8 | 8 | 8 | 8 |
| UK | 10 | 12 | 13 | 15 | 16 | 16 | 17 |
| OECD Asia Oceania[4] | 4 | 4 | 4 | 4 | 3 | 3 | 3 |
| Australia | 3 | 3 | 2 | 2 | 2 | 2 | 2 |
| **Total OECD** | **1,048** | **1,068** | **1,068** | **1,070** | **1,069** | **1,069** | **1,074** |
| **Non-OECD** | | | | | | | |
| FSU | 2 | 3 | 3 | 3 | 4 | 4 | 4 |
| Non-OECD Europe | 1 | 1 | 1 | 1 | 1 | 1 | 2 |
| China | 39 | 43 | 45 | 47 | 49 | 51 | 52 |
| Other Asia | 41 | 49 | 54 | 56 | 62 | 63 | 67 |
| India | 13 | 16 | 17 | 17 | 18 | 19 | 20 |
| Indonesia | 2 | 3 | 3 | 3 | 4 | 4 | 4 |
| Malaysia | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Philippines | 3 | 4 | 5 | 5 | 6 | 6 | 7 |
| Singapore | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Thailand | 19 | 22 | 23 | 24 | 25 | 25 | 26 |
| Latin America | 526 | 534 | 537 | 550 | 559 | 567 | 575 |
| Argentina | 10 | 13 | 13 | 14 | 15 | 15 | 16 |
| Brazil | 494 | 496 | 498 | 509 | 515 | 522 | 528 |
| Colombia | 8 | 9 | 9 | 10 | 11 | 12 | 12 |
| Middle East | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Africa | 5 | 9 | 10 | 12 | 14 | 14 | 16 |
| **Total Non-OECD** | **617** | **640** | **652** | **671** | **689** | **701** | **716** |
| **Total World** | **1,665** | **1,709** | **1,721** | **1,741** | **1,758** | **1,771** | **1,790** |

1 Volumetric production; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of conventional gasoline.
2 As of August 2012 OMR, OECD Americas includes Chile.
3 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.
4 As of August 2012 OMR, OECD Asia Oceania includes Israel.

# Table 5a
## WORLD BIODIESEL PRODUCTION[1]
(thousand barrels per day)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| **OECD** | | | | | | | |
| OECD Americas[2] | 87 | 89 | 88 | 88 | 87 | 87 | 86 |
| United States | 82 | 84 | 84 | 84 | 84 | 84 | 84 |
| Canada | 5 | 5 | 4 | 4 | 3 | 3 | 2 |
| OECD Europe[3] | 196 | 201 | 206 | 209 | 216 | 218 | 226 |
| Austria | 5 | 5 | 5 | 5 | 6 | 6 | 6 |
| Belgium | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| France | 37 | 37 | 37 | 38 | 38 | 38 | 39 |
| Germany | 52 | 52 | 52 | 52 | 52 | 52 | 53 |
| Italy | 8 | 9 | 10 | 10 | 11 | 11 | 13 |
| Netherlands | 25 | 25 | 28 | 28 | 29 | 29 | 29 |
| Poland | 5 | 6 | 6 | 6 | 6 | 6 | 6 |
| Spain | 15 | 15 | 15 | 17 | 17 | 18 | 20 |
| UK | 4 | 5 | 6 | 6 | 6 | 6 | 6 |
| OECD Asia Oceania[4] | 9 | 10 | 10 | 10 | 10 | 10 | 10 |
| Australia | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total OECD** | **293** | **300** | **305** | **308** | **313** | **315** | **322** |
| **Non-OECD** | | | | | | | |
| FSU | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Non-OECD Europe | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| China | 5 | 6 | 6 | 7 | 7 | 8 | 9 |
| Other Asia | 99 | 96 | 99 | 106 | 111 | 115 | 118 |
| India | 1 | 1 | 2 | 3 | 3 | 3 | 3 |
| Indonesia | 50 | 42 | 43 | 45 | 48 | 49 | 50 |
| Malaysia | 9 | 11 | 12 | 13 | 13 | 14 | 15 |
| Philippines | 3 | 4 | 5 | 6 | 7 | 7 | 7 |
| Singapore | 15 | 16 | 17 | 17 | 18 | 18 | 19 |
| Thailand | 21 | 21 | 21 | 23 | 23 | 24 | 25 |
| Latin America | 110 | 127 | 133 | 137 | 142 | 144 | 148 |
| Argentina | 43 | 42 | 44 | 46 | 48 | 49 | 50 |
| Brazil | 53 | 70 | 74 | 75 | 77 | 79 | 80 |
| Colombia | 8 | 10 | 10 | 10 | 11 | 11 | 12 |
| Middle East | 0 | 0 | 0 | 1 | 1 | 1 | 1 |
| Africa | 4 | 5 | 6 | 8 | 8 | 8 | 10 |
| **Total Non-OECD** | **221** | **239** | **249** | **263** | **273** | **281** | **289** |
| **Total World** | **513** | **539** | **553** | **571** | **586** | **596** | **611** |

1 Volumetric production; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of conventional gasoline.
2 As of August 2012 OMR, OECD Americas includes Chile.
3 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.
4 As of August 2012 OMR, OECD Asia Oceania includes Israel.

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# OIL
# Medium-Term Market Report 2015

The recent oil market sell off, brought on by deep imbalances after years of record-high prices, will likely prove a milestone in the history of oil. However prices eventually evolve, markets may never be the same. This edition of the *Medium-Term Oil Market Report* sizes up the magnitude of this transformation so far and sketches the oil landscape at the 2020 horizon.

It is not just oil price signals that have changed, but also the market's responsiveness to them. On the supply side, this *Report's* forecast reflects not just lower price assumptions, but also the high price-sensitivity of US light tight oil compared with conventional crude, as well as OPEC's embrace of market forces in late 2014 in a bid for market share. On the demand front, it shows how the response to lower prices will differ in a low-growth, deflationary environment compared to a higher-growth one.

Not all factors can be easily predicted. Much hangs on the outcome of talks between Iran and the "P5+1", on Islamist violence in oil-producing countries, and on future relations between Russia and the West. Such geopolitical risk factors are themselves a defining feature of the oil market for the medium term.

As in previous editions, this *Report* also offers key projections of global refining capacity, crude trade flows and product supply, this year with special focus on the impact of changing bunker fuel legislation.

Rarely has the oil market faced changes as sweeping as today. That makes the insights from the IEA *Medium-Term Oil Market Report 2015* all the more timely and valuable.

## Market Analysis and Forecasts to 2020

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