OIL Medium-Term Market Report 2013

Market Trends and Projections to 2018

International Energy Agency

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The global oil market will undergo sweeping changes over the next five years. The 2013 *Medium-Term Oil Market Report* evaluates the impact of these changes on the global oil system by 2018 based on all that we know today – current expectations of economic growth, existing or announced policies and regulations, commercially proven technologies, field decline rates, investment programmes (upstream, midstream and downstream), etc. The five-year forecast period corresponds to the length of the typical investment cycle and as such is critical to policymakers and market participants.

This *Report* shows, in detailed but concise terms, why the ongoing North American hydrocarbon revolution is a "game changer". The region's expected contribution to supply growth, however impressive, is only part of the story: Crude quality, infrastructure requirements, current regulations, and the potential for replication elsewhere are bound to spark a chain reaction that will leave few links in the global oil supply chain unaffected.

While North America is expected to lead medium-term supply growth, the East-of-Suez region is in the lead on the demand side. Non-OECD oil demand, led by Asia and the Middle East, looks set to overtake the OECD for the first time as early as 2Q13 and will widen its lead afterwards. Non-OECD economies are already home to over half global refining capacity. With that share only expected to grow by 2018, the non-OECD region will be firmly entrenched as the world's largest crude importer.

These and other changes are carefully laid out in this *Report*, which also examines recent and future changes in global oil storage, shifts in OPEC production capacity and crude and product trade, and the consequences of the ongoing refinery construction boom in emerging markets and developing economies.

It is required reading for anyone engaged in policy or investment decision-making in the energy sphere, and those more broadly interested in the oil market and the global economy.

Market Trends and Projections to 2018

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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FOREWORD

When describing the energy world of tomorrow, it is often said that while the fuel mix is getting greener and more diversified, oil is set to "remain" a main source of energy for the foreseeable future. While accurate, that expression is also misleading. For it conveys a false idea of a static, residual commodity, in sharp contrast with the highly dynamic, changing nature of the oil market, and of the oil commodity itself.

In the last few years, rising supplies of US light, tight oil (LTO) have turned upside down, or at least called into question, the conventional wisdom about what oil is, how it is extracted, how much of it is left in the ground, and how it can be processed and used. A mature economy which some 150 years ago had been the cradle of the oil industry, but had since faced what seemed like an irreversible production decline, all of a sudden found itself at the centre of a new oil boom. The rock formations being tapped with such success in the United States don't look anything like the oilfields of the Rockefeller era, though, and for decades had seemed beyond economic exploitation. Much remains to be learned about the extent of this resource not just in the United States but around the world. But the unlocking of US LTO has opened up a world of possibilities. Expectations of future supply have begun to shift. Subject to trends in prices and technology, there is a possibility that tight oil plays might be tapped elsewhere. The broader application of some of the techniques used to tap LTO already appears to boost production in various conventional plays in mature areas of Russia and China, among others.

Big as it may be, the US LTO boom is just one part of the oil story. While supply growth has North America in the lead, incremental production capacity continues to flow from the Middle East, notably Iraq and Saudi Arabia. On the demand front, East-of-Suez markets are in the driver's seat. Non-OECD consumption looks set to overtake the OECD in 2Q13 and to keep widening its lead from that point on. The non-OECD, already host to most of the world's refineries, is also where most increases in crude distillation and upgrading capacity are expected in the next five years. By that time, most of the world's internationally traded crude will sail to non-OECD refiners.

This *Medium-Term Oil Market Report* aims to draw the implications of these and other developments for the next five years, a period that broadly corresponds to the average investment cycle and is thus of critical importance to investors and policymakers. It is part of a series of outlook reports devoted to each of the four main fuels – oil, natural gas, coal, renewable energy – and, starting this year, energy efficiency. Also starting this year, these reports are being released in close succession, sharing GDP and other assumptions to make them as comparable as possible.

The period covered by this outlook marks a watershed in oil market history, a time when non-OECD economies are rapidly expanding their oil footprint. This year is also a milestone for the IEA, a period of increasingly close cooperation with key non-OECD countries towards greater energy security, more informed energy policies and a better understanding of energy markets.

This *Report* is being published under my authority as Executive Director of the IEA.

Maria van der Hoeven

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OVERVIEW

Following several years of stronger-than-expected North American supply growth, the shockwaves of rising United States (US) shale gas and light tight oil (LTO) and Canadian oil sands production are reaching virtually all recesses of the global oil market. This North American supply revolution is not happening in a vacuum. Sustained high oil prices helped unleash it. Its impact is also compounded by other market developments, most prominently social and political turmoil in the MENA region in the wake of the 'Arab Spring' and the shift in demand to East-of-Suez markets. Together, these powerful forces are redefining the way oil is being produced, processed, traded and consumed around the world. There is hardly any aspect of the global oil supply chain that will not undergo some measure of transformation over the next five years, with significant consequences for the global economy and oil security.

Global Balance Summary

(million barrels per day)

	2012	2013	2014	2015	2016	2017	2018
GDP Growth Assumption (% per year)	**3.09**	**3.39**	**4.03**	**4.30**	**4.41**	**4.47**	**4.44**
Global Demand	**89.78**	**90.58**	**91.80**	**93.12**	**94.38**	**95.58**	**96.68**
Non-OPEC Supply	53.35	54.43	55.79	57.03	57.84	58.62	59.31
OPEC NGLs, etc.	6.31	6.56	6.75	6.90	7.00	6.97	7.00
Global Supply excluding OPEC Crude	**59.66**	**60.98**	**62.54**	**63.92**	**64.84**	**65.59**	**66.30**
OPEC Crude Capacity	**35.00**	**35.35**	**36.30**	**36.37**	**36.66**	**36.80**	**36.75**
Call on OPEC Crude + Stock Ch.	**30.12**	**29.59**	**29.26**	**29.19**	**29.54**	**29.99**	**30.37**
Implied OPEC Spare Capacity[1]	4.87	5.76	7.04	7.18	7.12	6.81	6.38
as percentage of global demand	*5.4%*	*6.4%*	*7.7%*	*7.7%*	*7.5%*	*7.1%*	*6.6%*
Changes since October 2012 MTOGM							
Global Demand	**-0.01**	**-0.02**	**-0.03**	**-0.05**	**-0.07**	**-0.09**	
Non-OPEC Supply	0.14	0.46	0.99	1.07	1.00	1.09	
OPEC NGLs, etc.	0.09	0.06	0.11	0.02	0.04	0.03	
Global Supply excluding OPEC Crude	**0.22**	**0.52**	**1.10**	**1.08**	**1.04**	**1.13**	
OPEC Crude Capacity	**0.00**	**-0.42**	**-0.60**	**-1.05**	**-0.89**	**-0.75**	
Call on OPEC Crude + Stock Ch.	**-0.23**	**-0.55**	**-1.12**	**-1.13**	**-1.12**	**-1.22**	
Implied OPEC Spare Capacity[1]	0.23	0.12	0.52	0.09	0.23	0.47	

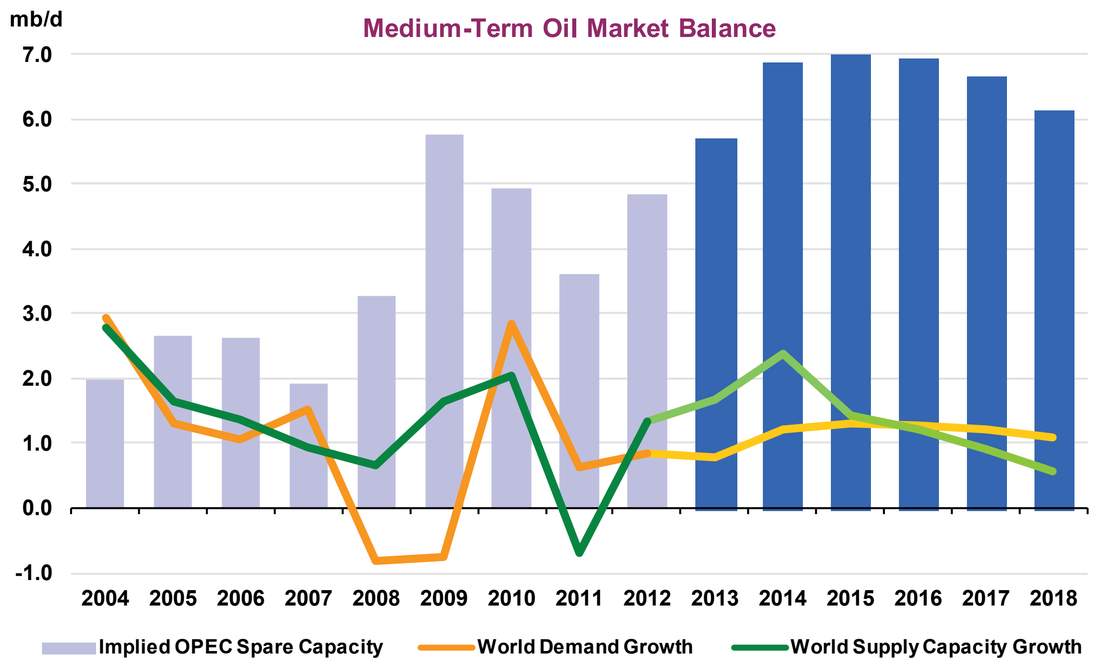
1 OPEC Capacity minus 'Call on Opec + Stock Ch.'

Note: unless otherwise indicated, all material in figures and tables derives from IEA data and analysis.

Supply growth and the resurgent North American primacy

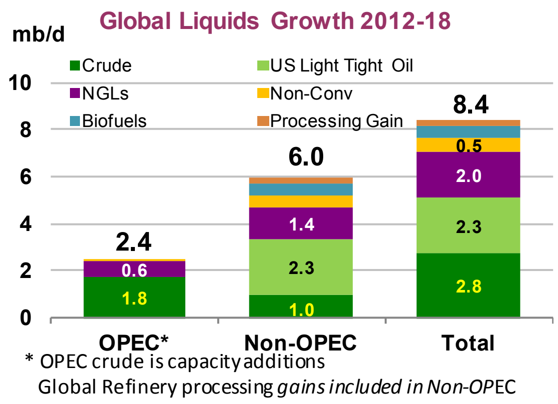
Regional contrasts that were identified in the previous edition of the *Medium-Term Oil Market Report* (*MTOMR)*, released in October 2012, have become even more pronounced in the last few months. On the upstream front, incremental North American LTO and oil sands production, which already towered over the 2012 *MTOMR*, has increased in prominence. The forecast of non-OPEC supply growth has been adjusted upwards, with North America now forecast to grow by 3.9 mb/d from 2012 to 2018, accounting for more than half of the increase. Downward revisions to the non-OPEC forecast are limited to a 60 kb/d cut to the forecast for Africa.

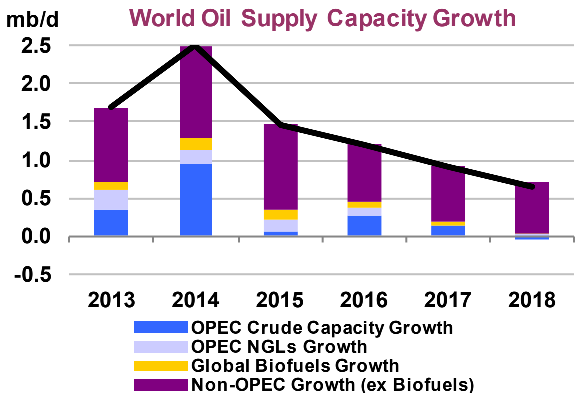
Although non-OPEC supply growth looks more robust than in the 2102 *MTOMR*, those upwards revisions are offset by downward adjustments in OPEC crude production capacity. Several members of the producer group face new hurdles, notably in North and sub-Saharan Africa. The regional fallout from the 'Arab Spring' is taking a toll on investment and capacity growth. Security risks are on the rise, compounding the uncertainty about future changes to the oil laws and investment regime. Two years into the region's process of far-reaching social and political transition, the biggest challenges lie ahead. A resurgent Iraq remains the largest single source of incremental OPEC capacity, but a host of above-ground problems – administrative hurdles, delays to contract awards, disagreements over payments between Erbil and Baghdad, lingering security risks and problems in executing investment and production plans – are bogging down development. Downward adjustments across the group are partly offset by substantially stronger growth in Saudi capacity than previously expected, reflecting newly announced development projects. But the balance of global supply growth, more or less evenly split between OPEC and non-OPEC in the 2012 *MTOMR*, is tilting towards the latter. North America thus increases its share of supply growth both within the non-OPEC group and more globally.



Non-OECD economies take the lead in most other aspects of the market

In every other aspect of the supply chain, be it demand, refining, trade or storage and transportation, the fast rise of the non-OECD region is striking. Emerging market and developing economies are projected to overtake advanced economies in oil product consumption as of 2Q13 and to widen their lead through the forecast period, jumping from 49% of global demand in 2012 to more than 54% by 2018. Taken in aggregate, OECD refining, notwithstanding a renaissance in the US, is increasingly relinquishing market share to the non-OECD region, a form of de facto off-shoring not unlike the trend in other manufacturing sectors. Already most of the world's refining capacity is located in non-OECD economies. In the next five years, virtually all net crude distillation capacity growth is forecast to take place in the emerging market and developing economies. Non-OECD refineries are also rapidly catching up with the OECD in conversion depth and complexity. And while international crude trade appears poised to contract in the next five years as refineries move closer to the wellhead, more of that internationally traded crude is expected to end up in non-OECD economies, whose share of global crude imports looks set to push through 50% by the end of the forecast period.





Last but not least, these tectonic shifts in supply, demand and refining capacity growth have sparked an explosion of storage capacity. This is relatively well documented in North America, where news of logistics and storage additions can move markets and have been closely watched. But rising Asian import needs and changing crude and product trade patterns have sparked equally strong, though less broadly publicised, storage and transport infrastructure growth in the non-OECD region, whether for commercial or strategic purposes. As trade patterns shift, new trading hubs are emerging at both OECD and non-OECD strategic locations such as Northwest Europe and the Caribbean. Storage terminals are being expanded along the African coast amid rising African imports of LPG and transportation fuels. Non-OECD companies are expanding their international footprint in some of those strategically located terminals, while trading firms seek to expand and leverage their storage assets to arbitrage emerging supply/demand imbalances.

Beyond supply growth: the LTO paradigm shift

The intrinsic complexity of the oil market is such that its transformation cannot be pinned down to any single cause. There is a long list of factors that will shape market developments in the next five years, ranging from the impact of sustained high oil prices to shifts in the global economy (including Europe's debt crisis and China's changing pace of growth) to the social and political transition in the MENA (including, but not limited to, the outcome of the Syrian conflict and how the international dispute over Iran's nuclear plans is resolved). Yet a common thread runs through many of the developments forecast in the oil market for the next five years. While continued uncertainties remain about the economics and ultimate impact of unconventional production technologies, recent developments in North American supply stand out as an overarching driver, colouring the way in which virtually all other factors impact the market, and causing ripple effects through all aspects of the oil industry, from supply to demand and all the links in between.

What makes the tight oil boom truly transformative is not just the sheer production volumes unlocked but the combination of volumetric production growth with other factors: the crude's distinctively light quality, the unconventional nature of both the plays from which it is extracted and the technologies which have unlocked it, the economic and market impact of the new production, and the chain reaction it is creating in the global transportation, storage and refining infrastructure.

Incremental North American supply clearly played a critical role in offsetting record supply disruptions in 2012, and is likewise forecast to help offset decline rates elsewhere through the forecast period. Yet one needs not go far back in history to find times when Saudi production went through comparable swings, whether on the upside or the downside, without causing a paradigm shift. The case of US LTO is distinctive in that rising production is causing an unexpected quality shift in the global crude mix. While many supply growth forecasts had long been predicated on the notion of a shift in crude quality towards heavier and sourer grades, LTO is exceptionally light and sweet, including large volumes of field condensate. While a good fit for some US refineries which had seemed on the brink of closure, the supply boom is proving a challenge as well as an opportunity for others, which had bet on a widening heavy-light price spread and invested massively in upgrading capacity. The adjustments required in the US refining and petrochemical industry to absorb and leverage continued light-end supply growth will send ripple effects far beyond the US, through the global refining industry and product markets, and may result in part in large US exports of such light products as gasoline, naphtha and other petrochemical feedstock.

Another distinctive trait of the North American supply boom is that it is taking place at the heart of one of the world's most highly industrialised, mature economies. The emergence of large-scale new supply in such a context will necessarily play out very differently from the way in which a comparable increase might affect the market if it came from a Middle East or sub-Saharan producer. The initial impact of the LTO boom on global crude markets has thus been indirect: rather than seeking out export markets, the new supply has so far affected international crude markets mostly by backing out imports. Future growth could be constrained by logistical and marketing challenges, however. Those stem both from the inland and relatively remote locations of many of the new plays and from current US law restricting most crude exports, as well as from proposed European legislation that could effectively ban some or all European oil imports from North America. This *Report* assumes that US restrictions will largely remain in place through the forecast period, though other scenarios are clearly possible. On the logistics front, new infrastructure designed to transport LTO to coastal markets may cause significant changes in crude and benchmark pricing. New terminals and trading hubs may appear on the Gulf Coast or wherever else LTO or Canadian heavy oil and syncrude might be traded. Price reporting agencies and oil companies are reportedly mulling new LTO-related benchmarks in Texas or Louisiana.

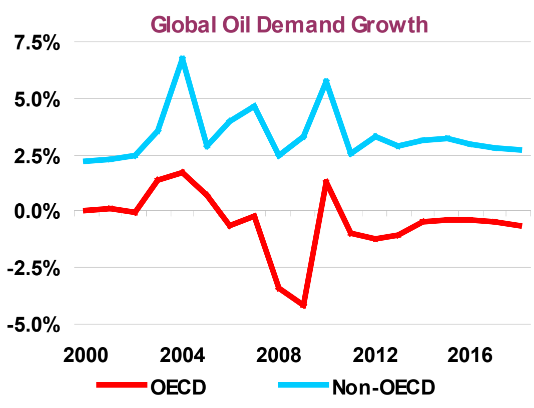
The revolutionary power of the North American supply boom also reflects the still untested potential for replicating and applying transformative new technologies developed in US LTO plays to other oil provinces with comparable success. This includes not only tapping shale oil and gas resources in places ranging from Latin America to China and Russia, but also extending the life and yield of low-permeability conventional crude plays. Companies in countries ranging from China to Russia to Saudi Arabia are already reporting good results in applying fracturing technology to enhance recovery in mature conventional plays. Although uncertainties remain, it is impossible to ignore the possibility that current non-conventional technologies, as they spread and get both perfected and mainstreamed, could lead to a wholesale reassessment of global reserves. Although challenges abound and the full impact of this transformation may not occur until after our forecast period, expectations of future resource availability and production potential are already undergoing a sea change.

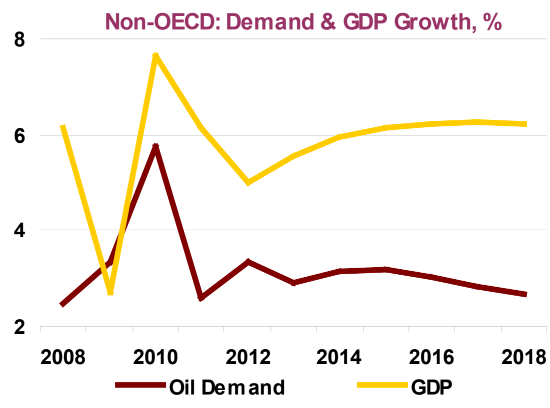
Last but not least, the surge in US shale gas production and associated shifts in natural gas pricing are challenging the conventional wisdom about fuel switching and gas-in-transport. Cheap and abundant natural gas has already facilitated the transition of the US economy towards broader use of the fuel.

But US fuel switching so far has mostly come at the expense of coal, whose share of US power generation has collapsed. The conversion of US space heating from oil to gas was well underway before the shale gas revolution, and the scope for further substitution is comparatively limited. Oil-to-gas substitution in transport would have a larger impact as the sector accounts for the lion's share of oil demand. Long seen as a remote possibility, transport gas now looks much closer to becoming a reality. This is true not only of the US market but also of China and other gas producers such as Australia. Given the considerable infrastructure build-up required to convert the vehicle fleet and fuel distribution network to gas, transport gas will not likely happen in a big way until after the forecast period, and the next five years are more likely to witness the rollout of the needed infrastructure than a large-scale shift in the fuel mix. Nevertheless, as with supply factors associated with LTO developments, expectations are shifting, and this forecast expects natural gas to start making meaningful inroads into the transport sector towards the end of the forecast period.

Demand: beyond the BRICS

The primary driver of oil consumption growth is the economy, but global demand in the next five years will also be affected by the broader economic impacts of the North American supply revolution. The economic assumptions used in this *Report* are those of the International Monetary Fund's *World Economic Outlook* of April 2013, which notes a "growing bifurcation [within advanced economies] between the United Sates on one hand and the euro area on the other." The two-speed pattern of economic recovery that had prevailed until now has thus evolved into a three-speed recovery characterised by a growing divergence in economic growth between three main blocks: non-OECD economies, low-growth European advanced economies and the US.





In demand terms, the non-OECD region is projected to increase its lead over the rest of the world from 2Q13, when oil demand in emerging and developing economies is estimated to have exceeded that in advanced economies for the first time, through the end of the forecast period. But this broad trend, which extends earlier patterns of demand growth, should not obscure new shifts in the allocation of demand growth within the non-OECD region itself. Chinese demand growth, by far the most powerful engine of growth in the last 10 to 15 years, is expected to shift to a lower gear as the country's government, under new leadership, changes the focus of economic policy from an aggressive emphasis on growth to a stance that balances expansionary objectives with an attention to the quality of growth and the need to address global economic and monetary imbalances. China is also expected to embark on a drive to address severe urban pollution problems through greater efficiency and emission control in coal-fired power generation, but also by encouraging the use of natural gas in transport.

Whereas non-OECD demand growth had been led in the last few years by the so-called BRICS countries (Brazil, Russia, India, China and South Africa) and Saudi Arabia, a shift toward slower Chinese growth may help decrease their share of incremental demand somewhat. At the same time, demand growth is expected to pick up momentum in other non-OECD economies which are enjoying robust economic expansion and where income growth looks poised to lift internal consumption and oil demand. African economies are a case in point. While oil statistics in most African countries remain scarce and of low quality, there is growing evidence that African demand has been underestimated and is set to grow relatively steeply, albeit from a low base, in the next few years, turning the continent, despite its persistent governance and other problems, into a new demand frontier.

The US energy supply revolution has helped accelerate an industrial renaissance which accounts in part for the country's relatively stronger pace of economic recovery both in recent months and the foreseeable future. This includes a steep rise in US exports of refined products and a remarkable rebound in petrochemical manufacturing. This stronger growth performance is not expected to lead to a comparable rebound in oil demand, however, due to shifts in the fuel mix, marked efficiency improvements, demographic trends and changing consumer behaviour. New North American supply may accelerate the change in the US fuel mix through greater use of ethane in the petrochemical sector at the expense of naphtha and a shift towards natural gas in transport towards the end of the forecast period. In Europe, on the other hand, the North American supply revolution may indirectly cause adverse impacts on economic growth by undermining the competitiveness of the European industrial sector, particularly its troubled refining and petrochemical industries.

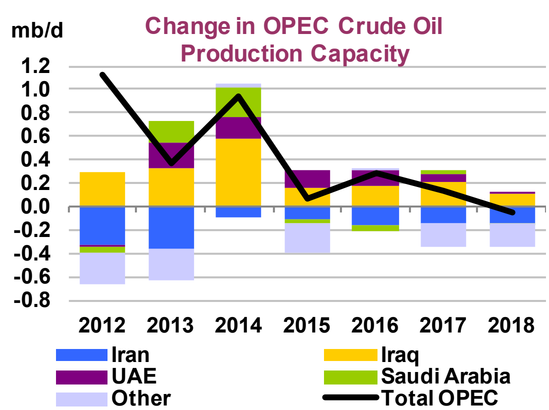
Supply: spreading the benefits of technological breakthroughs

The North American hydrocarbon revolution continues to dominate the supply outlook. As noted, North America is forecast to account for an even larger share of non-OPEC supply than estimated in the 2012 *MTOMR*. While US crude, condensate and natural gas plant liquids (NGL) supplies are booming, this growth should not obscure two concomitant developments: on the one hand, the many challenges facing continued North American supply growth, and, on the other hand, the global impacts of the North American boom on oil companies' asset portfolio management and allocation of capital expenditure around the world. At the same time, the spread of technologies being used to tap tight oil in the US, whether in prospective shale formations or in low-permeability conventional crude plays elsewhere, may improve yields and production worldwide and lead to a broad reassessment of reserves. While little is known at this point about the size and quality of the global tight oil resource, and while it seems unlikely that shale plays or other tight oil formations will be developed outside of the US before the end of the forecast period, unconventional technologies used in shale extraction may nevertheless significantly boost production in conventional plays where they can be applied to enhance recovery.

The challenges facing continued North American production revolve in part around the massive infrastructure and logistical requirements associated with this new production, the uncertainties concerning the legislative and regulatory framework for potential oil exports from the US and Canada, and prospective environmental challenges to gas flaring and wastewater treatment. These challenges may not be as daunting as they appear. The industry has shown flexibility and ingenuity in coming up with new transport links to bring production to market and in tweaking refineries and petrochemical plants to handle the new feedstock. Regulatory and legislative frameworks, in both North America and Europe, also remains uncertain and may offer room for flexibility. But neither should those challenges be dismissed. The impact of logistical bottlenecks on prices may already have played a role in Total and Suncor's decision to cancel their Voyageur oil sands upgrader in Canada, and have no doubt triggered reviews of many other capital expenditure projects. Deep discounts for bottlenecked Canadian grades are an obvious downside for Alberta project economics at current oil prices.

Meanwhile, gains in North American production and technical developments can indirectly affect supply gains elsewhere. On the downside, increases in North American supply, compounded by the impact of host-country policies, may be delaying production and development plans in other regions, particularly Africa, as oil companies and investors prioritise the deployment of new technologies in well developed producing regions, where support services are available and the regulatory environment predictable, over costly mega-projects in frontier areas. On the upside, applying more broadly the technologies that unlocked US tight oil appears to be increasing production prospects in other regions, such as conventional plays in mature areas of Russia and China. The full scope of incremental production that may be unlocked in such a fashion will partly depend both on future technology improvements and on oil prices.

OPEC: challenges ahead



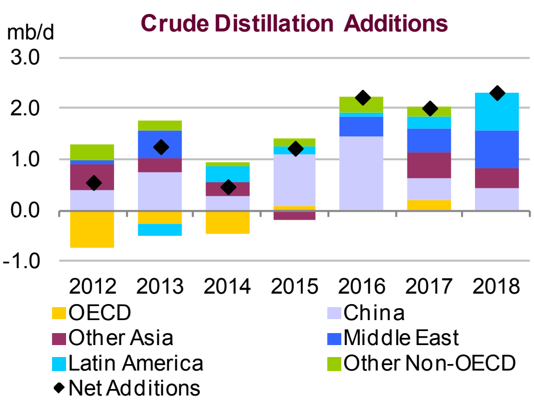
Despite the growth in LTO, OPEC oil will remain an essential part of the global oil supply mix for the foreseeable future. Over the medium term, however, the projection of OPEC capacity growth has been adjusted downwards and reallocated by country. Several OPEC producers are facing challenging social and political transitions. While Libya surprised the markets by the speed with which it was able to restart production after the 2011 civil war, production growth has since stalled. Companies operating in the region face severe security challenges as the central government struggles to assert its authority over the armed militias tasked with providing security to oil facilities. The legal framework of production is also unclear as Libya moves from an established autocratic regime to a less predictable democracy. Security concerns have spread to Algeria following a deadly terrorist attack in January on the In Amenas gas facility, and to Nigeria following kidnappings and attacks by Islamist groups in the North and others in the Niger Delta southern producing region. In Venezuela, the death of long-serving President Hugo Chavez in March 2013 opened another kind of transition period equally fraught with uncertainty.

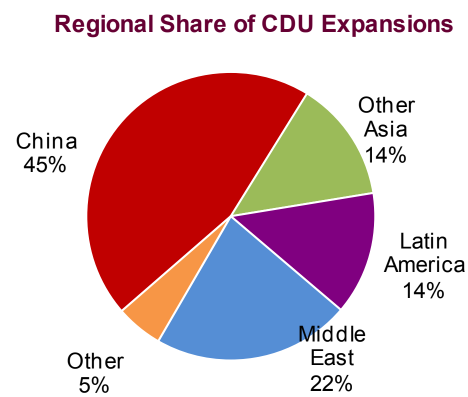
Iraq continues to account for most of the incremental OPEC production capacity over the forecast period, growing by 1.57 md/d to 4.76 mb/d, or near 20% of global crude production capacity growth. But continued above-ground challenges – lingering disagreements between Baghdad and the Kurdistan Regional Government not least among them – are slowing down development, and the growth forecast has been trimmed marginally by around 100 kb/d from the 2012 *MTOMR* forecast. Perhaps symptomatically, Baghdad itself is reviewing its previous, highly ambitious production goal of 12 mb/d by 2017, with 9 mb/d being mooted as a more achievable target.

Global refining: rise of the export titans

The North American supply revolution and the surge in non-OPEC demand continue to redraw the global refining map. In the process, the role of the refining industry in the global supply chain is changing as refineries move closer to the wellhead and growing non-OECD markets and international trade in refined products continues to grow.

In North America, the supply revolution and a downtrend in domestic consumption have helped turn the US, long the world's top importer of refined products, into one of its largest net exporters. Cheap natural gas and 'advantaged' (*i.e.*, discounted from benchmark prices) crude have dramatically increased the competitiveness of US refineries, which also benefit from economies of scale, good logistical links to export terminals (the capacity of which is rising) and state-of-the-art technology. US refiners also have benefitted from fast rising demand and a lack of refining capacity in Latin America, which have provided them with ready export markets for excess gasoline and distillate production. As US output of light products keeps rising, thanks in part to a planned expansion of condensate splitting capacity, US refiners might face increasing international pressure in marketing their surplus, however.



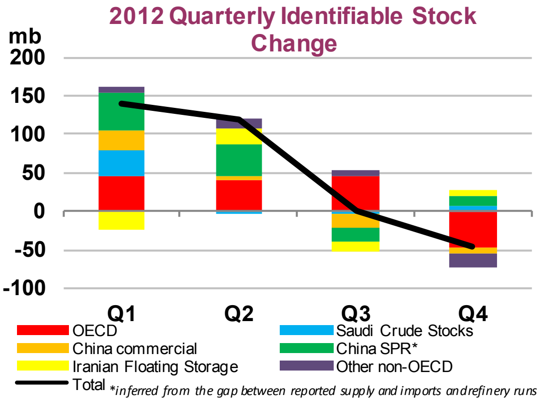


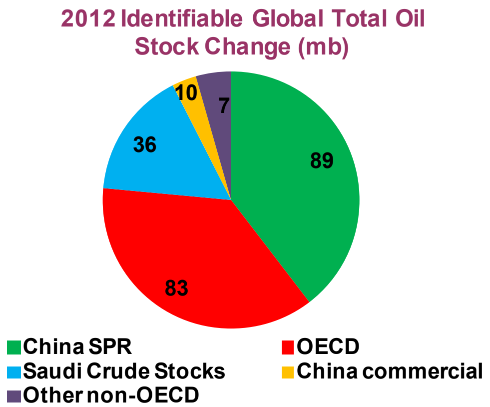
Non-OECD economies already account for a clear majority of global crude distillation capacity, but their share of the refining market is set to rise steeply in the next five years following large increments in the Middle East, Asia, Russia and Latin America. China, in particular, may become saddled with significant excess product output, following ambitious expansion plans at both state-owned refineries and so-called 'tea-pot' plants, a sector increasingly restructured and made more efficient in recent years. Saudi Arabia is also aggressively expanding downstream through large-scale joint ventures with international companies. As global refining capacity expansions outpace upstream supply growth, let alone demand growth, margins and utilisation rates will come under pressure and higher-cost refineries will face increasingly strong competitive headwinds. European refineries are at particularly high risk of closure over the forecast period. The rise in North American LTO production, coupled with cheap US shale gas, will greatly contribute to these pressures, as it will both make US export refineries more competitive and steeply increase excess light-product supply (gasoline and naphtha), causing US and European refineries to compete directly for export market outlets.

European refinery closures would likely carry significant implications for both energy security and prices. They would likely make Europe more dependent on product imports, lengthen European supply routes, increase their vulnerability to disruptions and raise European reliance on import terminals and product storage facilities, notably for jet fuel and gasoil. In so doing, they may also result in higher price spreads between European markets and exporters, so as to pay for long-haul transport costs, while price differentials or time spreads between low- and high-demand periods may widen to cover storage costs. Increased European reliance on trading houses and third-party suppliers may also leave a growing share of European supply in the hands of market participants with a different set of incentives than those of refiners. Whereas refiners have a clear interest in maximising production and plant utilisation, traders have a different mix of fixed assets and their strategy and market behaviour thus tend to respond to other signals, such as arbitrage opportunities or market volatility.

Trends in stocks and storage capacity

Not surprisingly, the storage industry has undergone massive change and is expected to remain very dynamic in the next five years as global storage capacity continues to expand in response to shifts in supply and demand. In the US, shifting supply and demand patterns have been associated with a broad restructuring in the storage industry. Integrated oil companies and independent refiners have in recent years spun off their storage and transportation arms as stand-alone profit-seeking companies rather than integrated cost centres. Those newly minted US midstream companies, typically set up as Master Limited Partnerships with substantial tax incentives, have presided over a rapid expansion in transport and storage capacity in the US, both in the Midwest and Gulf Coast to support the gathering and distribution of new oil and gas supplies, and also on the East Coast and in the Caribbean, where the distribution of refined products has undergone significant transformation.





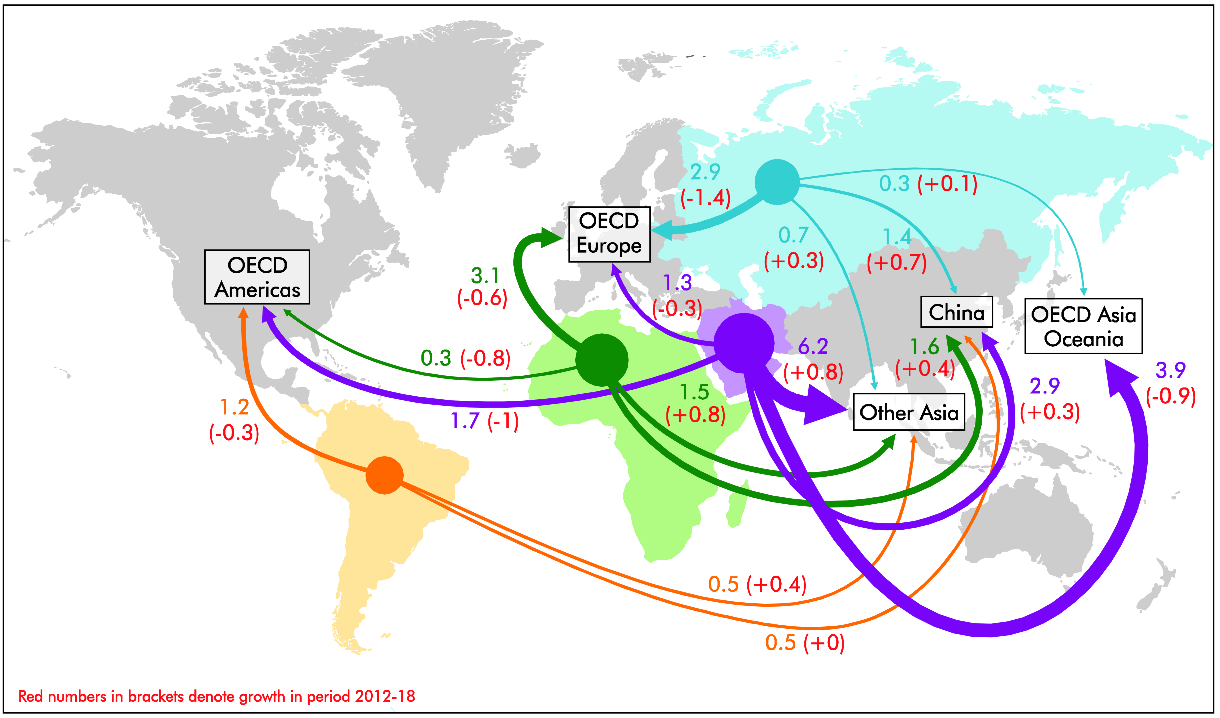
But the most dramatic expansion of storage capacity has occurred in non-OECD economies, where continued growth is expected over the medium term. This includes both strategic reserves, principally in China but also in other Asian economies, as well as commercial storage, associated with refinery capacity expansion and changing import and export requirements, in a broad range of economies, including Asia, Russia and Africa. Storage infrastructure is also on the verge of potentially significant change in Northwest Europe, reflecting refining capacity attrition, shifts in North Sea and Russian crude supply and the evolution of long-haul crude and product trade. There are plans by Russian market participants to set up the Amsterdam-Rotterdam-Antwerp centre as a trading hub not just for regional distribution but also for long-haul, global trading operations. Non-OECD storage capacity is, generally speaking, a proverbial black box for international oil statisticians. This Report attempts to shed some light on recent and medium-term forecast developments based on open-source information. Much more work is required in this direction.

The shifting oil trade map: non-OECD countries overtake OECD crude imports

As North American refining activities are increasingly supplied with US and Canadian crude while more and more Middle Eastern crude is refined domestically, crude trade is expected to decline over the next five years. Nevertheless, the non-OECD share of international crude imports looks set to increase and push through 50% by the end of the forecast period. Rising Asian imports may fuel support for the establishment of new, internationally traded crude benchmarks in Asia and the Middle East. Meanwhile, long-haul trade in refined products is forecast to increase, partly offsetting the decline in crude volumes.

Crude Exports in 2018 and Growth over 2012-18 for Key Trade Routes

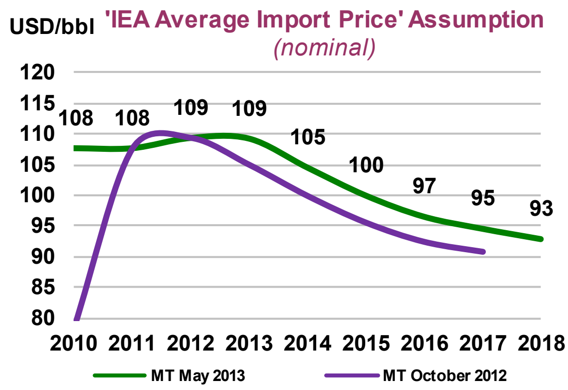
(million barrels per day)



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.

A note on prices

The International Energy Agency does not forecast prices as a matter of principle. The price assumptions used in this forecast for modelling purposes are derived from the forward curve in Brent futures prices, in keeping with the practice of other institutional and commercial forecasters. Recent and expected changes in price formation are not specifically addressed in this Report, although shifting oil supply, demand and trade patterns carry potentially significant implications for prices and



price spreads between products and geographical markets. New sources of supply and fast-growing consumption and import centres may also lead to the emergence of new benchmarks. China in particular is mulling the launch of a new international futures market, which may provide market participants with hedging and trading instruments based on a new locally devised benchmark index price. Finally, regulatory changes affecting commodities and financial markets have had and will continue to have substantial consequences for the oil market, including, but not limited to, shifts in trading and hedging strategies by market participants and changes in the cast of financial institutions active in physical and paper trading. These changes will be discussed in future editions of the *MTOMR* and of the monthly Oil Market Report (OMR), and may also be addressed in ad hoc notes and other publications.

DEMAND

Summary

- **Global oil demand growth is forecast to average 1.1 mb/d (1.2%) per annum, over the next five years,** for an aggregate increase of 6.9 mb/d from 2012 to 2018, rising to 96.7 mb/d. Growth will remain subdued in 2013, then gain momentum in 2014-15 on stronger economic expansion, and slow down again in 2016-18 on efficiency improvements and fuel switching.

- **The regional spread of demand continues to shift to non-OECD economies, especially Asia.** Non-OECD demand is forecast to exceed that in the OECD as early as 2Q13 and expand by an average of 1.4 mb/d (3.0%) per annum in 2013-18, led by Asia (700 kb/d), the Middle East (260 kb/d), Africa (160 kb/d) and Latin America (150 kb/d). In contrast, demand in the OECD is projected to decline by 250 kb/d a year (-0.6%).

- **The forecast of oil demand growth is little changed since the 2012 *MTOMR*.** The 2017 estimate is trimmed by 95 kb/d, reflecting marginally lower 2013 demand than expected and slightly reduced expectations of economic growth. Fuel switching is also projected to make a marginally bigger dent on oil demand than previously forecast.

Global Oil Demand (2012-18), million barrels per day

	1Q12	2Q12	3Q12	4Q12	2012	1Q13	2Q13	3Q13	4Q13	2013	2014	2015	2016	2017	2018
Africa	3.5	3.5	3.5	3.6	3.5	3.7	3.7	3.7	3.7	3.7	3.9	4.0	4.2	4.3	4.5
Americas	29.7	30.2	30.5	30.5	30.3	30.2	30.2	30.7	30.6	30.4	30.6	30.6	30.7	30.7	30.7
Asia/Pacific	29.7	28.8	29.0	30.3	29.4	30.4	29.4	29.3	30.6	29.9	30.5	31.3	32.0	32.7	33.3
Europe	14.3	14.5	14.5	14.3	14.4	13.8	13.8	14.3	14.4	14.1	14.0	13.9	13.9	13.8	13.7
FSU	4.4	4.4	4.6	4.6	4.5	4.4	4.5	4.8	4.8	4.6	4.8	4.9	5.0	5.1	5.3
Middle East	7.2	7.8	8.1	7.5	7.6	7.4	7.9	8.3	7.7	7.8	8.1	8.4	8.6	8.9	9.2
World	**88.9**	**89.2**	**90.2**	**90.8**	**89.8**	**89.9**	**89.5**	**91.1**	**91.8**	**90.6**	**91.8**	**93.1**	**94.4**	**95.6**	**96.7**
Annual Chg (%)	0.5	1.6	0.5	1.3	1.0	1.1	0.3	0.9	1.1	0.9	1.3	1.4	1.4	1.3	1.1
Annual Chg (mb/d)	0.5	1.4	0.4	1.1	0.8	1.0	0.3	0.9	1.0	0.8	1.2	1.3	1.3	1.2	1.1
Changes from last MTOGM (mb/d)	-0.34	0.25	-0.15	0.21	-0.01	-0.19	-0.01	-0.12	0.23	-0.02	-0.03	-0.05	-0.07	-0.09	

- **Africa is emerging as the latest demand frontier.** Historical African oil demand has been revised upwards, with 105 kb/d added to the 2012 estimate over the previous *Report*. Demand growth in the continent is expected to pick up steam through the forecast period, with growth averaging 4.0% per annum 2012-18, albeit from a low base (3.5 mb/d in 2012). Demand assessments for the region remain, however, plagued by the scarcity and low quality of data.

- **Transportation fuels remain the key driver of global oil demand, but natural gas starts making inroads in the transportation fuel market,** lifting its share of global road transport fuel demand to 2.5% by 2018, from 1.4% in 2010. China and the US drive the momentum for gas in transport. But the required infrastructure build will likely take up much of the forecast period, with large-scale gains more likely to occur later on.

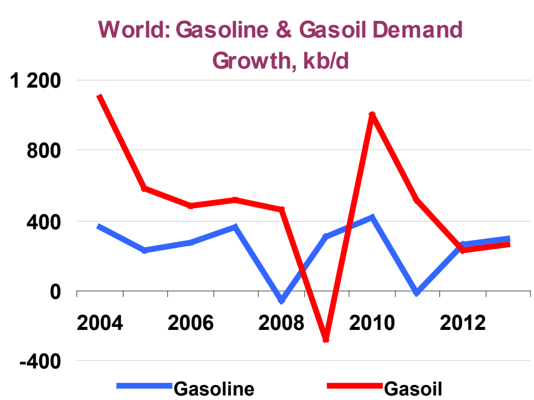
- **The downside risk to demand persists in the medium term as the global economic recovery remains fragile.** European demand is especially weak, in line with expectations of economic growth. Chinese oil consumption growth remains more subdued than in the previous decade, as the Chinese economy continues to mature. The US economy shows stronger growth than the rest of the OECD, thanks to low-priced natural gas and fast-growing domestic oil production, but the demand impact of economic growth is offset by efficiency gains and changing consumer behaviour.

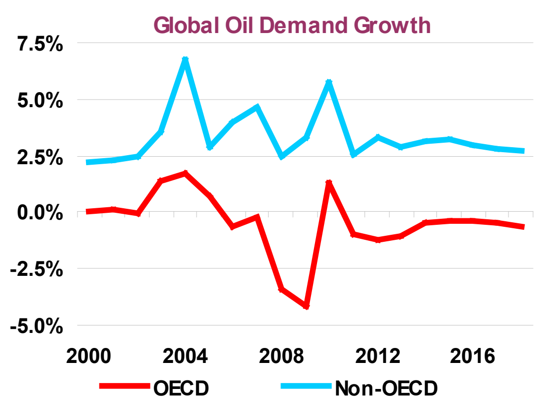
Overview

Global oil demand growth is projected to average 1.1 mb/d (1.2%) annually through the forecast period, little changed from the 2012 *MTOMR*. Global demand is expected to reach 96.7 mb/d in 2018, up 6.9 mb/d from 2012 levels. Growth is forecast to remain subdued around 795 kb/d in 2013 as global economic sluggishness continues, but to pick up momentum in the following two years, along with the economy, peaking at around 1.3 mb/d in 2015-16. It is then projected to decelerate through to 2018, easing back on a combination of efficiency gains and fuel switching.

While the global economic outlook has improved, challenges still abound. Aside from the economy, other factors combine to restrain the demand outlook. Those include a global drive towards more efficient energy usage (in part as a consequence of the relatively high oil price environment) and, at the margins, some degree of fuel switching out of oil, including the gradual restart of idled nuclear power generation in Japan, and the first inroads of natural gas in the transport sector in the US and China.

In addition, the maturation of the Chinese economy, long the main engine of global demand growth, sets the stage for somewhat more subdued demand growth there. Between 2003 and 2007, the Chinese economy expanded by an average 11.7%, but is forecast to slow to around 8.4%, 2014-18, and could be even slower according to the Chinese five-year plan target of 7.5%. Each of these topics is addressed in detail in this *Report*.



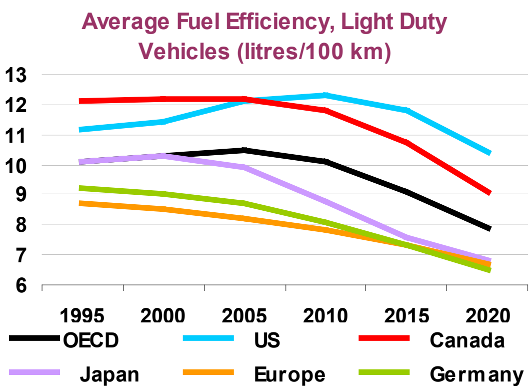


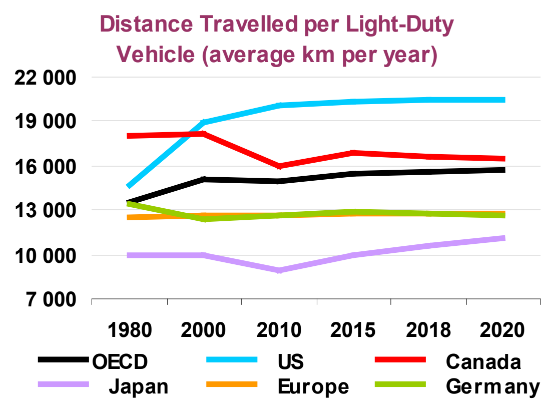
OECD

The demand trend for the OECD appears entrenched in a long-term structural decline which is expected to persist through the forecast. Overall, OECD demand is forecast to contract by 0.6% per annum from 2012 to 2018, led by steep declines in residual fuel oil and gasoline. Demand for residual fuel oil is forecast to contract by around 3.5% per annum, through to 2018, as tighter coastal shipping regulations force many vessels to switch to lighter fuel such as gasoil, and potentially natural gas. Efficiency gains and changing consumer behaviour are expected to dampen demand for jet/kerosene and gasoline.

Whereas the 2012 *MTOMR* highlighted a divergence in the pace of economic recovery between OECD and non-OECD economies, a split has since emerged within the OECD group itself between, on the one hand, the US, where cheap and abundant natural gas and 'advantaged' (*i.e.* discounted) domestic crude have helped stimulate the economy, and, on the other hand, the euro area, which remains bogged down by protracted sovereign debt issues and stagnant growth. Economic weakness has spread in Europe from the so-called peripheral economies such as Italy and Spain to 'core' economies such as Germany and France. Poor economic performance in Europe clearly is a drag on oil consumption. Even in the US, where the economy is performing better, oil demand growth is expected to remain in contraction. That is because income gains are projected to be offset by other factors, such as improving vehicle efficiency and changing consumer behaviour. Natural gas penetration of the transport sector, starting with bus, freight and rail, could also help displace US diesel demand at the margin, though transport gas is not expected to become a reality on a truly large scale until after the forecast period.

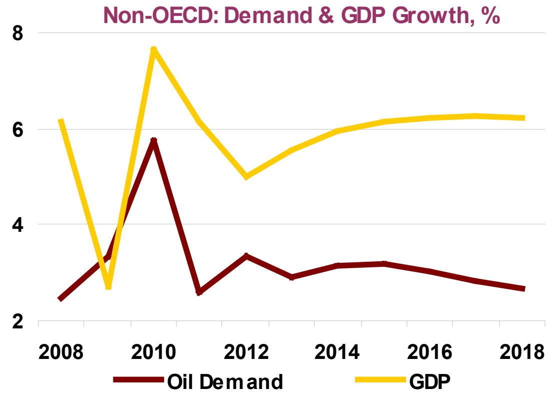
Trends in OECD end-user demand for refined products, which is generally contracting, should not be confused with the region's more diverse patterns of crude demand from refiners. In the US, refining activity, supported by growing volumes of US light, tight oil and discounted heavy Canadian crude, helps not only to meet domestic demand but also supports rising exports of refined products. In just a few years, the US, long the world's largest net product importer, has become one of its top two net exporters. Europe is a different story. There, a troubled refining industry faces increasing competitive pressures from the US, the Middle East, Russia, China and India. With many European refineries at risk of closure, European refining capacity – and thus crude demand – looks set to contract even faster than product demand, increasing the region's import dependence. This does not apply uniformly across the continent, however. Refineries in Southern Europe (Spain and Portugal) have been performing better than average and have managed to increase their product exports, thanks to earlier investments in upgrading capacity.

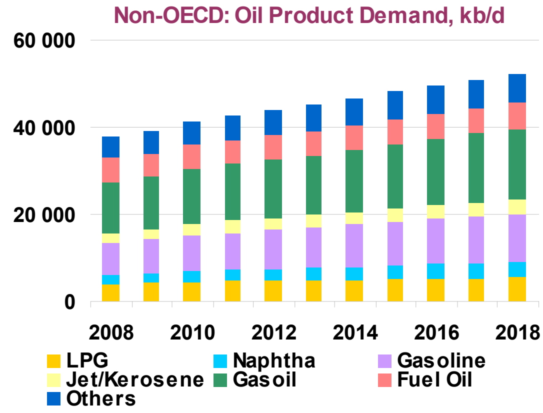




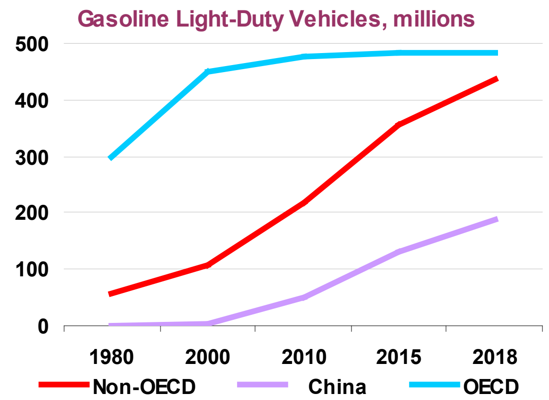
Non-OECD

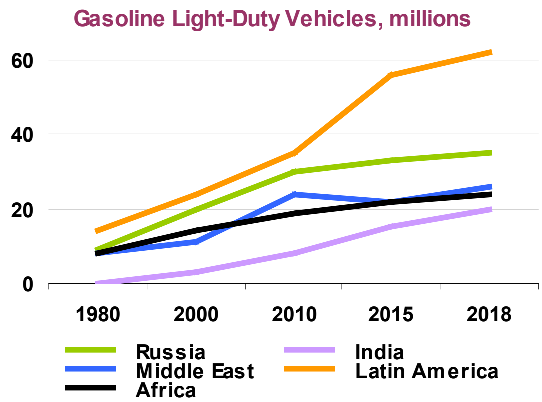
Emerging and recently industrialised markets have dominated the global growth spectrum in recent years, thanks both to stronger economic growth and to higher oil intensities than in advanced economies. Non-OECD demand is estimated to have overtaken OECD demand in 2Q13 for the first time and is projected to keep gaining market share at the expense of the OECD through the forecast period, rising from 49% of global demand in 2012 to 54% in 2018.





Within the forecast, non-OECD oil demand growth continues to outpace OECD economies, with the relative non-OECD growth rate maintaining a near-3.5% premium over the OECD through the forecast. Non-OECD oil demand growth averages out at roughly 3% per annum, 2012-18.





Gasoline is expected to lead non-OECD demand growth through the forecast period on the back of rising vehicle ownership. In 2012, strong gasoline-led non-OECD demand growth and a contraction in the OECD caused a temporary shift in the distribution of global demand growth by product: whereas demand for middle-distillate (gasoil) had in earlier years risen faster than for any other product, in 2012 gasoline demand expanded slightly faster than gasoil, a trend that may be replicated in 2013. Relatively weak industrial activity in 2012 kept gasoil demand in check. Near-recessionary conditions in many OECD nations, notably Europe and Japan, depressed OECD gasoil demand to such an extent that it fell in absolute terms, down by 240 kb/d on the year. This, combined with relatively subdued non-OECD gasoil demand, led to global gasoil demand growing at less than half of its year earlier expansion. In contrast, gasoline demand saw an accelerating trend in 2012, up by 255 kb/d. The two regional markets with amongst the highest dieselisation rates in the transport sectors were also the two that performed worst economically, OECD Europe and OECD Asia Oceania. This factor, coupled, with the clear preference for gasoline in still thriving Chinese and Saudi Arabian transport sectors, boosted gasoline demand to such a degree that it outpaced gasoil. This line of reasoning is forecast to hold in 2013, before reversing thereafter as the strengthening industrial outlook worldwide supports a notable ramp-up in gasoil demand.

The outlook for non-OECD demand is not without downside risk, however. The fallout from the Arab Spring could significantly dent Middle Eastern and North African demand if it results in continued political and social instability. Likewise, a sustained decline in crude oil prices could dig into export revenues in oil exporting countries, adversely affecting their internal demand growth. But on the flipside, downward pressure on crude prices could also stimulate oil demand from other non-OECD, especially oil-importing economies. Foremost among the non-OECD regions poised for growth, albeit from a low base, is Africa. While the poor quality and scarcity of African oil data have long clouded the continent's oil demand outlook, it has become clear that the region's demand has long been underestimated, and may be set for robust growth over the forecast period.

Underlying economic assumptions

The world economy has been forced to endure a tumultuous journey these past five years, with its heaviest recessionary slump since the 1930's dominating the initial two years of this sample, *i.e.* 2008-09, before a dramatic resurgence took hold in 2010. Many observers thought that to be the end of it, but they hadn't prepared themselves for the anaemic growth trend that was to follow.

The assumptions of economic growth underpinning this outlook are derived from the International Monetary Fund's (IMF) *World Economic Outlook* (*WEO*) of April 2013, which forecasts global economic growth of 3.3% in 2013 and 4.0% in 2014, gently accelerating through to 4.5% by 2018. It is, thus, only by the end of the outlook that economic growth is back up to speed with its pre-recessionary trend.

As macroeconomic momentum modestly accelerates throughout the forecast, so does oil demand growth. But the latter is expected to lag broader economic growth somewhat, reflecting the impact of efficiency gains and some measure of fuel switching out of oil, especially at the tail end of the forecast period.

On balance, the global economic growth assumption behind this forecast is not all that different from the one underpinning the 2012 *MTOMR*, but the regional spread of growth has diverged. The idea of a three-speed recovery has now replaced the IMF's earlier assumption of two-speed economic growth. Emerging and newly industrialised economies still do much better than mature OECD economies. Within the latter group, however, a clear split has emerged between those economies that are seemingly stuck in a rut and those, such as the US, that are showing clear signs of recovery.

Having endured a tough 2012, the IMF is forecasting a gradual reacceleration in Chinese macroeconomic momentum, with GDP growth likely back to around 8% by 2013, and picking up towards 8.5% by 2015. Other emerging market nations, such as India, Vietnam, Indonesia and much of Africa, are also forecast to rise strongly through the forecast. The two-speed nature of the OECD outlook has the euro area still declining in 2013, down by 0.3% before gently accelerating thereafter, whereas US GDP growth averages out at 1.9% in 2013 and accelerates through to around 3.5% by 2015.

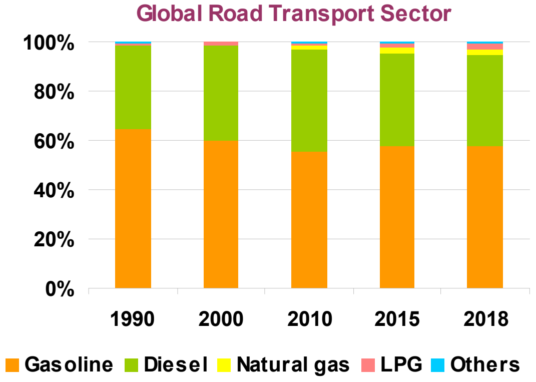
A number of risks remain very much entrenched in the economic outlook. In particular, the IMF highlighted concerns regarding "the absence of strong fiscal consolidation plans in the US and Japan". The *WEO* also notes that "high private sector debt, limited policy space, and insufficient institutional progress in the euro area" remain a potential trigger for future problems.

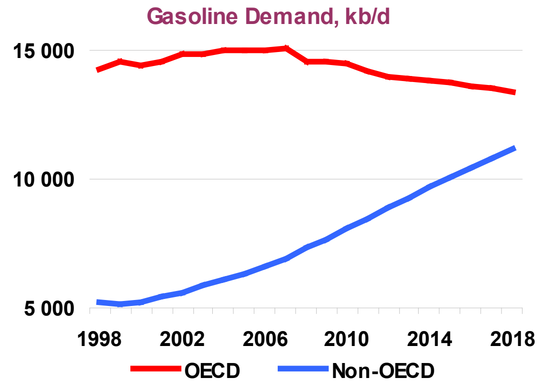
These downside risks to the global economy directly translate into significant downside risks to this demand forecast. The IMF remains concerned with the distortions that exist today "from easy and unconventional monetary policy" in many OECD nations and "over investment and high asset prices" across large swathes of the non-OECD. The current IMF outlook assumes that these issues will be relatively successfully circumnavigated. Yet there remains a great deal of uncertainty about the speed of global economic recovery, and even a temporary crisis could go a long way in slowing macroeconomic momentum. Today's economic environment is unusually precarious and, hence, adds a degree of strenuousness to our usual emphasis on the inherent uncertainty of oil demand forecasts.

Transport sector

Oil will remain the world's foremost **transportation fuel** through the forecast period to 2018, led by gasoline and gasoil, but natural gas is expected to make significant inroads as a transport fuel, increasing its share of road transport demand to 2.5% by 2018 from 1.4% in 2010 and just 0.2% in 2000. Oil clearly maintains its dominance of the road transport sector at 96.4% in 2018 (from 97.8% in 2010). The technology already exists for natural gas propulsion to take a more significant role in the road transport sector, and in many markets relative price differentials already look supportive of switching, but other problems exist today. Fuel-switching to natural gas for transport requires a substantial infrastructure build-up, which could begin to happen in a big way over the forecast period but regardless may not bear fruit until later. While this infrastructure development could eventually pave the way for substantial displacement of oil by natural gas in the transport sector, truly meaningful fuel switching is not expected to occur until after the end of the forecast period.

Gasoline is expected to remain the transportation fuel of choice through the forecast period. But growth in gasoline demand is expected to slow down significantly in 2012-18, to around 1.2% per annum, to 24.5 mb/d, compared to average growth of 1.6% in 2001-07, prior to the 2008-09 recession. The forecast is curtailed by IEA assumptions that the global vehicle fleet becomes increasingly efficient (see *Average Fuel Efficiency* chart), through to 2018.

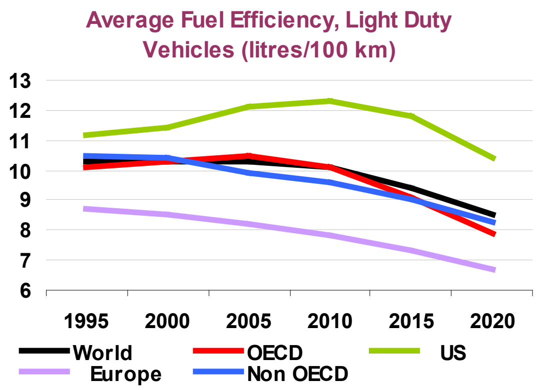


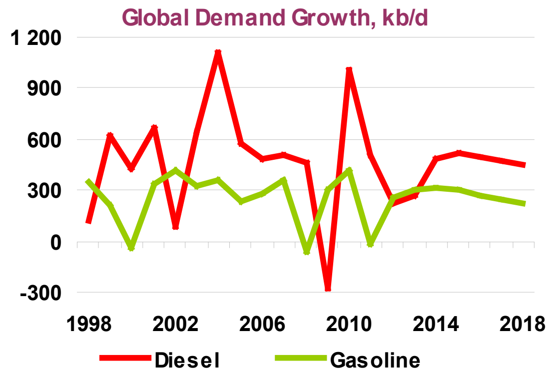


Slowing but persistent growth in global gasoline demand growth should not conceal clearly diverging regional trends. Emerging markets and newly industrialised economies are expected to show steep gains in gasoline demand, but consumption elsewhere is in a protracted downtrend. In the non-OECD economies, aggregate demand is forecast to expand by 3.8% per annum from 2012 to 2018, versus 0.7% contraction in the OECD. Notably robust non-OECD gasoline demand gains are foreseen in India, China and Africa, respectively rising by an average of 5.4%, 5.0% and 4.5% per annum, 2012-18. The key difference being the rapid clip at which annual growth of the non-OECD vehicle fleet outpaces OECD: 10.6% versus 1.7%, 2010-15; 7.7% to 0.8%, 2015-18. As countries move up the income curve, their demand for motorised transportation goes up, but demand tends to plateau or even inch down after individual incomes reach a certain level. There is thus a much closer correlation between growth in GDP and gasoline demand in emerging markets than in mature OECD economies. Environmental legislation and tax policy also can act as a brake on gasoline demand growth in OECD countries, more so than in emerging economies. Gasoline demand in non-OECD economies is not expected to overtake OECD demand, but the two are coming closer.

Total Light Duty Vehicle Stock, millions

	1980	2000	2010	2015	2018
World	370	625	840	1 025	1 130
OECD	310	500	585	635	650
Non-OECD	60	125	255	390	480





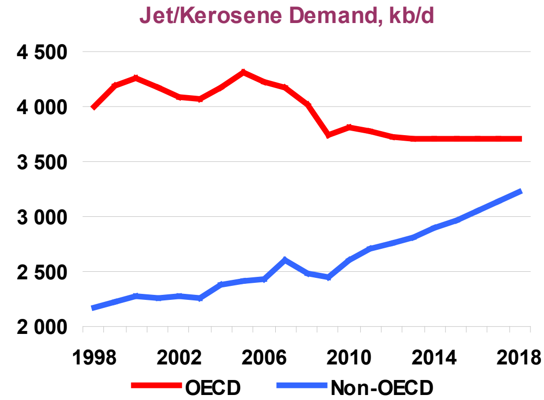
Gasoil/diesel demand is expected to grow faster than gasoline demand, 2012-18, but from a lower base. In aggregate, gasoil demand is forecast to expand by 2.7 mb/d (or 1.6% per annum), with all of the gain (*i.e.* 2.7 mb/d) attributable to non-OECD economies. Towards the end of the forecast period, diesel demand faces growing competition from natural gas as the latter starts making inroads into the transport fuel market, particularly in the Chinese and US freight, rail and bus transportation markets.

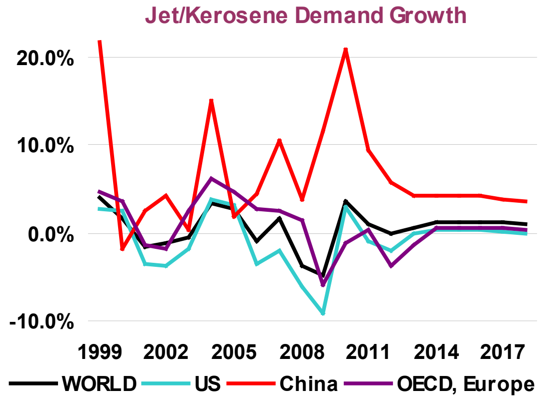
Average Travel Per Light Duty Vehicle (km per year)

	1980	2000	2010	2015	2018
World	13 466	14 206	13 813	14 656	14 525
OECD	13 580	15 052	15 008	15 446	15 578
US	14 696	18 959	20 108	20 310	20 432
Europe	12 573	12 672	12 612	12 792	12 772
Non OECD	12 876	10 780	11 094	13 373	13 107
China	11 300	9 229	11 863	12 000	12 000

Air travel is the second largest transport sector after road. The sector predictably struggled through the so-called Great Recession of 2008-09 as airline traffic took a nosedive. Supported by the more robust macroeconomic outlook, demand for air travel is projected to show modest growth over the course of the forecast period to 2018. On average, demand for jet/kerosene is expected to increase by an average 1.1% annually, 2013-18.

Like road transport demand, air transport shows regionally diverging trends: OECD jet/kerosene demand is forecast to decline by an average of 0.1% per annum, 2012-18, while non-OECD consumption gains roughly 2.6% per annum. In the non-OECD sector, particularly strong gains are projected in China (+4.1% per annum), Africa (+3.9%) and the Middle East (+3.0%). These last two regions are underpinned by strong recent airline sales figures; manufacturer Airbus, for example, reports 9% of the firm's global deliveries in 2012 to the Middle East and North Africa region. The Middle East will account for roughly 10% of Airbus' sales over the next two decades, according to the company's forecasts.





In contrast, Europe was the worst performing global jet fuel market in 2012 and is forecast to keep struggling in 2013. Air safety agency Eurocontrol predicts a 1.3%-to-2.9% drop in the number of flights in European airspace in 2013, before a modest recovery is staged in 2014. This estimate is in line with this *Report's* projected 1.3% decline in jet/kerosene demand in 2013 followed by a steady uptick through the remainder of the forecast period, averaging out at 0.5% per annum, 2013-18. Eurocontrol reported a 2.7% decline in European average daily flight movements in 2012, despite reports from the Association of European Airlines of 2.2% more passengers being carried. Diverging trends in jet fuel demand and passengers carried likely reflects improvements in fuel efficiency and fleet management. Faced with exceptionally high average jet fuel costs and large swings in demand since the terrorist attacks of September 2001, the airline industry has diligently pursued a broad range of fuel savings options, including the gradual replacement of its fleet with more efficient aircraft and policies to reduce the number of empty seats on commercial flights.

The **shipping industry** is expected to keep growing through the forecast period, raising bunker fuel demand by 255 kb/d to 4.1 mb/d, albeit with a changing product mix. The industry accounted for roughly 6% of total global oil demand in 2010, up from 5.2% back in 2000 as the expansion in global trade flows more than offset the impact of vessel efficiency gains. Strengthening efficiency gains, and some movement to alternative fuels, should see its market share fall below 5% by 2018.

Residual fuel oil continues to dominate the shipping industry, accounting for roughly 87% of total bunker fuel demand in 2010, but has recently lost market share to cleaner fuels such as gasoil (13% of global bunker fuel demand in 2010, at 550 kb/d). OECD countries have already tightened environmental standards in coastal waters and plan to further control bunker fuel emissions over the forecast period. Emission Control Areas (ECA) were set up to control the quantity of air pollutants in sensitive high-volume shipping zones such as the North Sea, the Baltic Sea and coastal areas off North America, where the sulphur content of fuel burnt must currently not exceed 1%. That ratio is legislated to fall to 0.1% sulphur by 2015. Outside the ECA there are also minimum sulphur requirements, currently set at 3.5%, which have been agreed to fall to 0.5% by 2020 (although a deferral to 2025 remains a possibility, subject to a review to be completed by 2018).

The lower-sulphur content of most gasoil will increase its market share in the shipping industry at the expense of residual fuel oil. Should natural gas make further inroads in the form of liquefied natural gas (LNG) into marine transport markets, both residual fuel oil and middle distillates could lose market share, however. Tightening environmental standards for ships and the availability of competitively-priced natural gas in North America could hasten that prospect. This *Report* does not anticipate that LNG will become a major marine transport fuel by 2018, but highlights the strong potential for gas in marine transportation over the longer term.

Transport gas: dawn of a new age?

The US shale gas revolution has opened up new markets for natural gas and encouraged fuel switching as consumers seek to leverage the cost advantage of gas and producers search for new outlets. Already the US shale gas boom has dramatically altered the fuel mix of two key sectors: power generation and petrochemicals. Gas in transport, long a distant prospect, now seems much closer to becoming a reality. Its deployment would offer much larger opportunities for oil demand reductions than any other sector. In addition, those prospects are not limited to the US.

Fuel switching to natural gas in the US power sector has had only minimal impact on oil demand, due to its already diminutive size and the fact that natural-gas penetration, however rapid and significant, has mainly come at the expense of coal. The shale gas revolution in the US resulted in an abundance of natural gas and hence, in declining prices. Annual average Henry Hub gas prices went from USD 8.15 per million British thermal units (MBtu) in 2010, down to USD 4 per MBtu in 2011 and USD 2.75 per MBtu in 2012. This caused a switch from coal to gas in power generation. Notably, in 2012, whereas net gas generation increased by 215 terawatt hours (TWh), net coal generation decreased by 215 TWh.

In the petrochemical sector, the shale gas and light tight oil revolution has displaced naphtha, long the industry's feedstock of choice, and replaced it with ethane. As the latter is included in our oil balances as LPG, petrochemical fuel switching has merely replaced one oil product with another. Associated efficiency gains – ethane has better ethylene yields than naphtha – have been offset by increased cracking activity, as cost pressures have sparked an unexpected revival of a long troubled industry.

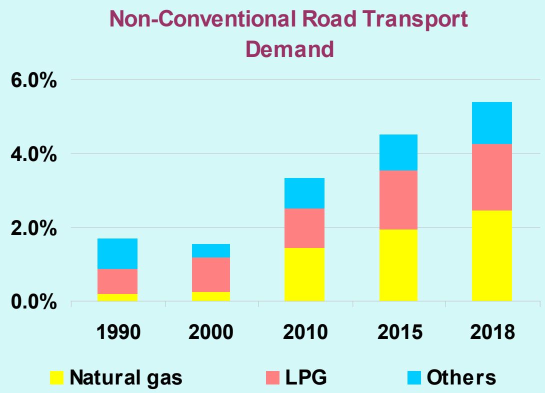
Gas penetration in the transport sector is a potential 'game changer' but is likely to occur in stages. In the US, the cost advantage of gas and the abundance of supply are rapidly building momentum towards erecting the distribution infrastructure needed to allow the large-scale use of gas as a transport fuel. City buses, freight and rail are likely to become the first sectors to witness significant natural gas penetration. Cost advantage is less of a factor in China. There, government policy and environmental concerns are the top drivers, specifically the need to address the severe air pollution of congested cities. Gas conversion of part of the country's huge truck fleet could result in relatively large-scale oil displacement. Other countries with the potential to make big swings over to gas include the resource-rich nations such as Australia, with the world's two biggest miners, Rio Tinto and BHP Billiton, both reportedly considering gas-powered trucks at their mining facilities. In the next five years, we estimate conservatively that the share of gas in road transport could rise to around 2.5%, from 1.4% in 2010. This would displace approximately 0.5 mb/d of diesel and gasoline demand.

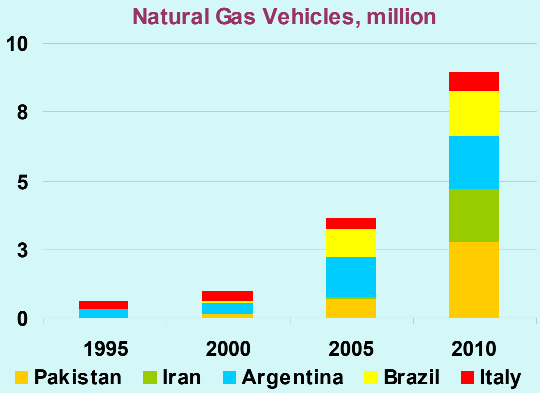
Prices and government support will play an important role in setting the pace of gas penetration in transport. The technology already exists. The US Center for Climate and Energy Solutions estimates that utilising current conversion technologies, typically 10 million cubic feet (mcf) of gas are required to produce the equivalent energy of one barrel of oil products. Based on a US natural gas price of around USD 4 per mcf, this suggests that gas in transport would be competitive at an oil price of USD 40 per barrel, excluding infrastructure costs. Should the US shale gas boom be replicated elsewhere, price pressures for transport gas would clearly build up. This report does not assume significant growth in shale gas outside of the US during the forecast period, however.

Transport gas: dawn of a new age? (continued)

Substantial government support may be required if gas is to really take-off as a transport fuel. Support policies would likely be critical to help fund and deploy the necessary refuelling station infrastructure. Financing vehicle conversions and incentives for new gas-powered vehicle purchases would also help. Such support may not be forthcoming in OECD economies under current budgetary pressures.

Pakistan is a good example of how government aid can help foster the conversion of the transport fleet to natural gas, although prolonged support has been in place for over fifteen years. The International Association for Natural Gas Vehicles cited the Pakistani share of natural gas vehicles at 61.1% in 2010. Many of these vehicles can, however, still run on gasoline. More recently, gas shortages and reports of tanker explosions have cooled Pakistan's desire for transport gas. In 2012, the Pakistani government announced that it was phasing out gas-in-transport, going as far as banning future conversions and reportedly considering closing refuelling stations within the next three years. The quality of the gas-powered car pool in Pakistan is, however, exceptionally low and its experience should not be held up as a deterrent to other countries.





The US heavy freight sector is a good candidate for conversion to natural gas. The *Northern Colorado Gazette* reported on a number of successful LNG conversions in the trucking sector in 2012, with savings of USD 25 000 a year cited per truck. As long-haul trailers travel mostly on interstate highways, building the network of LNG refuelling stations to serve them would be relatively easy. The American Trucking Association is lobbying for government support to deploy such LNG corridors along US highways. Shell has announced two projects to supply LNG to heavy trucks and large ships in North America. A number of major US couriers, including Federal Express and UPS, are also reportedly switching to Compressed Natural Gas (CNG), the ideal choice with gas conversions in smaller vehicles. So are several large garbage collectors, such as Waste Management in the US, which will reportedly use CNG for 80% of its new collection trucks. Many US industries, such as freight, couriers, waste management and bus services are already amongst the early adopters of gas-in-transport, as their depot-based refuelling practices facilitate the switch.

The highly concentrated US rail sector is also considering adopting natural gas, in the form of LNG, to power train engines. Two major US railcar producers, GE and Caterpillar, are reportedly planning to produce a gas-powered locomotive engine. All the major railroad companies are thought to be considering switching from diesel to gas. Later this year, BNSF will reportedly begin testing a small number of locomotives using LNG on its system.

Tighter environmental legislations offer potential inroads for natural gas into the shipping industry. While the cost-competitiveness of US gas would support the switch in North America, price is not the only driver, nor is the potential attraction of gas for marine transport limited to the US market. Using LNG as bunker fuel could be a way to address tightening emission standards for coastal traffic. Pressure to switch is anticipated near-OECD coastal routes, as a means to address the tighter bunker-fuel sulphur regulations that apply there.

Transport gas: dawn of a new age? (continued)

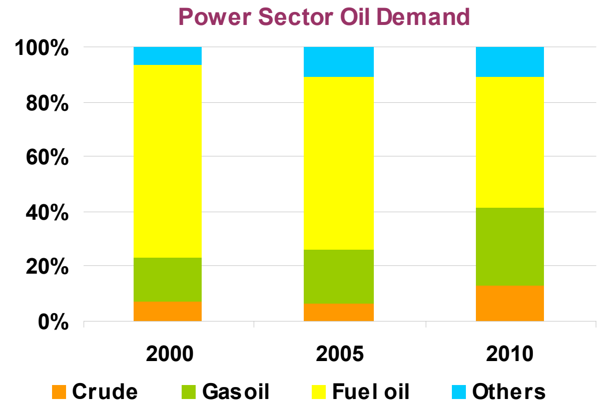
Gas will certainly make some inroads into the shipping industry, dampening OECD fuel oil sales, as shippers increasingly order LNG-enabled vessels. Dutch ship-owner Anthony Veder ordered two of these dual-fuel ships, due to be delivered in 2014, to be used in ECA. Evergas, a Danish-based gas carrier, has placed an order for an undisclosed number of Chinese made dual-fuel LNG vessels, to be delivered 2015. Germanischer Lloyd, the maritime services company for example, recently published its findings on LNG-shipping, claiming that using LNG as a ship fuel would reduce sulphur oxide emissions by between 90% and 95%, a level that will become mandatory within ECA waters from 2015. The Interlake Steamship Company has announced plans to convert its vessels to use LNG, the first company in the US Great Lakes to do so.

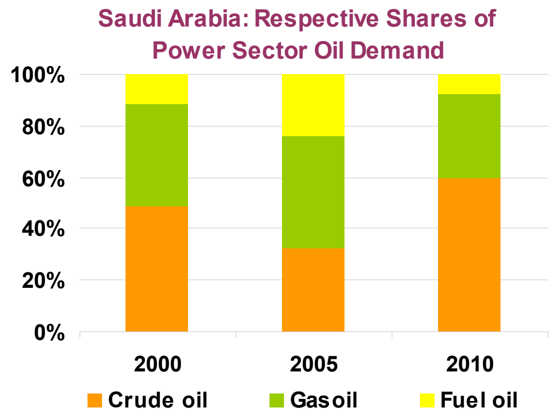
China is also contemplating transport gas as a means to address mounting air pollution challenges in its largest cities. Gas transport initiatives and policy targets are being undertaken at the national, provincial and municipal levels. The city of Beijing has thus embraced gas-powered buses as a way to cut emissions, ordering over three thousand in 2013, taking the total gas-powered fleet above five and a half thousand. Meanwhile, China's Transportation Authority has announced plans for twenty thousand natural gas refuelling stations by 2020, up from 1 350 at end-2011. Although China does not benefit from low US gas prices, every diesel price hike makes transport gas, even based on oil-indexed gas, less uneconomical. The formidable size of the Chinese heavy truck fleet means that the deployment of transport gas could significantly reduce diesel demand once the necessary infrastructure is in place.

Power generation sector

The electricity sector accounted for roughly 7.5% of total oil product demand in 2010, down from 10% in 2000, a share that is expected to further drop through to around 6% by 2018. Using oil for power generation is often uneconomical. Oil is only really used to generate power on a significant scale where large subsidies are provided, typically in big oil producing economies, or as an emergency fuel, such as in post-tsunami Japan. Diesel oil is also increasingly used for back-up power generators in emerging or newly industrialised economies where grid electricity is insufficient or unreliable. Chronic blackouts and brownouts have led to increased imports of back-up generators, and increased associated demand for diesel fuel, in countries ranging from India and Pakistan to Nigeria and Venezuela. Diesel demand for such a purpose can be unpredictable, however, linked as it is to power outages.

Looking at the power sector as a whole, oil accounted for just over 4% of total power sector use in 2010, down dramatically from the near-7% level of 2000. While the shale gas revolution in North America has led to a dramatic increase in the role of natural gas in US power generation, this has been at the expense of coal rather than oil, as US electricity generators had already greatly reduced their oil use. The power sector only accounted for 2% of US oil demand in 2010, down from 4% in 2000. In contrast, oil still accounts for a large share of power generation in Middle East oil-producing countries. Saudi Arabia is a case in point. The Saudi power sector accounts for nearly half of that country's oil demand, a ratio that crept up in recent years (from 46% in 2000 to 47% in 2010). Crude oil dominates the mix, at just below two-thirds of total power-sector demand for oil in 2010, followed by gasoil and fuel oil. The Saudi government is seeking to curtail its use of oil in power generation and free up oil volumes for export, but any meaningful reduction is unlikely in the medium term as long as the Kingdom relies on the gradual introduction of efficiency standards and other such measures, which have a long lead time, rather than on price signals and subsidy reform, which are more effective on paper but politically charged.





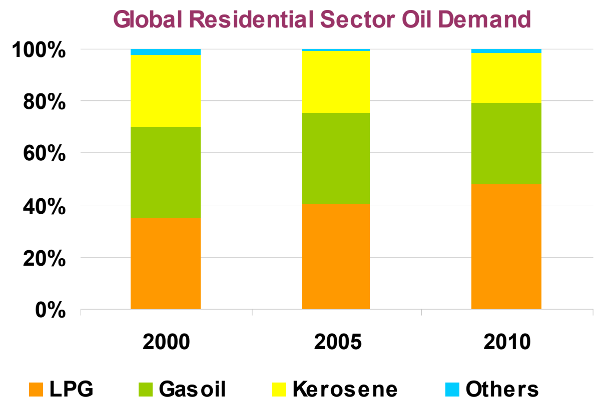
Other Middle Eastern countries have been showcasing pilot projects to shift power generation away from oil. For example, plans are under discussion in the UAE to build the country's first waste-to-energy plant. The proposed plan would receive roughly 1 million tonnes of municipal waste a year and convert it into sufficient electricity to power an estimated 20 000 households. Similar non-oil developments are anticipated across the global power sector, although the majority of the yet-to-be commissioned schemes would not come into fruition until after our medium-term horizon.

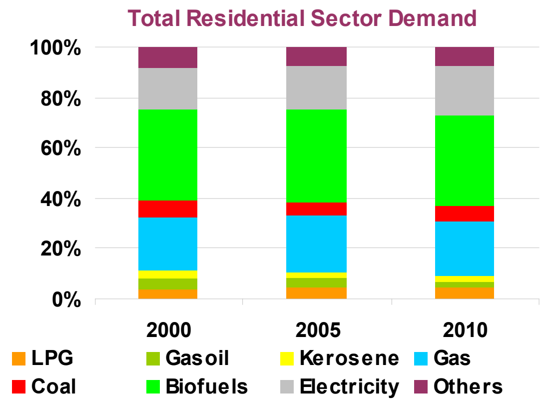
Residual fuel oil, crude and gasoil are the main oil-based boiler fuels used in power generation, with residual fuel oil accounting for roughly half of all power sector usage in 2010, followed by gasoil and crude. Other power sector oil fuels in 2010 included petroleum coke, refinery gas, LPG and kerosene. The importance of residual fuel oil as power sector fuel has waned in recent years, although the Great East Japan Earthquake in 2011 temporarily reversed the trend, as nuclear closures in Japan triggered a rebound in residual fuel oil use. This trend will likely remain relatively short-lived, however, and this *Report* expects residual fuel oil use in power generation to resume its downtrend over the forecast period.

Residential sector

Oil demand from the residential sector edged down to roughly 6% of total global oil demand in 2010 from 7% ten years earlier and is forecast to inch further down through to 2018, to around 5%. This *Report* projects that the residential sector will continue to see heightened efficiency gains suppressing oil demand, with the turnover cycle for residential equipment/appliances relatively short and subject to legislative measures to force greater efficiency. Gasoil dominates the OECD residential oil sector, accounting for roughly half of all oil demand in the residential sector in 2010. LPG dominates emerging market residential oil demand, at roughly two-thirds of demand in 2010, followed by kerosene (at 21.7%) and gasoil (11.6%). LPG demand notably forecast to grow in Africa (see *Africa, a new demand frontier?*).

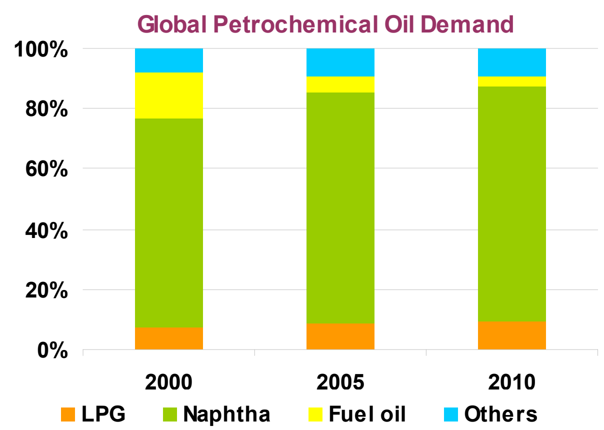
Oil products are forecast to account for a declining share of the residential sector through 2018. Natural gas and electricity will likely continue to displace oil in the residential sector. Legislative efforts have the ability to change the rapidity of this pace, as do relative market prices.

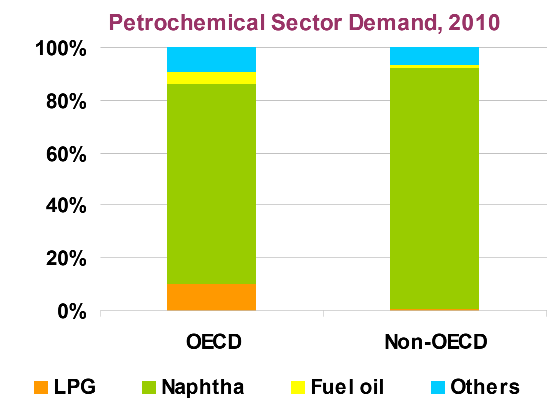




Petrochemical sector

Traditionally naphtha has dominated the global petrochemical industry, but in our outlook we are forecasting a degree of substitution over to LPG, particularly in North America. Naphtha accounted for roughly 78% of total global petrochemical sector oil demand in 2010, up from 70% in 2000, while LPG saw its market share inch up over the same period to 9%, from 7% previously. Both fuels gained market share at the expense of residual fuel oil, 4% of the market share in 2010, down from 15% in 2000. Through to 2018, LPG's market share is forecast to rise further on the back of low-priced and plentiful US supplies, which have spurred a revival of the North American petrochemical sector. The US, China and the Middle East dominate petrochemical demand through the forecast period, the later two supporting naphtha demand and the former LPG.

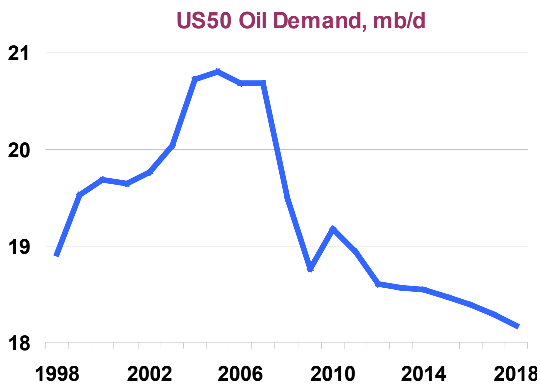


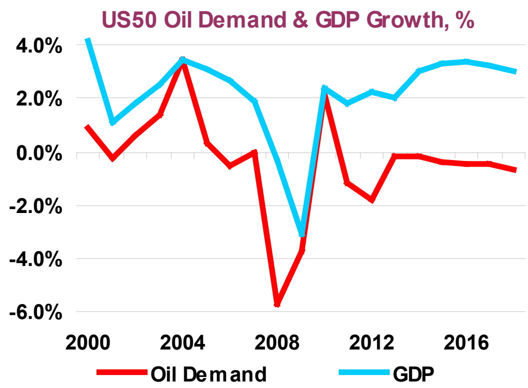


Top-10 consumers

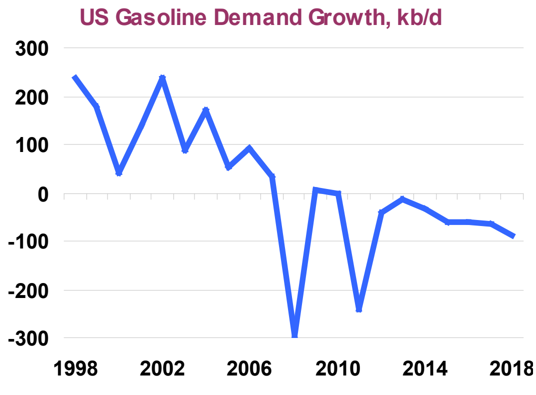
US

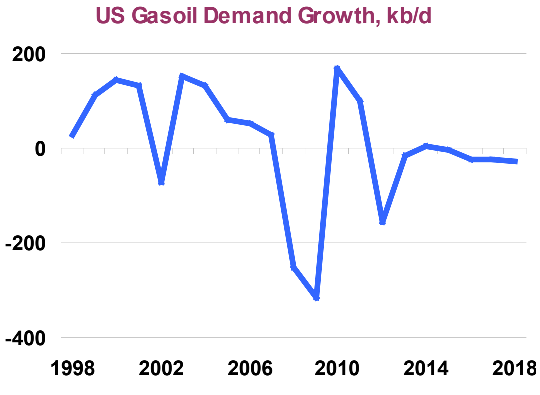
Having fallen by 2.2 mb/d since 2005, US oil consumption is expected to decline by an additional 0.4 mb/d (or 0.4% per annum) through 2018. US oil consumption is likely to be reduced by a combination of efficiency gains and product switching, with natural gas thought likely to be the chief medium-term substitute. Although the macroeconomic fundamentals that underpin US demand are forecast to strengthen, 2013 through 2018, oil consumption will largely fail to match this pace as the oil intensity in the US is forecast to decline by around 3.3% per annum. The predicted decline rate in the US oil intensity is marginally above its previous trend, 2.8% per annum 2006-12, reflecting increased vehicle efficiency. Continued low gas prices are also expected to provide additional switching opportunities at the margin, especially towards the end of the forecast period.





The sharpest decreases in US oil demand are expected in residual fuel oil, naphtha and gasoline, with respective per annum demand declines of -6.7%, -3.4% and -0.6%, 2012-18. Naphtha consumption is forecast to contract, as petrochemical producers increasingly switch to cheaper LPG, courtesy of the shale gas boom. Fuel oil is contracting as tighter government regulations trigger switching to cleaner gasoil and natural gas (non-bunker demand still accounting for nearly a quarter of total US fuel oil demand). Gasoline, which accounts for roughly half of all US demand, is projected to see continued demand contraction as the average efficiency of the US vehicle fleet increases, outweighing the boost in consumption that is likely to be provided by rising miles travelled. Additionally, the size of the total gasoline-burning vehicle fleet is thought likely to peak around 2015, hastening the pace of contraction after 2015.





US gasoil/diesel demand, although expected to hold up relatively better than gasoline, is still forecast to fall at an average per annum decline rate of 0.4% through the forecast period. The declining US gasoil forecast reflects continued fuel switching to natural gas in residential and commercial space heating, notably in the US Northeast, as well as the beginning of natural gas penetration in the rail and freight sectors.

At present, the greatest opportunity for fuel-switching to natural gas is in the US, where the shale gas boom has led to relatively cheap gas prices. Industry and domestic heating markets have already made great strides away from gasoil, but the US freight, courier, rail and bus sectors, all of which are leading diesel consumers, offer some of the next great opportunities to switch.

Top-10 Oil Consumers, thousand barrels per day

	2012	2013	2014	2015	2016	2017	2018
US50	18 606	18 578	18 539	18 473	18 388	18 300	18 182
China	9 597	9 976	10 360	10 787	11 190	11 578	11 959
Japan	4 729	4 560	4 477	4 453	4 433	4 410	4 355
India	3 652	3 737	3 860	3 985	4 114	4 243	4 364
Russia	3 318	3 436	3 552	3 665	3 775	3 882	3 987
Saudi Arabia	3 012	3 138	3 258	3 380	3 511	3 645	3 778
Brazil	3 005	3 103	3 183	3 266	3 334	3 388	3 435
Germany	2 338	2 301	2 288	2 277	2 266	2 254	2 239
Canada	2 293	2 300	2 293	2 277	2 258	2 239	2 220
Korea	2 268	2 268	2 268	2 267	2 267	2 267	2 263
% global demand	59%	59%	59%	59%	59%	59%	59%

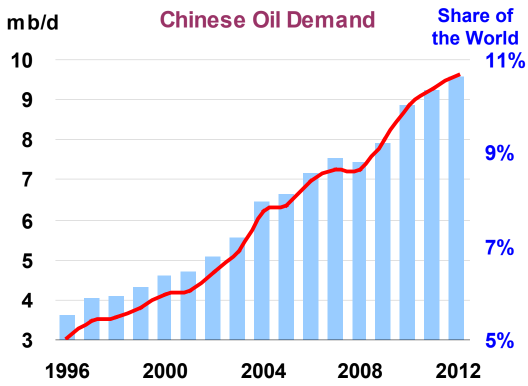
China

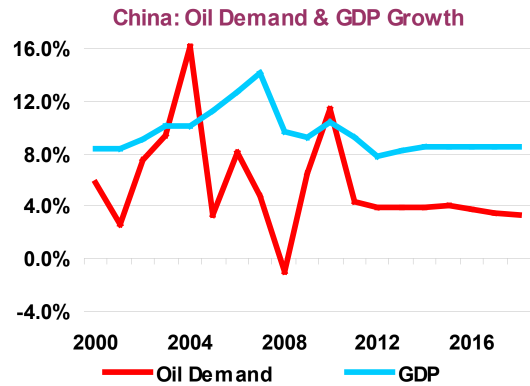
The importance of China to the global oil market has expanded exponentially in the past ten years. Spurred by increases in economic activity, China has become the leading driver of oil consumption growth. China accounted for roughly 40% of total global oil demand growth in 2012. Chinese oil consumption overtook Japan in 2003, but in the following eight years rose to more than double Japanese demand. This growth has steadily increased China's share of global oil demand. Chinese oil consumption estimated at around 9.6 mb/d in 2012 accounted for 10.7% of total global oil demand, up from 6.5% in 2002.

Chinese oil demand growth is expected to average a more subdued 3.7% per annum over the forecast period as the economy moves to a less energy-intensive stage of development. The Chinese share of total global oil demand growth is forecast to wane to roughly one third, 2012-18. Tepid demographic growth (with population growth seen close to flat by the end of the forecast period) will likely compound the effect of a maturing economy. Nevertheless, China's incremental oil consumption of 2.4 mb/d through 2018 will still make it the main driver of global demand growth.

Recent Chinese GDP figures showing 7.7% growth year-on-year in 1Q13 (versus consensus estimates of 8% growth) confirm the idea that China is past its takeoff stage and becoming a middle-income economy. Industrial output figures – generally considered a better predictor of oil demand – recently showed even more of a slowdown, easing to 8.9% growth in March, compared to consensus estimates of 10% expansion. Leading Chinese macroeconomic experts suggest that actual exports may have been below initially reported numbers. Thus, reported March export growth, which slowed to 10% on the year earlier from an average 23.6% in January-February, included a suspiciously large increase in exports to Hong Kong. Average 1Q13 export growth jumped by 74.2% to Hong Kong but slowed to just 6.8% to the US and inched up by a mere 1.1% to Europe. Many economists regard exports to the US and Europe as a more meaningful indicator of underlying Chinese economic activity.

The current 2017 forecast is 0.3 mb/d higher than our October outlook, reflecting the higher underlying macroeconomic outlook. Chinese economic growth is now expected to rise through to around 8.5% by 2018, whereas the previous estimate was closer to 8.1%.





As the Chinese population is expected to become progressively more prosperous each year through to 2018, household demand for motorised transportation will inevitably increase, which will lend substantial support to Chinese gasoline demand and, to a lesser extent, gasoil/diesel demand. The car ownership rate is forecast to rise to around one hundred vehicles per thousand inhabitants by 2015 and to around 140 vehicles per thousand people by 2018, an exceptionally rapid expansion. More efficient car choices will be made, but as recently revealed in a detailed study by consultant McKinsey large vehicle sales will continue to outpace smaller choices through 2020. Prestige remains an important motivation in many car purchase decisions, particularly for new rapidly expanding markets, a factor that certainly adds to the bullish tone of the Chinese gasoline demand forecast.

Chinese demand growth is forecast to ease towards the tail end of our forecast period, as the economy increasingly moves towards less oil-intensive industries and the government makes a concerted effort to reduce China’s oil import-dependence. Chinese oil demand growth is forecast to ease to around 3% towards the end of the forecast, with the main growth-contributing fuel – gasoline – possibly losing market share to alternative fuelled vehicles.

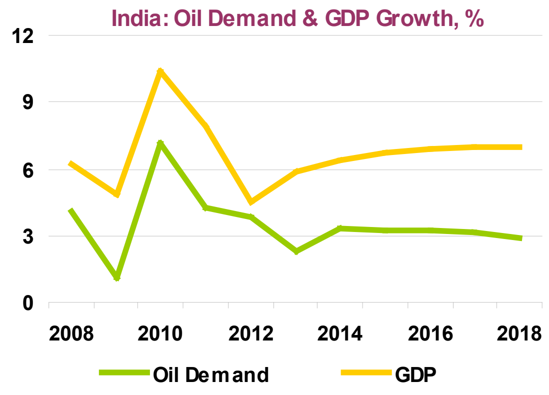
Japan

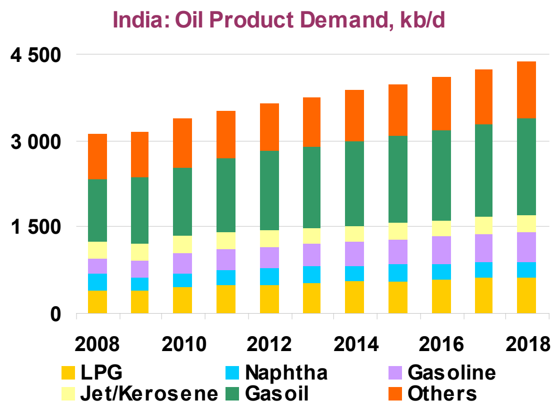
After a period of unusually strong oil demand growth, Japan is forecast to return to a declining trend in 2013-18. A devastating earthquake and tsunami hit the country in March 2011, taking out the Fukushima power plant and eventually leading Japan to idle most of its nuclear capacity. This resulted in a major, one-off increase in demand for LNG and oil as replacement fuels in power generation. Demand for residual fuel oil and ‘other products’ (including crude for direct burn) increased by 28% and 21.6%, respectively, in 2012.

A particularly pronounced decline is foreseen in the Japanese oil demand forecast, of around 1.4% per annum, 2012-18, as nuclear power generation capacity is expected gradually to come back online. The timing of this decline remains unclear, however. Since taking office in December 2012, the government of Prime Minister Shinzo Abe has rescinded an earlier policy adopted after the great East Japan Earthquake and Tsunami to phase out nuclear power generation. Further downside risks to Japanese oil demand originate from the weak transport sector forecast, with gasoline demand expected to decline by around 1% per annum, reflecting in part the increasing efficiency of the vehicle stock. The average efficiency of the Japanese vehicle stock is forecast to rise by around 3% per annum, 2010-15, and 2% thereafter, more than offsetting an expected expansion in the vehicle fleet and average distance travelled per vehicle.

India

The economic slowdown of 2012 has caused Indian oil consumption to stall, with reduced growth seen across most of the main product categories, bar gasoil which staged a counter-trend rally, garnering support as below-year earlier monsoon rains in 2012 required additional usage in agriculture (diesel-powered water pumps). A further deceleration in Indian demand growth is foreseen in 2013, as the government's gasoil subsidy cuts inevitably dampen consumption. Bulk industrial diesel subsidies were removed in January 2013, with a series of monthly retail subsidy cuts also being implemented.



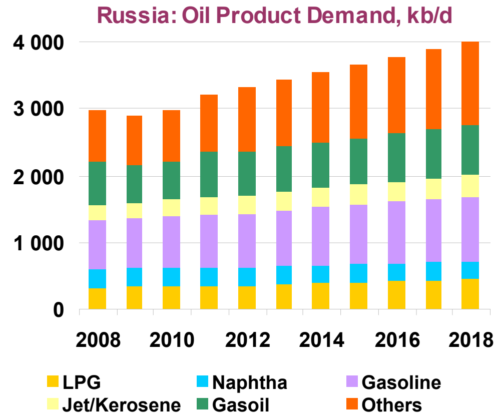


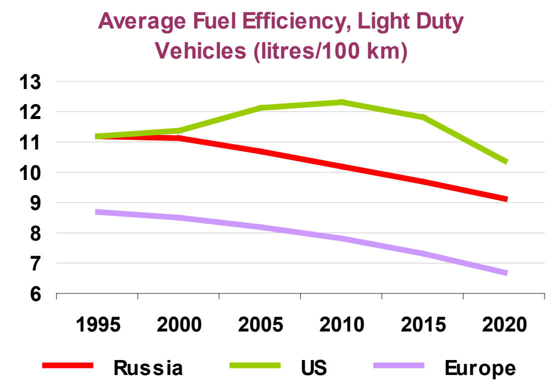
Demand growth is forecast to accelerate once again in 2014, bolstered by a robust macroeconomic expansion, before settling back to around 3% per annum growth through the reminder of the forecast period. A combination of efficiency gains, infrastructure constraints and the service-oriented nature of the Indian economy combine to restrain India's growth profile.

Russia

The strength of Russian oil demand growth has been one of the surprises of recent years, as consumption growth averaged around 5% per annum in the three years, 2010-12, supported by particularly sharp upticks in gasoil and jet/kerosene. Relatively robust demand growth is forecast to continue through to 2018, albeit at a gentler pace as some modest efficiency gains are assumed. For example, the average efficiency of the Russian car pool is forecast to increase by around 1% per annum, 2010-2015, accelerating to 1.3%, 2015-20.

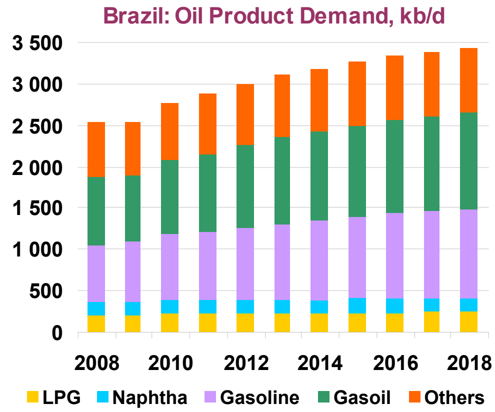
Russian demand growth is forecast to average just over 3% per annum, 2012-18, with momentum gradually easing through the post-2014 forecast. Developments in the relatively inefficient Russian car pool (30% less efficient than OECD Europe in 2010) will provide the majority of the easing momentum, coupled with estimates of average-distances travelled per vehicle peaking in 2015.

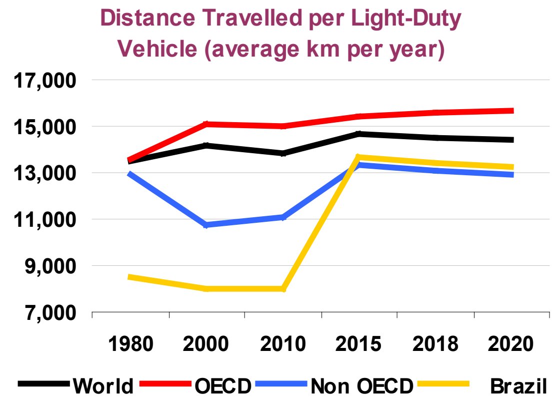




Brazil

Brazilian oil demand has risen at a rapid clip since 2009, with an average expansion just shy of 6% in the three years up to and including 2012. Consumption growth, however, looks set to ease over the next couple of years, as economic growth slows on the back of a weaker commodities sector. Brazil is also continuing moves to diversify energy supplies away from oil and accelerating efficiency gains. Notably above-trend rises are foreseen in the transportation fuel markets, as rapid projections of Brazilian income growth outweigh likely efficiency gains.





Forecasts of a reduction in the average distance travelled per vehicle, post-2015, will noticeably slow the progress of Brazilian transport fuel demand in the latter stages of our forecast. This factor, coupled with predictions of slower growth in the vehicle stock, will combine to ease the progress of transportation fuel demand.

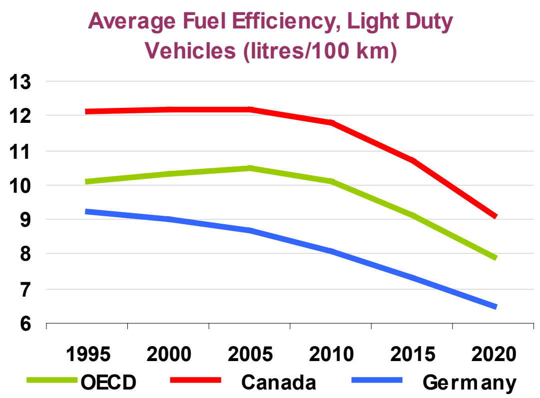
Saudi Arabia

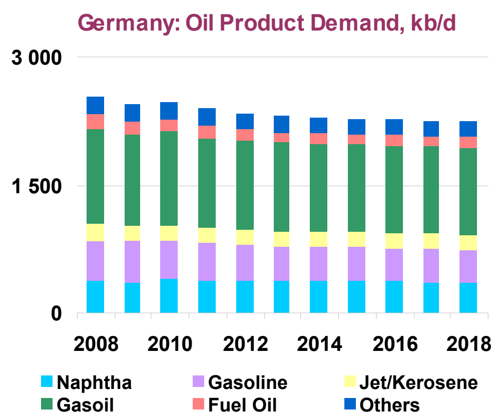
Relatively strong demand growth is forecast in Saudi Arabia through to 2018, supported by the rapidly expanding population base and a continuing high level of urbanisation, albeit down notably from its previous high. The IMF's population statistics have the number of inhabitants rising by around 5 million, or 15%, between 2011 and 2018. Generous oil price subsidies are expected to compound the effect of this near-2% annual growth rate, lifting demand growth to an average 3.9% annually. A high urbanisation rate tends to correlate with robust oil demand growth, as it links people with the infrastructure to consume oil, such as roads, runways, factories, air-conditioning and power supplies. The growth outlook has, however, been dimmed to around two-thirds of its previous height – 3.9%, 2012-18, versus 6.1%, 2006-12 – as additional efficiency gains are assumed.

Having risen very strongly in the three-year period 2009-11, growth in Saudi Arabian ‘other product’ demand will likely slow through 2018. The reasoning behind this shift is that the robust gains of 2009-11 were largely due to additional oil products being used in the heavily subsidised Saudi power sector. But Saudi Arabia is implementing policies designed to boost efficiency in electricity use and to encourage alternative forms of power generation, specifically gas-fired generation and renewable energy. HSBC estimates that USD 35 billion a year is being spent on subsidising the electricity and desalination industries. In an effort to reduce the expense, the government has launched a public awareness campaign (Tarsheed), with the aim of encouraging rational use of power in the commercial and residential sectors. Several solar energy programmes are in the development stage, with USD 109 billion worth of capital spending planned over the next two decades to build 41 000 megawatts of solar capacity, the aim being to supply 30% of the country’s total energy needs by 2030. In the shorter term, gas will play a bigger role, with rapid production growth at the Karan gas field, up 400 mcf per day in the summer of 2011 through to 1.8 billion by April 2013, reportedly targeted for the power sector.

Germany

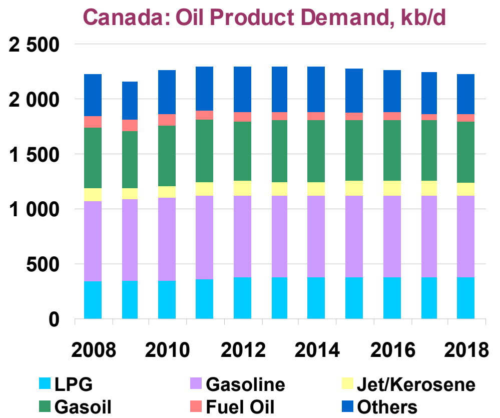
A period of weak macroeconomic growth has forced German oil demand into a sharp contraction, falling by 2.6% in 2012. Further declines are forecast through to 2018, albeit at a slower pace of 0.7% per annum, as the underlying economic backdrop is forecast to improve at a very slow rate. The declines are driven by expected efficiency gains in the vehicle fleet.

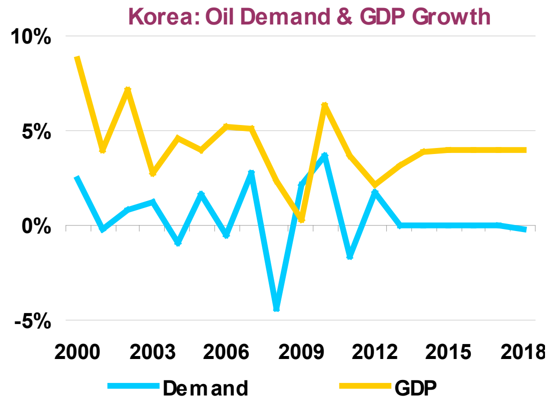




Canada

Following several years of strong growth, Canadian oil demand is expected to decline over the forecast period. After an expected 10 kb/d, 0.3%, uptick in 2013, oil demand is expected to fall by 80 kb/d, or 0.7% per annum, through the rest of the forecast period. This is a break from recent years when, on the back of strong performance from its oil sector, economic growth in Canada bolstered oil demand, which averaged around 2% per annum (2010-12). Lower use of transportation fuels is driving the expected declines. The Canadian car pool is historically much less efficient than the OECD-norm, providing opportunities for efficiency gains, which when coupled with expectations for average miles travelled peaking in 2015, curtail the overall demand forecast.





Korea

In the forecast, South Korean demand should continue to follow its recent near-flat trajectory, although some product categories will outperform overall growth. LPG demand, for example, is forecast to outpace naphtha, post-2013, as the Korean petrochemical industry is thought likely to express a preference for LPG. Two big Korean petrochemical producers, Honam and YNCC, recently reported that they had increased LPG feedstocks, from 5% to 10%, in their crackers for 2013. Gasoline demand declines, by around 0.8% per annum through the forecast, as the vehicle fleet becomes progressively more efficient whilst average miles travelled peak around 2015.

Africa: a new demand frontier?

A dearth of reliable energy statistics has long clouded African oil demand patterns in uncertainty. Due to the low base of African oil demand, regional data gaps have not generally been a prime focus of oil analysis. As of 2000, the continent accounted for roughly 3% of total global oil product demand. Yet its relative wealth has risen in recent years, fuelled in part by the sharp escalation in industrial commodity prices and China's emergence as a fast-growing importer from the region, and anecdotal evidence increasingly suggests that African oil demand growth has been significantly underestimated. The rapid spread of cellular phone access in the region has also been a powerful economic enabler as well as a direct source of energy demand at the margin, to power cellular telephone towers. Notwithstanding the continent's persistent governance and security challenges, there are strong reasons to believe that African oil demand growth will accelerate further over the forecast period.

Much of the recent historical data on African oil demand have become increasingly inconsistent with the region's strengthening macroeconomics. The latest annual data, for 2010, which were revised upwards, are a case in point. Previous estimates of African oil demand for that year reported it down year-on-year despite GDP growth approaching 5%. For South Africa, one of the continent's largest economies, 2010 data indicating steep demand contraction were particularly dubious, in view of both intelligence from market participants to the contrary and the country's economic performance that year.

Africa: a new demand frontier? (continued)

South African Oil Demand & Economic Growth

	2009	2010	2011	2012	2013	2018
GDP (% change)	-1.5	3.1	3.5	2.3	2.8	3.5
Oil demand (kb/d)	597	606	623	633	657	780
demand growth, per annum (kb/d)	-15	9	17	10	24	23
change over October 2012 MTOM	0	128	72	62	64	

Sources: IEA; IMF

South Africa's data problems could in part be traced to a data break associated with legal changes which caused the main aggregator of oil statistics, the South African Petroleum Industry Association (SAPIA), to cease collecting the figures. Estimates by the IEA Secretariat temporarily filled the void. Based on macroeconomic evidence, the country should have seen more oil consumed in 2010 than 2009. South Africa hosted the football World Cup in mid-2010, which should have been a net-positive contributor to demand, bringing with it additional tourists who take planes, buses, hire cars, consume electricity, etc. Gasoil/diesel demand, in particular, should have seen a rising trend in 2010, not the steep contraction reported in official data. Upward adjustments of about 130 kb/d have been applied to the 2010 estimate and now point to mildly rising demand. Gasoline and gasoil account for the bulk of the revisions, 50 kb/d and 45 kb/d, respectively. Given South Africa's comparatively large footprint in the region, these revisions alone significantly raise the estimate of aggregate demand for Africa as a whole.

South African Product Breakdown, kb/d

	2009	2010		2011		2012	
		new	old	new	old	new	old
LPG	10	10	7	10	11	10	12
Naphtha	2	2	1	2	1	2	2
Motor Gasoline	208	210	160	213	180	214	185
Jet & Kerosene	52	52	48	52	48	52	49
Gasoil/Diesel	176	183	137	191	165	198	173
Residual Fuel	55	55	53	55	52	52	54
Other Products	93	93	70	100	93	104	96
Total Products	**597**	**606**	**477**	**623**	**551**	**633**	**570**

Closer examination of the data for another large African economy, Nigeria, reveal a similar disconnect in the 2010 series that cannot simply be explained away by extraneous factors. Historical Nigerian oil demand data come from the state oil company, Nigerian National Petroleum Corporation (NNPC), and tend to miss privately imported product flows. Traditionally Nigeria publishes relatively good statistics on production and trade, but the quality of this data is tarnished due to those products not officially accounted for due to illegal trade, smuggling or pilferage. Reassessing the 2010 series in more detail, it is apparent that both of the two key domestic transport fuels – gasoil/diesel and gasoline – were being underestimated in 2010.

Nigerian Oil Demand & Economic Growth

	2009	2010	2011	2012	2013	2018
GDP (% change)	7.0	8.0	7.4	6.3	7.2	6.7
Oil demand (kb/d)	279	296	311	326	346	416
demand growth, per annum (kb/d)	15	17	15	15	20	12
change over October 2012 MTOMR	32	57	6	18	35	

Sources: IEA; IMF

Africa: a new demand frontier? (continued)

Following the global economic slowdown of 2008-09, macroeconomists reported a steep rebound in Nigerian economic momentum in 2010. The IMF, for example, claims Nigerian GDP climbed 8% in 2010, its most rapid expansion since 2004. Previous annual estimates of Nigerian oil demand saw an absolute decline in Nigerian consumption in 2010. Most problematically, that estimate encompassed double-digit percentage point declines in both gasoline and gasoil/diesel demand. Revised data now show a rising consumption trend in 2010, with an absolute gain in gasoline demand and only a modest contraction in gasoil/diesel. These revised 2010 data are more consistent than the previous ones with reports of relatively robust gasoline and gasoil imports at the time.

Overall, these revisions to the historical African oil demand series provide a more realistic African consumption estimate of 3.5 mb/d in 2010, equivalent to a gain of 90 kb/d (or 2.6%) year-on-year. Not only is this estimate, which is based upon a combination of GDP and market intelligence, more in keeping with the relatively robust macroeconomic growth experienced in the region, but it is also consistent with evidence privately obtained from traders, refiners and other market participants on the ground.

Strenuous efforts have been made to improve the state of energy statistics in the region. For starters, the IEA has been actively working with the African Energy Commission (AFREC): helping to design annual energy questionnaires; and setting up training workshops. AFREC published its first annual *Africa Energy Statistics* publication in December 2012.

Africa is forecast to provide one of the fastest paces of global oil demand growth in the medium term, rising by an average of 4% per annum, 2012-2018. The robust forecast underpinned by particularly strong gains in the transport sector, gasoline up 4.5% per annum, 2012-18, gasoil 4.5% and jet/kerosene 3.9%. Demand for gasoil for power generation is also on the rise, as industrial facilities and other consumers increasingly rely on back-up diesel-fired generators to make up for the failings of a notoriously unreliable grid, as an insurance against daily blackouts. Nigeria thus has reportedly become the world’s top importer of back-up generators, the size of which range from that of a barge to a table-top unit. A Coca-Cola plant near Lagos thus reportedly relies upon a privately-owned floating power plant, mounted on a barge anchored in Lagos port, for its electricity.

LPG, a typical transition fuel for emerging economies, is also undergoing significant demand growth in Africa. Several market participants have been building, and investing in, new terminals and import infrastructure to support fast-growing trade in that fuel. LPG is a relatively easy-to-distribute fuel and an easy way for households in expanding economies to gain access to modern energy services, displacing traditional biomass such as wood or cow dung, which are time-consuming to gather and extract a heavy health toll on consumers through particulates and other emissions. In Asian economies, LPG has often served as an intermediary between traditional biomass and city gas. Rising African demand for LPG could provide a much needed market for surging US output in the wake of the shale revolution.

Severe hurdles continue to stand in the way of a real takeoff in African oil demand, including a lack of road infrastructure, security challenges, and corruption as well as other governance issues. But the very low historical base of African demand and the region’s rapid income gain mean that great leaps in demand growth may be in the cards – just when the prospect of excess global gasoline and naphtha production in the next few years (due to steep growth in global refining capacity and board shifts in feedstock quality and demand patterns) could set the stage for an abundance of light ends looking for new market outlets. This makes the early efforts to improve the quality of African oil data all the more pressing.

SUPPLY

- **Global supply capacity is expected to increase by 8.4 mb/d to 103 mb/d in 2018**, or 1.4 mb/d per year. Almost 20% of liquids growth comes from Iraqi capacity, and 40% comes from North American oil sands and light, tight oil (LTO) production.

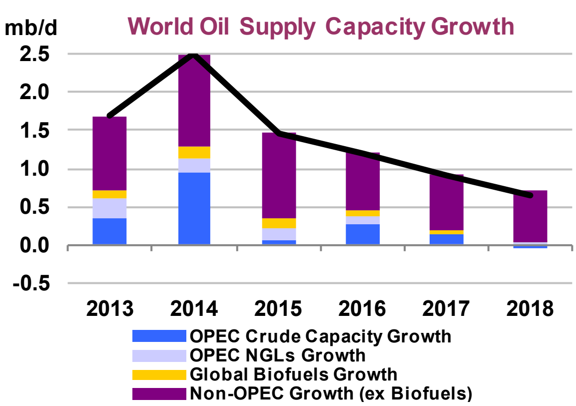
- **NGL supply grows by 2.0 mb/d from 12.9 mb/d in 2012 to 14.9 mb/d in 2018**, with two thirds in non-OPEC countries. OPEC NGLs and non-conventional supplies increase to 7.0 mb/d in 2018, a gain of 0.7 mb/d from 2012 levels. Saudi Arabia and the UAE are major contributors to growth.

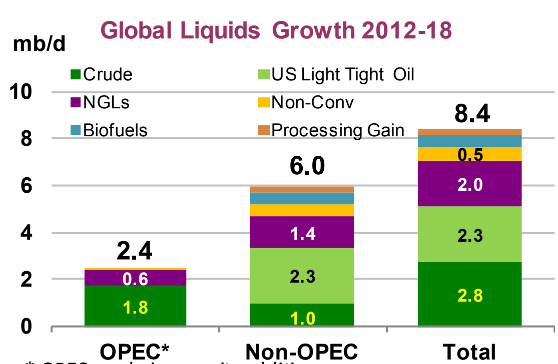
- **OPEC crude oil capacity is forecast to rise by 1.75 mb/d over the 2012-18 period**, to 36.75 mb/d. Higher output from Iraq more than offsets a steep decline in Iran. Capacity estimates are around 750 kb/d below our previous 2011-17 forecast, with African member countries accounting for the bulk of the downward revision.

- **Non-OPEC oil supply is expected to grow by 6 mb/d from 2012 to 59.3 mb/d in 2018**, or at an annual average of 990 kb/d (1.9%). Approximately 65% of the growth comes from North American LTO and Canadian oil sands production and offsets mature field decline elsewhere. US tight oil is forecast to grow by 2.3 mb/d by 2018, raising US crude output to 8.4 mb/d.

- **World biofuel production is expected to reach 2.36 mb/d in 2018**, an increase of 503 kb/d 2012-2018. Short-term downward revisions in the US, Argentina and OECD Europe, as well as increasing uncertainty over political support, affect the medium-term outlook and lead to a 28 kb/d downward adjustment in 2017, compared to the October 2012 forecast.

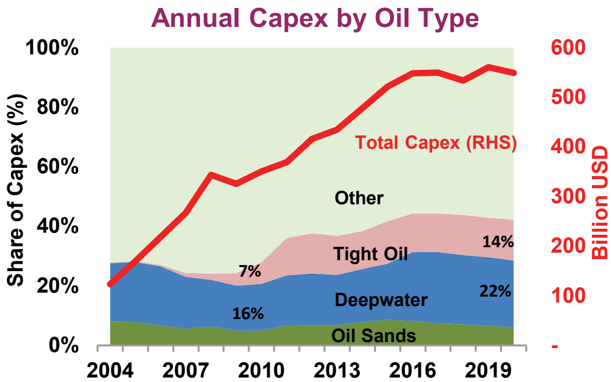
- **High oil prices increased capital spending by over 8% in 2012, but high prices have also led to increased demand for labour and oilfield service equipment.** Global finding and development costs and US cost inflation were slightly higher on average in 2012 than in 2011. Markedly lower prices would reduce drilling activity, demand for oilfield services, and production rates in the medium term.





* OPEC crude is capacity additions
Global Refinery processing *gains included in Non-OPEC*

Trends in global supply



Source: IEA Analysis of Rystad Energy. Oil deposits only.

Capex shifts to non-OPEC and tight oil in the medium term. From 2006 to 2012, OPEC capex grew by about 50% in contrast to 90% in non-OPEC countries. From 2012 to 2018, non-OPEC capex grows by 20% while OPEC capex grows 30%, but OPEC's average share of global capex drops to below 22% from 24% previously. Our forecast shows that OPEC capacity is expected to increase by 1.75 mb/d by 2018 whereas non-OPEC production is slated to rise by 6 mb/d. Better contract terms in some non-OPEC countries than in OPEC member countries and above-ground issues constrain investment flows in the medium term. According to Rystad Energy, global capital expenditures on oil deposits are expected to grow to around USD 525 billion from around USD 400 billion currently. The distribution of capex by type of projects changes dramatically. The light, tight oil (LTO) share of capex doubles to around 14% by 2018 from 7% currently. Deepwater capex increases its share to 20% by 2018 from around 16%. Enhanced oil recovery projects and oil sands developments also claim a larger share of capex.

High oil prices are enabling companies to employ technologies from the US tight oil boom, such as hydraulic fracturing and horizontal drilling, in conventional reservoirs. At current prices, companies can afford to drill more wells, extract more from existing wells, and use improved oil recovery or enhanced oil recovery to mitigate the overall impact of natural field declines. Fracturing, horizontal drilling and improved reservoir characterisation, fixtures of the US tight oil renaissance, are bound to be employed elsewhere in low permeability conventional reservoirs, especially in places where it is in the country's best interest to reduce import dependency: China and India and other OECD countries. Sustained high oil prices are improving the economics of deepwater projects, which have high capital expenditures. Areas that stand to benefit include the Middle East, the US Gulf of Mexico, East and West Africa, and Asia. Companies have also announced a host of new projects in the last six months especially in the North Sea and Russia that capitalise on existing production and transport infrastructure.

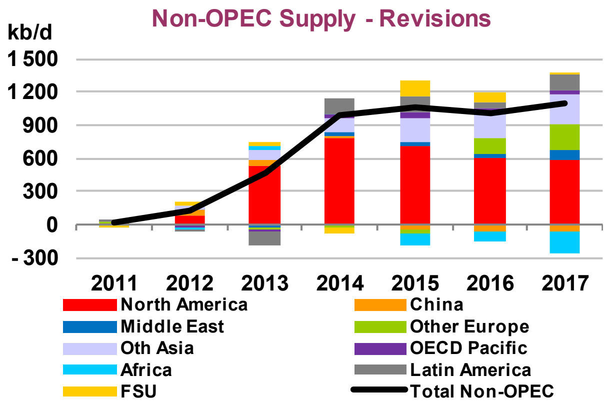
Expect delays at mega-projects. As capex shifts strongly towards enhanced oil recovery, LTO, oil sands expansions, and tiebacks to existing infrastructure in the North Sea, we expect delays from projects that require starting from scratch, or greenfield, especially mega-projects with price tags of over USD 10 billion. Companies have flexibility in their project pipeline and have the ability to reallocate investment, delay final investment decisions (FID), or delay the online date until costs are lower or market conditions are better. Mega projects onshore East Africa, and deepwater projects in the Gulf of Mexico, Brazil and West Africa are likely to see further delays in the medium term.

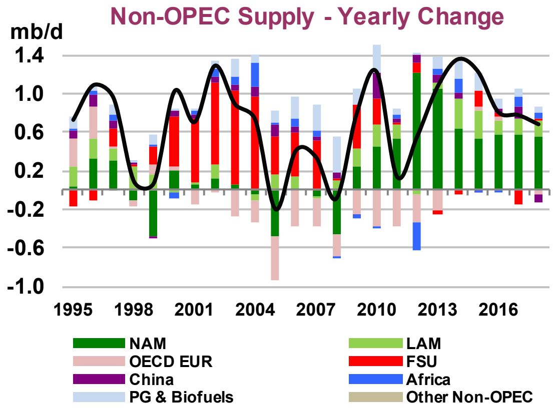
Tight oil outside the US. In the medium term and in contrast to the US, production growth from continuous or unconventional reservoirs are expected to take off slowly. The US's business environment, which facilitated independents taking exploration risk, is unique from most other places where promising resources have been found. In China, Russia and Argentina state owned entities dominate the oil production landscape. Acquiring drilling services will also be challenging, so governments will need to provide adequate incentives.

Non-OPEC Supply

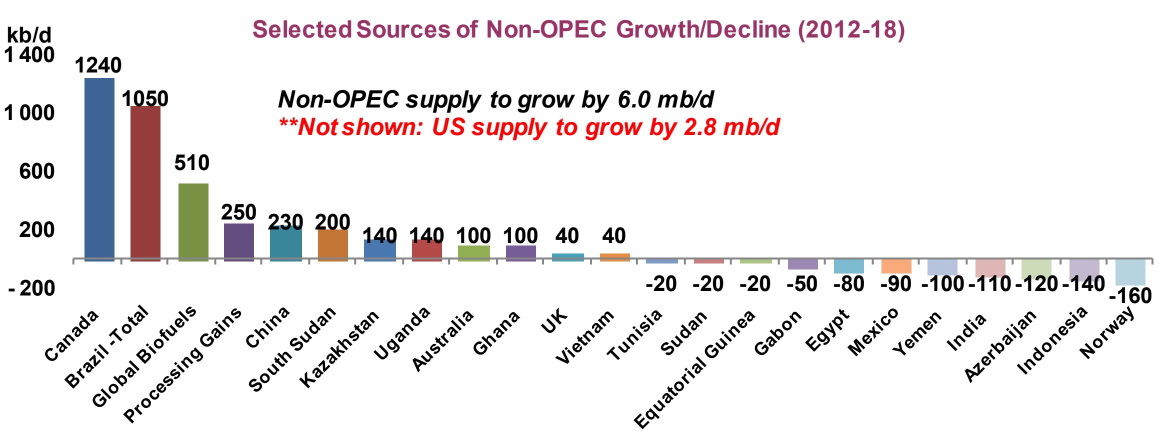
- **Non-OPEC supplies are expected to increase by 6 mb/d from 53.3 mb/d in 2012 to 59.3 mb/d by 2018.**
- **US tight oil is forecast to grow by 2.3 mb/d by 2018, raising US crude output to 8.4 mb/d.**
- **Annual non-OPEC supply growth averages 990 kb/d (1.9%) from 2012 to 2018.**

Output growth from North America dominates the medium-term growth profile, in sharp contrast to the FSU, which dominated over the last decade. Unplanned outages, which reached up to 1.2 mb/d over the last year kept production growth under 600 kb/d, but the gradual return of some of this production in the last few months, especially in the North Sea and Sudan, will raise non-OPEC output by 1.1 mb/d in 2013. Growth rates are expected to remain very high by historical standards in 2014 and 2015, at 1.4 mb/d and 1.2 mb/d, respectively, as new tight and unconventional North American supplies come online.





Fracturing, horizontal drilling and improved reservoir characterisation, fixtures of the US tight oil renaissance, are bound to be employed elsewhere in low permeability conventional reservoirs, especially in places where it is in the country's best interest to reduce import dependency, such as China, India, and other OECD countries, or to maximize exports, such as in Russia. But these incremental volumes stay under the radar of forecasters as these are not stand-alone projects. Where small and medium-sized enterprises are active, they can bear the initial risk of these development projects.



Offsetting this positive production trend are new local content policies in Brazil, Kazakhstan, and Eastern Africa. Where recently found resource wealth might benefit the local economy, countries are increasingly employing various local content policies (see '*Colombian Output in the Medium Term Dependent on Security, Transport, Technology*'). Major companies have a portfolio of assets to manage and will reshuffle capex to places that offer the best returns on investment.

Revisions

Discounting a small downwards revision to our 2011 baseline estimate, non-OPEC supplies are adjusted upwards by 780 kb/d through the forecast period since the 2012 *MTOMR*, led by upwards revisions of 560 kb/d in the OECD. Since the 2009 *MTOMR*, our forecasts for non-OPEC supply growth have been consistently revised upwards. This year is no exception. These revisions largely reflect the impact of persistently high oil prices. Average Brent prices have hovered around record nominal highs in 2011 (USD 111/bbl) and 2012 (USD 112), exceeding the prior yearly average peak in 2008 (USD 97/bbl). Those sustained high prices have facilitated the broader application of new technology and are bringing new supplies to the market more quickly and at higher rates than previously anticipated.

Upwards revisions in the OECD, but megaprojects to suffer at the expense of LTO. The large influx of capital expenditures in US hydraulic fracturing and horizontal drilling raises the US liquids forecast by 420 kb/d on average since October 2012. Other notable revisions include a 260 kb/d increase in North Sea output in the 2016-17 timeframe due to a host of new projects, increased drilling activity, and better recovery technologies that have enabled operators to extend the life of their fields. More clarity on the tax structure, especially in the UK, has also helped matters. On the flip side, increasing capex levels in the OECD could dent the pace of growth in investment from non-OPEC Africa production. Though the players are somewhat different and they tap into different sources of capital, major oil companies may begin to focus their activity where investment requirements are not as steep.

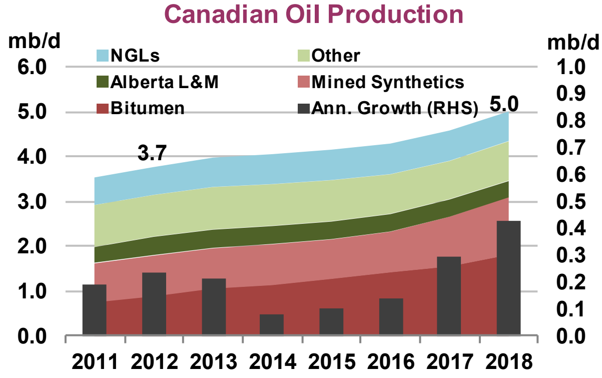
OECD Americas

Canada

Canadian oil sands production is expected to lift liquids output by 1.3 mb/d from 3.7 mb/d to 5.0 mb/d in 2018. Canadian oil sands accounted for half of Canadian liquids production in 2012. Production growth is expected to be limited to 100 kb/d in 2014 and 2015 due to pipeline constraints, but growth rates should subsequently pick up. Though the forecast output in 2017 remains the same as expected in October's *MTOMR,* at 4.6 mb/d, project slippage has reduced output in other years by 90 kb/d in 2013-16 compared to October.

- **Oil sands output to grow by 1.3 mb/d by 2018.** For oil sands production in particular, production growth is centred largely in the *in situ* production of bitumen, though mined bitumen production from the first and second phases of Imperial's Kearl project, as well as Suncor's Fort Hills, is also a component. The economics of upgrading mined bitumen for production of light synthetic crude oil are challenged in light of the large volumes of

Canadian Oil Production



incremental output occurring in the US. Suncor and Total announced that they would not proceed with the Voyageur upgrader project that would have upgraded bitumen from the Joslyn mine.

Canadian Oil Sands Supply Cost Comparison
(WTI Equivalent, USD/bbl)

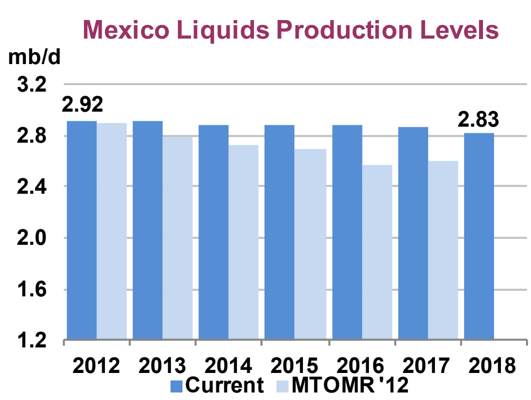
	CERI	ERCB	NEB
SAGD	64.62	47-57	50-60
Integrated Mining & Upgrading	91.07	88-102	85-95
Stand-alone Mine	81.51	61-81	65-75

- The discount of Western Canadian Select (WCS) crude to WTI ranged between -8.50 USD/bbl and -24.50 USD/bbl in 2012 but increased to -35 USD/bbl in January and -25 USD/bbl average YTD in 2013. Although some analysts forecast that the differential will not impact existing production volumes, this *Report* reckons that incremental volumes are likely to be delayed if the discount persists. Whether or not the trans-border portion of the Keystone XL pipeline is approved will affect this discount and clearly the impetus for government action is there as the discount of Western Canadian Select (WCS) to other oil benchmarks reduces Alberta and Canadian government revenues. Higher-cost rail transport is an alternative option but would likely eat into producer margins, and thus might slow projects (see *Trade section 'Railing Crude in North America'*).

- In the medium term, expected oil sands project volumes exceed existing pipeline capacity. Therefore, the Canadian government and its provinces are seeking alternative transport solutions by reversing unused natural gas pipelines and by exploring the viability of exports to Asia via an expanded Transmountain pipeline or a new Northern Gateway pipeline.

- Canadian tight oil could surprise to the upside. Production growth in the tight oil basins of the Exshaw (extension of the Bakken formation), the Duvernay, Montney, and Cardium has raised Canadian tight oil output to around 300 kb/d at the end of 2012. Production in the Cardium posted the most drastic increase in 4Q12, up 24% year-on-year to around 80 kb/d. But data is likely to show a slowdown in the first couple months of 2013 due to cold weather and heavy snowpack. In the medium term, rig availability is likely to constrain growth, given the particular specifications needed for rigs to operate in such harsh weather conditions.

Mexico



Mexican production has been revised upward from the last outlook due to recently announced plans to increase production from new fields and further maintain production at legacy fields. With the election of a new President, policy change could impact the direction of Mexico's forecast in the medium and long term. President Enrique Peña Nieto has promised broader energy reform, which the Mexican Congress is expected to debate in 2H13. The President is also spurring efforts to reform the national oil company, Petroleos Mexicanos (PEMEX), and reportedly promised that PEMEX would not "be sold, nor will it be privatised," but that it would be "modernised and transformed." The president's political party, the Partido Revolucionario Institucional (PRI), and the opposition have yet to agree on the direction of overall energy reform, however, and the new administration may face tough opposition in enhancing private participation in oil and gas production.

In the meantime, the Ministry of Energy recently issued a report expecting that production will total around 3 mb/d in 2018, compared to 2.8 mb/d in our most recent forecast. The forecast for Mexico is based on several assumptions:

- **Reduced decline rates.** Ku-Maloob-Zaap and Cantarell are expected to decline by 4% and 8% per year, respectively. PEMEX is also planning enhanced oil recovery (EOR) at several fields in the medium term, including Crudo Ligero Marino, Antonio Bermudeez, Ixtal-Caan-Chuc, Bellota-Chinchorro, Ogarrio-Magallanes, Jujo-Tecominoacán and Delta del Grijalva.

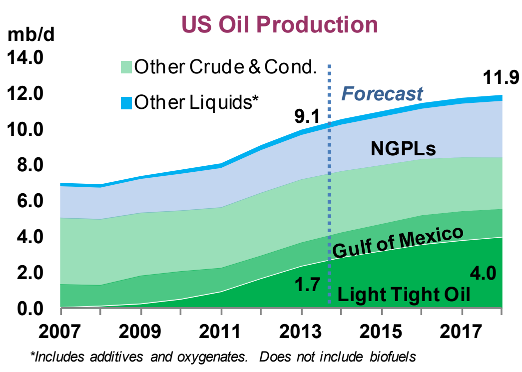
- **Fields under development.** Fields in the development phase include Ayatsil, Xux, and Kambesah, which should increase output to 100 kb/d from 20 kb/d currently. The ATG or Chicontepec project, which is producing 75 kb/d currently, is also poised to grow to over 150 kb/d in the medium term. Pemex recently invited tenders for six contracts to develop blocks here under service contracts that provide cash incentives for production.

- **Fields under exploration.** Some projects in the exploration phase are expected to add to output after 2016 including Campeche Oriente, Chalabil, Uchukil, Comalcalco, and Cuichapa.

The government understands that its efforts to maintain output at current levels of 3 mb/d must come hand-in-hand with an improvement in PEMEX's own ability to invest and attract foreign investment. PEMEX is the only major oil company worldwide which reported a negative net income, mainly due to its large tax burden. Broadening the Mexican tax base and reducing the tax burden on PEMEX would allow it to invest more into its actual business, that of developing Mexico's resource potential. But any change to the system will have to be balanced against the impact on government revenues and job creation. The ruling PRI voted in March to modify its internal statutes and allow congressional legislators to vote on initiatives allowing greater private investment in the oil sector, as well as taxes on food and medicines. This represented a stunning reversal of the party's long-standing position. Still, other parties remain staunchly opposed to further reform of PEMEX, which means that the production outlook remains highly uncertain in the medium term.

United States

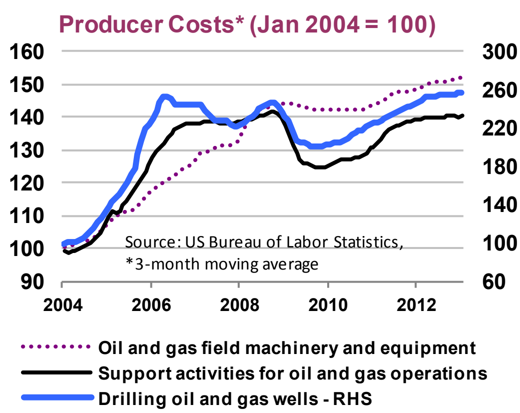
After growing by 1 mb/d in 2012, an all-time record for a non-OPEC producer, US oil output stands to expand by a further 2.8 mb/d to 11.9 mb/d in 2018, from 9.1 mb/d in 2012. Tight oil production is expected to grow by 2.3 mb/d in this time period. This rapid increase in production is affecting benchmark crude prices and spurring a midstream construction frenzy which is discussed in other parts of this report. Crude and condensate output growth from tight oil formations accounts for almost 90% of the increase in liquids output.

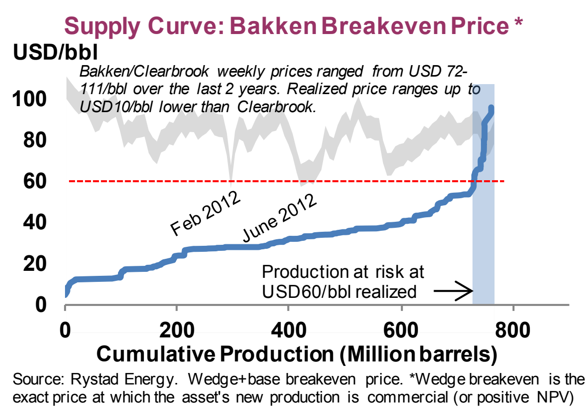


- **Changes from *MTOMR 2012*.** Production is ramping up much quicker than forecast due to sustained high prices and increased operator efficiency. Though the forecast 2017 target for US total crude production remains 0.3 mb/d higher than in October, at 8.4 mb/d, higher-than-previously-forecast production is expected from 2014-16.

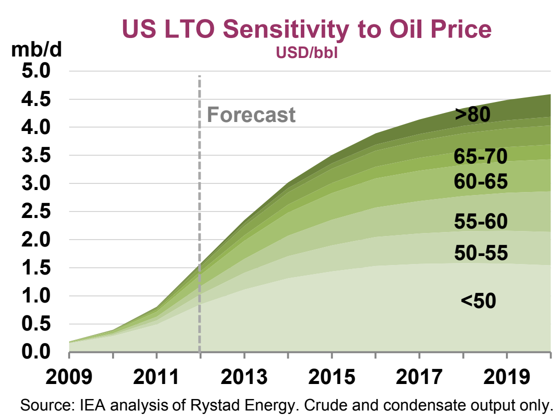
- **Tight oil developments.** At the more established tight oil plays, operators are getting better at targeting the sweet spots. Their use of pad drilling and multi-stage completion techniques also allows them to speed up development and cut the time between the initial spudding of a well and the sale of the first barrel of oil. Extended reach horizontal drilling has also reduced per well costs and enhanced productivity, though there are diminishing returns to even longer laterals. Operators are also using 'walking' drilling rigs to reduce the need for disassembling and reassembling the drilling rig.[1] Infill drilling, which increases the number of wells that are drilled in a given area, continues to be successful in the Eagle Ford and Bakken, raising output. At the same time, lack of available processing capacity limits development of newer plays outside of the Bakken and Eagle Ford. For example, a delayed start up of the Natrium natural gas processing and fractionation facility is slowing development in the much-touted Utica play in Ohio.

- **Cost inflation.** Upstream costs, as measured by the Bureau of Labor Statistics for foreign and US companies operating in the US, continued to increase in the last several months, though they are rising at a lower pace than in prior months of 2011 and 2012. The increase in oil prices has led to high revenues for oil companies. Companies have used these revenues to increase capital expenditures and thus raise demand for oilfield services and human resources.





- **Price sensitivity.** In past issues of the *OMR* and in the last *MTOMR,* we showed the average half-cycle breakeven price for select tight oil plays. It is important to keep in mind that the prices estimated by the model are average breakeven prices, but there will still be marginal, more costly assets whose economics would be challenged by a USD 10-20 fall. As oil prices fluctuate, it is reasonable to wonder what price level would drastically dampen crude oil production growth, keeping tight oil production levels at no more than 3.0 mb/d through 2018. In the chart below, left, the Rystad database estimates prices would have to stay within the



[1] For a discussion of recent technological developments see "STEO Supplement: Key drivers for EIA's short term crude oil production outlook." US Energy Information Administration. 14 February 2013.

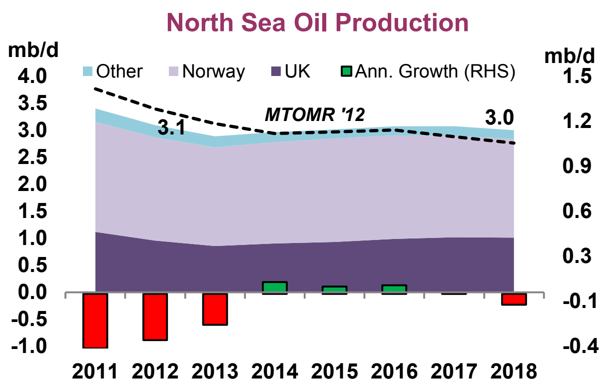
USD 60-65 range for this to occur. Moreover, as the chart at right shows, about 5% of current Bakken activity is at risk when realised oil prices drop to USD 60/bbl, which corresponds to Bakken/Clearbrook prices of around USD 65-70/bbl.

The medium-term outlook for natural gas plant liquids has not changed markedly since the MTOMR 2012 was released. In the US, NGL output is expected to grow by over 5% per year to 3.2 mb/d in 2018 as producers target liquids rich plays and need to process associated gas. The sustained growth in US liquids extraction has led to temporary stock excesses in the last year at both Conway and Mt. Belvieu NGL hubs which has depressed prices. In the medium term, however, new infrastructure to process both ethane and naphtha derived from lease condensate for petrochemical use is expected to lead to increased volumes (see *Trade* section '*How US condensate is changing the world*)'

North Sea

North Sea supply is expected to fall slightly from 3.1 to 2.9 mb/d as new fields offset declining production. Crude streams from Brent, Forties, Oseberg, and Ekofisk, which constitute the BFOE price benchmark, are expected to decline by 6% per year (CAGR) from 790 kb/d in 2012 to 500 kb/d by 2018. Unplanned outages in the North Sea dented output by -180 kb/d in 2011 and by -200 kb/d in 2012, but are expected to be lower in 2013. We see these years as exceptions, though for planning purposes we reduce output by -80 kb/d total throughout the forecast period. Companies that are active in the North Sea are connecting small, deep, and more remote fields to existing infrastructure, enhancing production efficiency, and reducing field development time. New field additions are explained in more detail below.

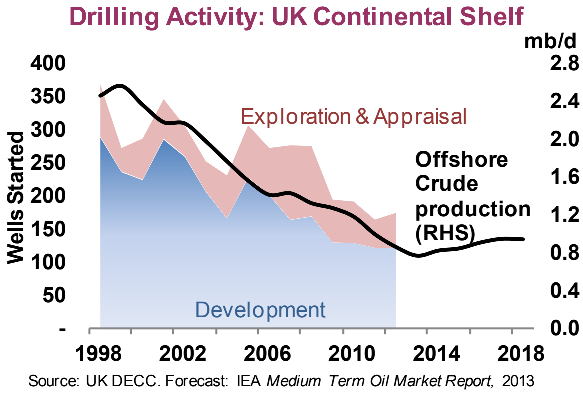
UK

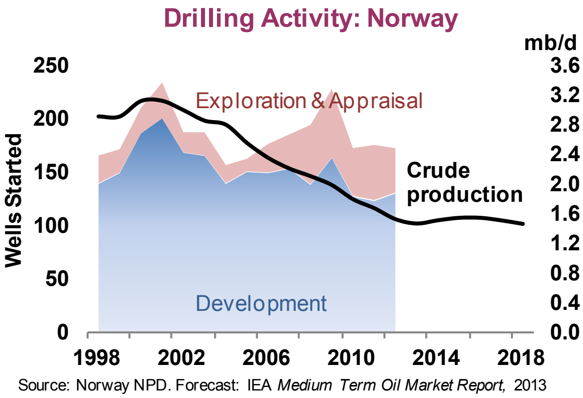


After years of decline, UK production is expected to grow by 40 kb/d to 1.0 mb/d in 2018, as new fields offset declining production at mature fields. Heavy maintenance and a string of unplanned outages had dragged down production in recent years, causing output to plummet by 8% in 2010, 17% in 2011 and 14% in 2012. Several of these disruptions have recently come to an end. The first several months of 2013 have seen Buzzard producing consistently at normal 200 kb/d levels and a resumption of flows from Total's Elgin/Franklin field that had been offline following a gas leak. The medium term may again see its fair share of unplanned outages, however – a possibility for which we attempt to account by trimming our bottom-up modelled output by 40 kb/d per year, not including additional adjustments for seasonal maintenance.

These adjustments notwithstanding, the UK is forecast to undergo a renaissance of sorts over the medium term, thanks to improved regulatory clarity and predictability. A recent report by industry body Oil and Gas UK noted that the continued uncertainty related to tax breaks for decommissioning played a key role in the reduction in asset transfers in the last couple years. The report showed that investment in an asset increases rapidly after the asset changes hands, as the new owners typically demonstrate higher risk tolerance, a clearer business strategy to leverage the asset, and a stronger financial position or commitment than their predecessors. The reduction in development drilling activity is partly a function of this need for policy certainty that the government is now meeting.

UK growth is expected to be centred in several major projects in the West of Shetlands area, numerous redevelopment projects, and some heavy oil fields. In the Brent and Ninian system, Thistle, Tern and Dunbar are expected to undergo redevelopment and add around 20 kb/d. The Forties field is expected to undergo redevelopment, and new production from the Andrew and West Franklin fields is forecast to add around 55 kb/d to Forties stream volumes during the medium term. The most significant expansions occur in the West of Shetlands area, which adds 260 kb/d in new production during the medium term. The Schiehallion field will go offline until a newly constructed 150-kb/d capacity FPSO, called Quad 204, is installed in 2016. In this area, BP's Clair field and Chevron's Rosebank (Lochnagar) project are expected to reach 150 kb/d by 2018. Statoil also made a final investment decision in December 2012 for its Mariner Area development at the Bressay, Kraken, and Bentley fields where it hopes to produce oil of 11 to 12 API.





Norway

Norway's production is expected to fall slightly in the medium term, by -1.4% on average (-160 kb/d total from 2012-18), to 1.75 mb/d in 2018. As in the UK, Norwegian operators are improving recovery rates at existing fields and unlocking new resources close to already-developed infrastructure. According to the Norwegian Petroleum Directorate, the development and use of new technology has improved the average oil recovery rate for producing fields to 46% from 40% in 1995. Also, operators have improved efficiency to enable production rates at much lower levels than the facility was originally designed.

New projects raise Norway's output in the 2015-16 range to more than 1.8 m b/d. Like the UK, development drilling in Norway has also increased in 2012 that will lead to multiple new projects in the medium term. Largest among them in the Haltenbanken are Norne, with a tieback from South Trost, and Goliat, which should lift output by 150 kb/d by 2016. The Ekofisk and Eldfisk redevelopment projects stand to reinvigorate output to over 200 kb/d in 2017 from around 170 kb/d currently. Several developments in the Sleipner-Frigg area, including Ivar Aasen and Gina Krog (formerly Eirin and Dagny), are expected to come online between 2015 and 2017 which should also raise production by around 150 kb/d. Statoil is planning at least 10 fast-track projects in the medium term that will add around 100 kb/d of new oil production. In 2015, a new NGL project at the Valemon field and a new gas compression facility at Mikkel will increase NGL output to around 320 kb/d by 2018 from current levels of 280 kb/d.

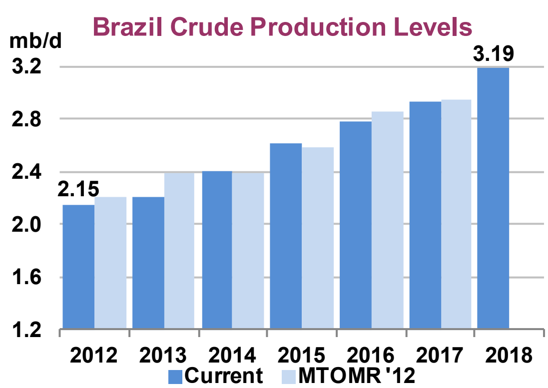
Latin America

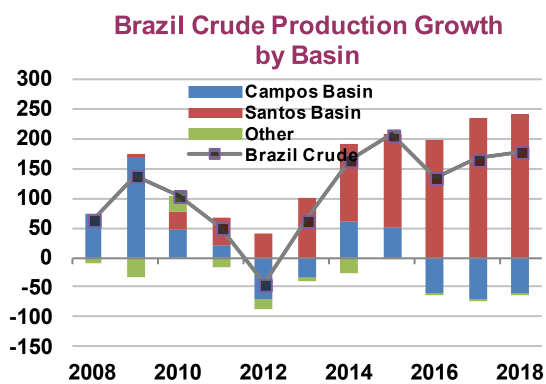
Brazil

Outside of North America, Brazil is expected to lead non-OPEC growth in the medium term, with production expected to jump by 1.0 mb/d to 3.2 mb/d by 2018. This would be a rebound from the small decline suffered in 2012, when production sagged by 2.1% (40 kb/d) due to protracted shutdown at Chevron's Frade field following a leak and other maintenance setbacks. The pre-salt area will account for the bulk of Brazil's production growth, with major contributions from the Lula, Sapinhoá (formerly Guará), Bauna/Piracaba and Parque das Baleias fields. The heavy-oil, post-salt Papa Terra offshore field will also contribute. Output from the pre-salt layers is expected to grow from around 14%, or 300 kb/d, of total output to around 30-35% by 2018.

Since the last MTOMR, Petrobras has revised its project pipeline by delaying several fields, and it has announced a capacity utilisation enhancement initiative called PROEF. After taking office in February 2012, Petrobras' new CEO, Maria das Graças Silva Foster, has adopted a more realistic view of the company's project schedule. Though some delays were taken into account in the prior report, the revised time schedule caused a further reduction to the outlook.

There are also two issues that have long term implications but are expected to be decided in the short to medium term: royalties sharing and the next licensing rounds. The government has not yet decided on how royalties would be distributed among oil and gas producing states and other states, creating uncertainty for the industry. It remains unclear whether the state-by-state distribution will shift or if there will be increases in the private contribution. This uncertainty comes during the time of the next set of licensing rounds. Although the rounds will not directly affect production in the 2018 timeframe, the long-awaited 11th licensing round, which will include pre-salt areas after a long hiatus, could have the potential to shift capital expenditures from development to exploration, depending on the ultimate results. Petrobras will be the operator of all pre-salt opportunities and will take a minimum 30% stake.

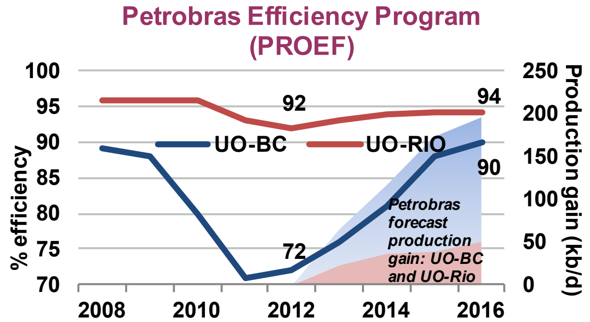




Managing carbon dioxide. One concern highlighted in the 2012 *MTOMR*, that of managing CO_2 content, seems to be under control for now. Carbon dioxide has been found in almost all of the wells drilled in the pre-salt in the Campos Basin. Petrobras is now using polymer membrane technology to strip the CO_2 from the field's gas stream (up to 20% at Lula and Sapinhoá) and reinject it to improve recovery rates. A pilot programme to use water-alternating gas (WAG) to enhance oil recovery is underway, and Petrobras expects results in 2014 that will help the company apply this technology in other areas of the pre-salt.

Other players. While Petrobras dominates the Brazilian oil patch, other players, including Chevron, OGX, QGEP, and Shell will also make their mark in the medium term. In the wake of the Frade field disruption, we expect further growth from Chevron-operated fields to be kept under 100 kb/d in the medium term. The company recently received permission to restart production. Shell plans to raise output at Argonauta North, part of the Parque das Conchas group, in 2014. OGX, however, had a disappointing year in 2012, with production missing its target by about 10 kb/d. The company is producing in shallow offshore waters of the Campos Basin in an Albian Carbonate reservoir. Some analysts suggest that the infrastructure procured was designed for much higher-than-expected volumes and is also causing problems with production. This is part of the reason for the downward revision to the overall Brazil forecast, as OGX's Waimea and Waikiki fields had been expected to produce well in excess of 150 kb/d by 2017. These expectations have now been scaled back.

Petrobras's efficiency programme (PROEF). Petrobras is planning to keep the impact of natural field decline rates in check via PROEF (Operational Efficiency Increase Program) through maintenance at the fields that will improve the integrity and reliability of production systems. Since the programme was implemented in April 2012 the company reports 25 kb/d in production gains on average in 2012. As a result of the newly announced programme, the almost 25 percentage point gain in efficiency is expected to lead to better production results in the medium term.

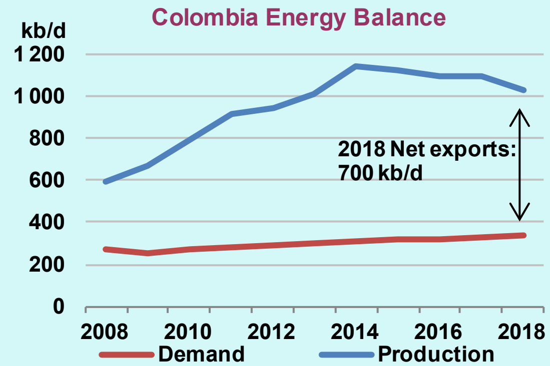


Source: Petrobras. UO-Rio includes Albacora Leste, Barracuda Caratinga, Marlim Leste, Roncador, and Marlim Sul (around 900 kb/d). UO-BC includes Marlim, Albacora and 27 other fields producing around 440 kb/d. PROEF program 'efficiency' is defined by Petrobras as the production level discrepancy between the natural decline rate and the operational capacity of the field.

Decline rates. Though the MTOMR forecasts production of around 3.2 mb/d in 2018, this is slightly more pessimistic than Petrobras's forecast and around 0.9 mb/d less than the Ministry of Energy's research arm EPE estimates for that year. We expect that assumptions about decline rates at existing fields, in addition to the potential for project delays and maintenance turnarounds, are part of the reason for the different views. *MTOMR* 2012's analysis of Campos Basin well-level Brazil decline rates concluded that in the first half of 2012, the median annual decline rate of post-peak Campos wells was -12% with a large degree of variability based on the start year. Pre-2008 vintage wells, currently accounting for 35% of output, were declining at around -8%. Subsequent analysis at an overall field level for the Campos Basin by Bernstein Research, which included the impact of infill drilling on field production, concluded that Campos Basin fields were declining at only 8% per year. Their study also assessed that post-peak Campos Basin wells were declining at -13%. On average, that meant that 130 kb/d of production would have to be added each year to keep Campos Basin production at end-2011 levels of 1.8 mb/d. Therefore, we assume that field production declines in the Campos Basin mitigate growth elsewhere. Production from pre-salt wells in the Santos Basin's Lula field, however, have been very minimal so the forecast assumes minimal declines at Lula and other Santos Basin pre-salt fields in the medium term.

Colombian output in the medium term dependent on security, transport, technology

Colombia is the second largest non-OPEC producer in Latin America after Brazil, producing almost 1 mb/d in 2012. Exploration has led to new proven reserves, which have raised Colombia's proven reserves at the third fastest rate in the world in 2011, behind only Iraq and Brazil. Colombia also has promising shale resources and with a new free trade agreement with the US in place, the country stands to benefit from oil services exports from the US tight oil boom. But in the medium term, Colombia's oil is heavy and getting heavier, and the country's pipeline capacity is constrained. To sustain government-targeted production levels of over 1 mb/d for the next several years, producers will need to increase investment with additional technology, the government will have to enhance security, and additional pipeline capacity is needed.

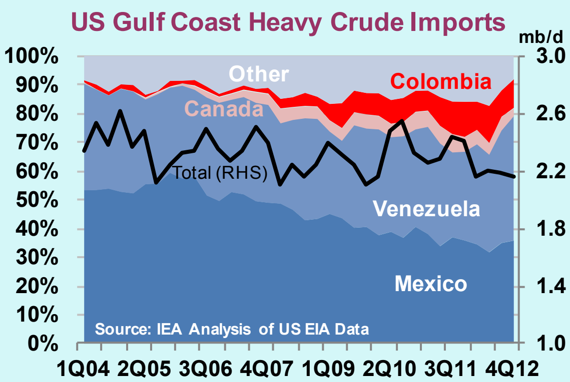


Reserves and production potential

Llanos Basin has majority of reserves, but remainder of the country is underexplored. Around 80% of Colombia's proven reserves are in the Llanos Basin, where around 70% of Colombia's oil is produced, but much of the rest of the country remains unexplored. In the medium term, exploration and development activity is likely to continue to increase in the Llanos Basin, but will also extend to the Catatumbo Basin, the Colombian portion of the prolific Maracaibo Basin, as well as the Lower and Upper Magdalena Basins.

Rubiales field production will determine Colombia's production profile. Medium-term production growth will come from the Castilla, Quifa, Cupiagua, Capella, and CPE-6 fields, dominated by three major companies: Ecopetrol, Pacific Rubiales, and Gran Tierra. Production from the heavy Rubiales field, Colombia's largest producer, is expected to fall from levels of around 220 kb/d to less than 80 kb/d by 2018 due to increasing water cut, keeping Colombian production rangebound between 1.0-1.1 mb/d through the end of the forecast period.

Thermal recovery in pilot stage. Pacific Rubiales and Ecopetrol are currently engaged in a pilot project called Synchronisation Thermal Additional Recovery (STAR) in the Quifa field in the Llanos Basin. The extent to which this technology can be used in other heavy oil production is a key unknown for the forecast as the companies test the applicability in the Quifa field. Since Pacific Rubiales is experiencing water cut levels of over 92% and stands to see a sharp decline in output from its flagship 200 kb/d Rubiales field, the application of this technology at that kind of field would enhance the recovery factor from current levels of around 10%. Pacific Rubiales is handling the higher water cut by constructing water treatment plants whereby the treated water will be used for palm oil plantation.



Colombian output in the medium term dependent on security, transport, technology (continued)

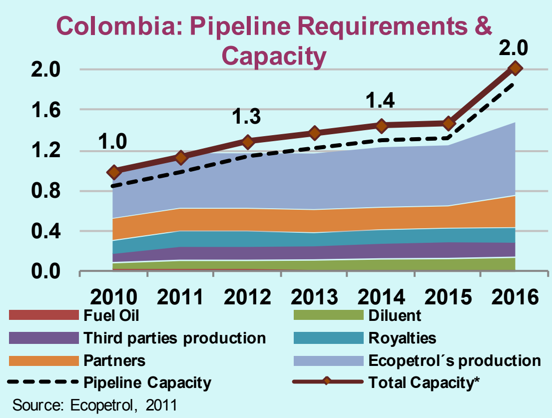
Shale holds promise. Companies are interested in acquiring acreage and drilling for shale oil in the Upper and Middle Magdalena Basin. Canacol, a Canadian company, recently announced deals with ConocoPhillips, ExxonMobil and Shell to explore in the La Luna and Tablazo plays in the basin. With thicknesses ten times the size of Eagle Ford and three to six times the size of the Vaca Muerta in Argentina, along with sufficient pressure and organic content, the plays have potential. As a first step, Canacol and its partners are planning to drill 19 wells to determine that viability. That said, as with any shale or tight play outside of North America, operators will need to find the commercially viable combination of geological factors and will need government support. The government has reduced royalty fees on unconventional drilling, and to facilitate oil field services imports the country has signed a number of free trade agreements including one with the US that came into force in May 2012.

Exports

Colombia produces several kinds of crude, ranging from heavy crudes of 12.5 API from the Rubiales field to light, sweet crude from the Cusiana, 380 kb/d of which are exported to the US in 4Q12. Amid recent production declines in heavy-sour Mexican Maya production and Venezuelan heavy production, other producers of heavy oil like Canada and Colombia are increasing production. Despite a 200 kb/d increase in Canadian bitumen production in 2012, US PADD 3 (Gulf Coast) imports of Canadian heavy oil actually fell by 40 kb/d in 2012 due to transport constraints. Colombia's oil has filled the gap, reaching a 10% share of the US Gulf Coast heavy crude import market.

Pipeline Plans. The lack of crude transport capacity has the potential to delay investment and keep production below 1 mb/d. Existing infrastructure also is inadequate for handling the diluents needed to transport heavy crude. In fact, Colombia had to import more than 30 kb/d of special naphthas for diluent from the US in January 2013. Ecopetrol forecasts that the design capacity of Colombia's transit infrastructure will reach 2.02 mb/d by 2016, up from 1.29 mb/d currently (which includes truck capacity). The latter level is only just enough to handle current volumes in different parts of the country. For example, of Pacific Rubiales' 120 kb/d of production in 2012, around 27% was shipped by truck. For some of the Llanos Basin crude, the company had to ship it at a cost of almost USD 50/bbl compared to USD 12/bbl using the OCENSA pipeline.

- Currently, the **Cano Limón-Coveñas** pipeline is limited to around 220 kb/d and is expanding a further 50 kb/d to take in incremental oil production from fields nearby fields.
- The **Llanos Orientales (ODL)** pipeline was expanded to 340 kb/d in 2012.
- Once the first of three phases of the 980-km **Bicentenario** line is operational in 2H13, adding 110 kb/d to 140 kb/d at a cost of USD 1.6 billion, more Llanos and Rubiales blend crudes will be able to flow to the Coveñas loading point.
- By 2014, an additional 1 mb/d of capacity is planned throughout the country, including a new **pipeline from Coveñas to a new port** being built near Cartagena.
- After 2014, there are plans to expand the **OCENSA** line from 585 kb/d to 800 kb/d and build a pipeline taking Venezuelan crude over 1 000 miles to a Pacific port to reduce dependence on the US Gulf Coast. Expansion of the **Bicentenario** line will bring capacity to 600 kb/d at a total cost of USD 4.2 billion.

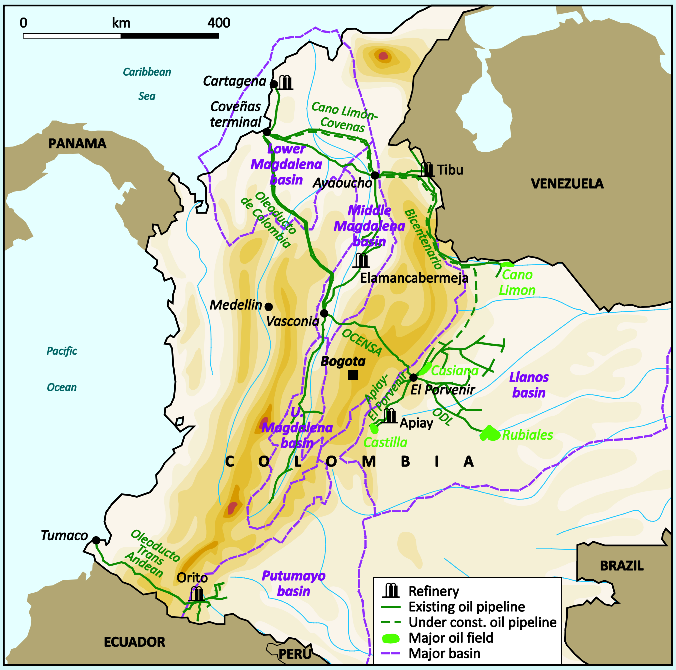


Colombian output in the medium term dependent on security, transport, technology (continued)

- Ecopetrol and Pacific Rubiales report that they are making progress on these lines, but slippage seems likely and would increase temporary reliance on trucking in certain areas. Therefore, due to the high cost of trucking, production in excess of 1.1 mb/d may not be sustainable until more pipeline capacity is available.

Challenges and Outlook

Security problems linger. Colombia has come a long way since 2000 when there was an average ten kidnappings per day and rebels from the Revolutionary Armed Forces of Colombia (FARC) controlled major highways and one-third of the territory. Government policy, along with a US military aid package called Plan Colombia, allowed country leaders to retake control and reduce violence. Though there is a clear downward trend in violence, there was an uptick in killings and kidnappings in 2012. According to Bogota-based consulting company Terra Consultores, suspected rebels (FARC) and the National Liberation Army (in Spanish, ELN) attacked Colombian pipelines 151 times in 2012, up 80% from 2011 levels. Kidnappings of oilfield workers were cut in half to 21 in 2012, but were mostly targeted workers on the Bicentenario pipeline. Peace negotiations are currently being held in Cuba and the FARC observed a two-month ceasefire from 20 November 2012 to 20 January 2013. Since the end of the ceasefire, however, the frequency of attacks has increased again.



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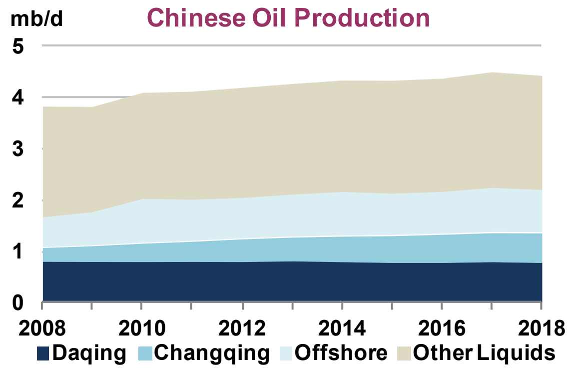
Government Policy. On one hand, the Colombian congress is considering raising all producers' royalties and tax oil by as much as 20%, but on the other hand it recently passed a new royalties law that would give unconventional oil and gas producers a 40% discount on the royalties and taxes paid by the rest of the industry. The tax break helped enhance the results of the 2012 Bid Round including blocks that contain shale where drilling is expected to begin this year. Companies are also complaining about the slow pace of environmental permitting that has dented exploration activity.

Outlook. Colombia's production stands to increase in the coming years but will depend on pipeline and oil workers security and in the country's ability to overcome transportation constraints. The uptick in violence 2012 is a worrisome - though we believe a short-lived trend. Possibly more worrisome for maintaining production in the medium to long term are the remaining pipeline bottlenecks and bureaucratic problems that have kept exploration activity below normal. And, much depends on the outcome of the pilot stage STAR work at the Quifa field because it could vastly increase the recovery rates at fields in production. Nonetheless, Colombia's heavy oil production plays a key role in US Gulf Coast refinery slates, especially in the absence of large Canadian volumes. As refineries process more light crude volumes, US Gulf Coast refiner demand for heavy crude for blending is likely to increase. But because Colombia's heavy crude competes with other heavy grades from Canada and Mexico, a key question is how much Canadian crude will PADD 3 refiners import in the medium term. That depends crucially on the fate of the Keystone XL pipeline and the economic viability of rail shipments to the US Gulf Coast.

Non-OECD Asia

China

China's oil production is expected to grow by 190 kb/d to 4.4 mb/d by 2018. The restart of ConocoPhillips' 150-kb/d Peng Lai field will offset mature field decline elsewhere in 2013. China's production is expected to grow as state owned enterprises increase offshore drilling and maximise production from complex conventional resources with international service companies. Infill drilling, satellite field development, and other improved oil recovery opportunities will increase Chinese production. More efficient development drilling has provided Chinese companies with better returns on their wells, and they are employing horizontal drilling techniques and hydraulic fracturing with the assistance of service companies in the low permeability reservoirs. For example, production at the Changqing field in the Ordos Basin continues to increase at over 10% per year, reaching 450 kb/d in 2012. CNPC has worked with Schlumberger to improve reservoir modelling, allowing the company to optimise fracturing design and well completion. Also, a CO_2 EOR project, sponsored by PetroChina, is underway at the Jilin field. Production has declined only 0.8% on average during 2009-12, after declining by a steep 10% from its peak of 130 kb/d in 2008.



India

India's production is expected to fall by around 100 kb/d (2% per year) to 800 kb/d in 2018, as new fields offset a broadly declining production base. The outlook is revised upwards by 100 kb/d from the last MTOMR due to new field announcements. India's government is focusing anew on stemming the decline at onshore fields and at the Bombay High facility offshore. Cairn recently announced plans to increase production from the Vasai West part of the Bombay High field, which is expected to keep average production level in upcoming years. India's production is expected to increase due to improved and enhanced oil recovery activity and increased drilling in the Rajasthan block where production currently comes from Mangala, Aishwariya, Saraswati, Taageshwari, and Bhagyam. The government has finally approved an increase of output from the fields in this region from 175 kb/d to 300 kb/d with infill drilling at Mangala and other additional output at Aishwariya and Bhagyam. Cairn recently said in a press statement that the company would invest USD 3 billion in capital through 2015-16 in the Rajasthan area.

Malaysia

Malaysia's production is expected to grow by 20 kb/d to 690 kb/d in 2018, with new fields offsetting declining production at mature fields. The most significant medium-term development since October has been the sanctioning of a new deepwater development called Malikai, albeit with a revised time schedule that expects production two years later than originally envisioned. Shell and its partners, ConocoPhillips and Petronas, now expect the platform to begin producing in 2016-17 and reach around 50-60 kb/d. This is the third deepwater project after Kikeh and Gumusut Kakap. Gumusut Kakap will also see increased volumes in 2014 as full scale production begins from 19 wells, raising output 100 kb/d to around 120 kb/d in 2015. Two other major projects include Lundin Petroleum's Bertam field, which is expected to begin ramping to 20 kb/d by 2015, and Petronas's Kebabangan gas condensate field. Finally, Shell and Petronas are working to bring online six new platform-based EOR projects in the Baram Delta and in the North Sabah area between 2013-15 that could help improve Malaysia's current recovery rates.

Other Asia

Vietnam's production is expected to rise by 40 kb/d to 400 kb/d in 2018, a 20 kb/d upwards revision from October due to new field announcements. Information on new projects is sparse, but Australia's Santos is planning to develop its Dua project, tied back to the Chim Sao platform. Petronas is also developing several gas projects with associated gas condensate as well as the 20-kb/d Ham Rong project.

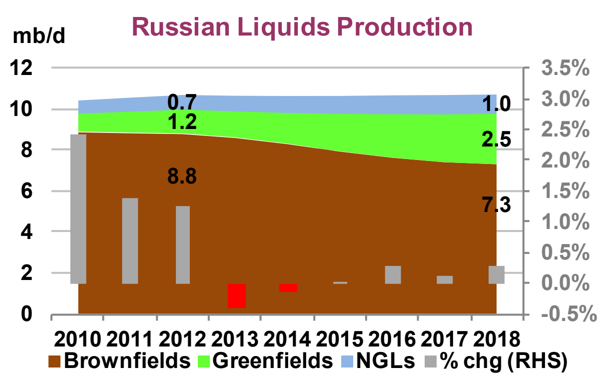
In **Indonesia,** the delayed Banyu Urip project is expected to ramp up to more than 150 kb/d in 2014-15, keeping the medium term average decline rate to around -3% per year and bringing output to around 750 kb/d in 2018. Indonesia's Pertamina estimates that production will quadruple by 2025 to 2.2 mboe/d, but most of these incremental volumes will come from gas output and from new acquisitions outside of Indonesia. The recent disbanding of BPMigas, the country's upstream regulator, adds new uncertainty to the investment climate in Indonesia. Pertamina, however, will continue to benefit from government support in the form of favorable terms for its production sharing contracts and pre-emption rights for expiring contracts.

Former Soviet Union

Russia

Russia is expected to remain the largest non-OPEC producer through 2014, after which it will be overtaken by the US. Though Russian companies have identified new planned projects in the past six months, significant uncertainty remains with respect to tax breaks on greenfield projects, the modification of the crude-product export duties (called 60-66-90[2]), and additional tax holidays for certain types of oil. Existing and proposed legislation is shown in the table below.

Liquids production in Russia is expected to increase to around 10.76 mb/d from around 10.73 mb/d as 1.3 mb/d in new greenfield production and improved oil recovery in low permeability conventional reservoirs offsets a 3.0% average decline in brownfield production. Gas condensate is expected to add around 300 kb/d over the course of the outlook.



Tight oil production in the Bazhenov layer seen at the end of the forecast period. Tax breaks for tight oil deposits are expected to spur development of this prospective resource. A number of company pairs including Gazpromneft and Shell, ExxonMobil and Rosneft, and Statoil and Rosneft announced agreements in the last year to jointly explore and test the commercial viability of the resource. Shell and Gazpromneft are planning to test the Palyanovskaya structure in the Bazhenov-Abalak layer of the Krasnoleninskoye field as well as the Salym field's Bazhenov layer. ExxonMobil and Rosneft are exploring the Bazhenov layer of the already-producing Priobskoye field, and Statoil and Rosneft are studying the Stavropol shale resource in southern Russia. We expect that tight oil production in Russia could total around 200 kb/d in 2018, which is a more conservative estimate than other forecasters but includes production from the Bazhenov and the shale source rock at Priobskoye. Russia's energy ministry estimates that production of tight oil in Russia could total from

[2] The first number (in %) is the maximum rate of marginal crude oil export duty. The number 90 (in percentage terms) refers to the export duty rate for gasoline relative to the duty for crude exports. The 66 (also in %) is applied relative to the crude export duty for all other refined products.

0.8 mb/d to 2.0 mb/d by 2020. Part of the difference in expectations is based on different definitions of what is "tight oil". For example the ministry may be including oil production from conventional reservoirs. Still, to meet these ambitious targets we assume that the government finalises its tax policy and that oil prices do not move drastically below current levels.

Mixed reviews: the 60-66-90 tax system. The system helped slightly improve the commercial viability of upstream projects, especially infill drilling and waterflood optimisation at brownfields, as the marginal rate of export duty was reduced from 65% to 60% (giving producers an average increase of USD 4.25/bbl). However, the 60% coefficient has not been confirmed by any regulatory act, so there is additional risk of modification in the future. In addition, the taxation of crude production is also complicated by the introduction of specific exemptions for the Mineral Extraction Tax (MET) and the export tax. The increase in production over the last year was more directly attributable to the increase in natural gas condensate volumes and greenfields. The brownfields' decline was already being stemmed before the introduction of the system due to the higher prices of crude oil. Therefore, as a recent study by the Energy Center of the Skolkovo Business School in Moscow concludes, it is a stretch to attribute 2012 production growth of 130 kb/d to the new system, but it is also untrue to deny it had any effect.

Further changes to the export duty ahead. Most importantly, after about two years of flux, the industry expected the 60-66-90 system to lead to more tax certainty. Instead, the government proposed adjusting the differentiated excise tax regime in March 2012 and April 2013, leaving vertically integrated companies uncertain about future investments. The latest proposal would raise the fuel export duty to 72% (from 66%) but would not raise the MET as the Ministry of Finance had proposed.

Russian Oil: Selected Existing and Planned Tax Breaks

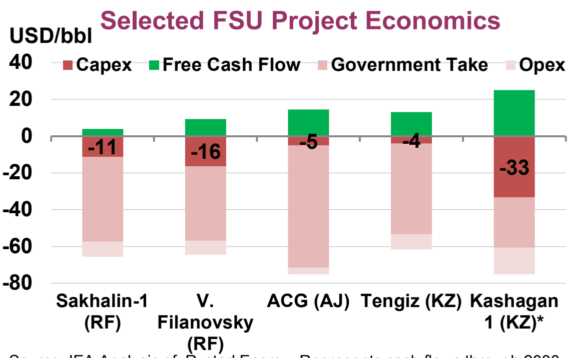
Location/Resource	Criteria	Duration	Status	Type of Exemption
Extra Heavy Crude Oil	Viscosity of >200 mPa-s	10 years	In place: 1 Jan '09	0 MET* rate 10% of standard export duty
Bazhenov Tight Oil	location	15 years from start of commercial development	Pending	0 MET rate
Other Tight Oil	Tyumen, Achimov, other, but depends on permeability and thickness of formation	10-15 years	Pending	20-40% of crude export duty
Small Fields	<5mmt recoverable reserves	unspecified	In place: 1 Jan '12	MET discount to 50% for a 1 mt oil field, with maximium of 60%
Depleted Fields	>80% depletion		In place: 1 Jan '07	applied reduced MET rate
E. Siberia	location - to include Yaraktinskoye, Danilov, Moarof, W. Ayanskoye, E. Talakan, Alinskoye fields	1st 10 years or first 25 mill tonnes depending on type of license, sometimes until 16.3% IRR is reached	In place: 1 Jan '09	0 MET rate, sometimes 0 export duty
Continental Shelf	location	unspecified (10 years or 35 million tons)	In place: 1 Jan '09	MET holiday
Arcitic Shelf	location	1st 10 years or first 35 mill tonnes (255mb)		0 MET rate, 0 export duty
Caspian and Azov Sea	location	1st 12 years or first 10 mill tonnes (73 mb). In some cases until an economic return of 16-21% is achieved.	In place: 1 Jan '09	MET reduction, 0 export duty
Black Sea	location	1st 10 years or first 20 mill tonnes (150 mb)	In place: 1 Jan '12	MET holiday
Okhotsk Sea	location	1st 10 years or first 30 mill tonnes (220 mb)	In place: 1 Jan '12	MET holiday
Yamal peninsula	location	1st 7 years or first 15 mill tonnes (110 mb)	In place: 1 Jan '09	0 export duty
Yamal Autonomous District	(N of 65^{o})	1st 10 years or first 25 mill tonnes (180 mb)	In place: 1 Jan '12	0 rate severance tax, no MET for gas condensate
Nenets Autonomous District (N. Timan Pechora)	location	unspecified		export tax break

Note: Exports of crude and products to Belarus or Kazakhstan are exempt from export duties.
Source: Ernst and Young Oil and Gas Tax Guide, Alfa Bank, Otkritie, Lukoil Annual Report. Press reports. *MET = Mineral Extraction Tax. Crude oil extraction tax rate is determined by adjusting the base rate depending on the international market price of Urals blend and the ruble exchange rate. The tax rate is zero when the average Urals blend international market price for a tax period is less than or equal to USD 15.00 per barrel. Each USD 1.00 per barrel increase in the international Urals blend price over the threshold (USD 15.00 per barrel) results in an increase of the tax rate by USD 1.61 per tonne extracted (or USD 0.22 per barrel extracted using a conversion factor of 7.33).

Government plans tax incentives to a number of resources including tight oil reserves and the Arctic shelf. Most export tax breaks will be dependent on whether a project's internal rate of return (IRR) is below 16.3%, but the government still has not given final approval and the formula to calculate the IRR is still unclear. It also remains unclear whether the export break would remain once an asset reaches the minimum profitability level. Additional production growth in the medium term is expected to come from higher output at Rosneft's assets in Eastern Siberia. Project slippage and uncertainty about taxation policies is likely to delay other greenfield projects like Gazpromneft and Rosneft's Messoyakha in Yamal-Nenets and Rosneft's Yurubcheno-Tokhomskoye in Eastern Siberia. Therefore, these new greenfields will add roughly 1.3 mb/d to Russia's output, partially offsetting around 1.5 mb/d in declines. A list of new major Russian greenfield projects is included in the *Tables* section.

Kazakhstan

In Kazakhstan, the first phase of the Kashagan field has been delayed by yet another year and is not expected to start producing at commercial volumes until 2014. The much-awaited start-up of the Kashagan field has involved five project delays, a 14-year project lead time, and a 2008 renegotiation with the Government of Kazakhstan over the contract terms. Phase 1's capital cost of around USD 30 billion is around 150% higher than originally envisioned in 2004. On a per barrel produced basis, this level far exceeds similar assets in the Caspian and in fields with challenging environmental and technical conditions offshore Russia. After the field begins commercial production, it should raise Kazakhstan's output to 1.8 mb/d in 2018, a 140 kb/d increase from 2012 levels.

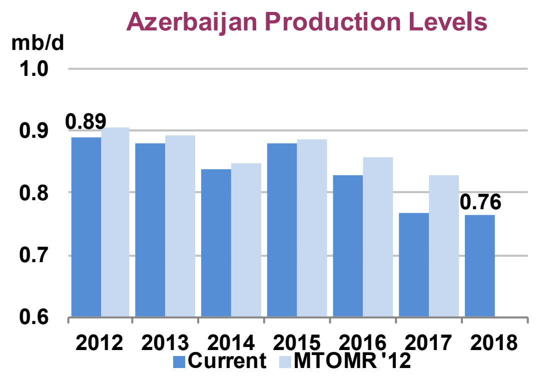


Source: IEA Analysis of Rystad Energy. Represents cash flows through 2030.
*Phase 1 only. Russian projects include a USD 50/bbl export duty

Declines at mature fields, including the giant Tengiz field and Kazmunaigaz's (KMG) assets, reduce the otherwise positive impact of new Kashagan output. Other major increments to production in the medium term are the third phase of the Karachaganak gas and gas condensate field. The KPO B.V. consortium that is developing the field has yet to agree on financing the next steps, though reports indicate that incremental gas production would be reinjected rather than marketed in order to enhance liquids volumes. Zhaikmunai is likely to contribute around 50 kb/d of new condensate and LPG by 2017 from new processing facilities at the Chinarevskoye gas field. Tengiz itself is in the queue for an expansion, and TengizChevroil expects to move to the engineering and design phase of what it calls the Future Growth Project (FGP)/Wellhead Pressure Management Project (WPMP) in the late 2013-14 timeframe. TCO will likely undertake the pressure management portion of the work first in order to maintain current oil production levels while construction of the FGP plant and new sour gas injection facilities are underway. This means that the FGP's 240 kb/d increment to the existing oil supply would likely fall outside of the medium-term timeframe.

Azerbaijan

Azerbaijani production stands to decline by 120 kb/d, or 2.3%/y, to 760 kb/d by 2018. The Azerbaijan International Oil Consortium which developed the Azeri-Chirag-Guneshli field was publicly



criticised for poor production performance by President Heydar Aliyev in 2012: a decline of 11% in 2011 and 4% in 2012. In fact, part of the production decrease was due to natural field decline and part of it was due to maintenance. We have therefore cut the medium-term forecast expectation by 20 kb/d on average due to a lower baseline estimate for 2012 and 2013. The declines at the ACG field, which accounts for 75% of the country's production, lowered Azerbaijani oil output to 890 kb/d in 2012, a 30 kb/d decline from the prior year. Production has rebounded by 50 kb/d to 900 kb/d in 1Q13, but is still 30 kb/d shy of 2011's average. Azerbaijan's production levels should increase by 2015 as the Chirag Oil Project comes onstream and additional wells are drilled, which will offset declines at other parts of the ACG complex. Gas condensate from Shah Deniz Phase 2 is also expected to add new volumes over the forecast period.

Middle East

Syria's and **Yemen's** production outlook is clouded by current geopolitical instability and we do not foresee an improvement in production over the course of the medium term. Yemen's production slides to only 80 kb/d from 180 kb/d in 2012 due to mature field decline and lack of new investment. As we await a resolution to the security problems with oil transport, this could be revised upwards. Syria's geopolitical situation is much more complicated, and in the absence of a resolution to the civil war and an absence of information about the state of the production facilities, we expect that over the medium term, production could return to 2012 levels of around 160 kb/d by 2018. In the early part of the outlook, Syria's production continues to fall.

In **Oman,** production is expected to increase from 920 kb/d to almost 1 mb/d in 2014, but then fall back to around 930 kb/d by 2018 as contributions from EOR projects fail to offset mature field decline. Oman is the only country where miscible gas, steam injection and chemical EOR technologies are all deployed. Oxy's Mukhaizna EOR project, currently at around 120 kb/d, has struggled to achieve the remaining 30 kb/d of output growth, so the project is now aiming for 140 kb/d. Oxy has had to reign in expectations for higher output because cost cutting measures on well monitoring backfired and resulted in the company having to drill additional injection wells, pushing the project costs four times higher. Other ramping EOR projects that should add around 40 kb/d in total in the medium term include the Qarn Alam fractured carbonate steam injection project and the Amal East and West steamflood, which will inject waste heat from a power station. Further increments are likely to come from EOR projects from several companies: Indonesia's Medco Energi-led consortium at the Karim field, Petrogas' Rima cluster of fields, waterflooding at Daleel Petroleum's Block 5 assets, and CC Energy Development's assets in Blocks 3 and 4.

Africa

There are two events of note since the last MTOMR. The first concerns the production outlook in **South Sudan and Sudan**, which has been revised upwards by a marginal 30 kb/d. The two sides have reached a comprehensive agreement on security and transit fees, and we expect a gradual resumption in production over the next few months. The possibility of conflict and lack of agreement on the Abyei area may destabilise bilateral relations and could continue to threaten oil production growth and long term investment in both countries. Before the agreement was reached, South Sudan had been eager to begin a near-2000 km pipeline to the port of Lamu in Kenya. Now that transit flows are expected to resume, it remains uncertain whether the South Sudanese government will continue to pursue this option.

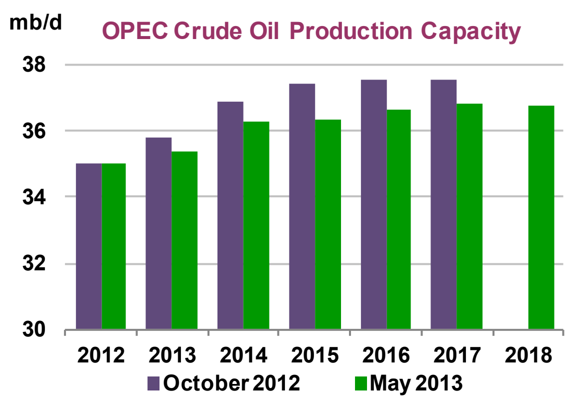
The second adjustment is related to a project delay for the Albert Basin in **Uganda**, which lowers output by 50 kb/d on average over the course of the outlook. The government has yet to approve the subsequent phases of development, and without the government decision, Tullow, the operator, cannot move forward. Uganda's government take is already a relatively high 85%, and the government is reportedly planning additional entry costs and is introducing tougher regulations.

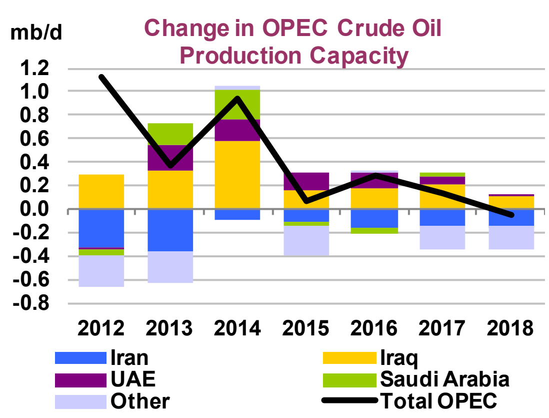
Production is expected to increase in **Congo**, with Total and Chevron's approval of the USD 10 billion offshore Moho Nord project. The company expects first oil in 2015, reaching up to 140 kboe/d (no breakout given) by 2017. In **Chad,** production from small Canadian producer Griffiths Energy is expected to add up to 30 kb/d in the medium term.

OPEC crude oil capacity outlook

Escalating security risks, political instability and unattractive fiscal regimes in a number of OPEC member countries are expected to take a toll on OPEC production capacity growth and have led to a downward revision to our assessment for the 2013-18 forecast period. OPEC capacity is forecast to rise 1.75 mb/d by 2018, to 36.75 mb/d, about 750 kb/d below our 2012 *MTOMR* estimate for the 2011-17 period. African member countries account for the lion's share of the downgrade in growth. Indeed, increased violence by Islamist extremists and militants, combined with political instability across much of North and West Africa since the start of the Arab Spring in 2011, is changing the equation for acceptable risks for international oil companies. Project delays are already apparent in Algeria, Libya and Nigeria.

The spill-over impact from Syria's civil war could yet have far-reaching implications for OPEC's Middle East producers Iran, Iraq, Saudi Arabia, Qatar, Kuwait and the UAE. In the past, however, OPEC as an organisation has largely managed to side-step political disputes involving its member countries, as was the case with the Iran-Iraq war and Iraq's invasion of Kuwait, with financial and budget imperatives a driving force in setting production policy.





OPEC spare capacity reassessed

OPEC's implied spare capacity edges higher over the forecast period, rising to a peak 7.18 mb/d in 2015 before tumbling to 6.38 mb/d by 2018. The IEA assesses current sustainable OPEC crude production capacity, which is defined as capacity that could theoretically be produced at the wellhead within 30 days and sustained at that level for 90 days. This installed capacity takes no account of short-term constraints such as maintenance or logistical issues.

OPEC Spare Crude Oil Production Capacity Outlook 2013-18

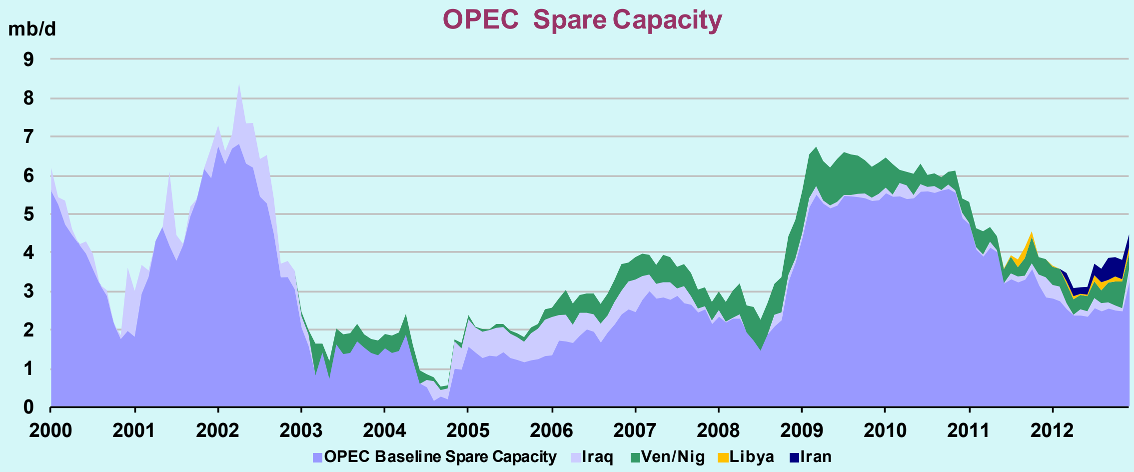
(million barrels per day)

	2013	2014	2015	2016	2017	2018
OPEC Crude Capacity	**35.35**	**36.30**	**36.37**	**36.66**	**36.80**	**36.75**
Call on OPEC Crude + Stock Ch.	**29.59**	**29.26**	**29.19**	**29.54**	**29.99**	**30.37**
Implied OPEC Spare Capacity[1]	5.76	7.04	7.18	7.12	6.81	6.38
as percentage of global demand	*6.4%*	*7.7%*	*7.7%*	*7.5%*	*7.1%*	*6.6%*
Changes since October 2012 MTOGM						
OPEC Crude Capacity	**-0.42**	**-0.60**	**-1.05**	**-0.89**	**-0.75**	
Call on OPEC Crude + Stock Ch.	**-0.55**	**-1.12**	**-1.13**	**-1.12**	**-1.22**	
Implied OPEC Spare Capacity[1]	0.12	0.52	0.09	0.23	0.47	
as percentage of global demand	*-1.3%*	*-1.5%*	*-1.0%*	*-0.5%*	*-0.6%*	

[1] OPEC Capacity minus 'Call on Opec + Stock Ch.'

Starting with this *MTOMR*, we have removed the 'effective' spare capacity projection after reassessing the methodology for the medium term. Previously the IEA's estimate of 'effective' spare capacity recognised that over the last decade, and on a consistent basis, around 1 mb/d of nominal spare capacity in countries including Iraq and Nigeria, has not been immediately available to the market for technical, security-related or infrastructure reasons. This observation has been reflected in the calculation of effective spare capacity, *i.e.* a 1 mb/d discount was applied to projected 'implied' OPEC spare capacity for the future period. The latest data show uneven swings in the portion of nominal capacity not immediately available to the market for unforeseen reasons which made it inconsistent with our previous estimate of nominal spare capacity. In addition, Nigeria and Venezuela accounted for a significant portion of capacity not available to markets, however, we have now lowered the baseline estimate for Nigeria to reflect companies' decisions to permanently shut-in capacity.

For the monthly report, however, we will maintain calculating an 'effective' spare capacity estimate to reflect as accurately as possible an assessment of current available capacity available that can be brought on line in 30 days and maintained for 90 days.



In addition to above-ground political and security risks, OPEC is grappling with mature fields and accelerating decline rates. Enhanced oil recovery projects and other advanced technology are needed to maximise recovery rates, but a number of countries lack the appropriate contract terms to attract foreign partners.

OPEC is now forecast to provide 30% of the net 8.2 mb/d increase in global oil supply capacity over the 2012-18 period, including crude, condensate and other liquids. Iraq, the UAE, Saudi Arabia and Angola are the key contributors to the group's net capacity increases, with Venezuela, Qatar and Nigeria providing smaller increments. By contrast, five countries are expected to see capacity decline, with Iran off by more than 30% by 2018 compared to 2012 levels. New capacity will be partially offset by annual field decline rates of around 1 mb/d, or 3% from the existing production base. *MTOMR* capacity estimates are based on a combination of new project start-ups, and assessed base load supply, net of mature field decline. Decline rates are in line with historical trends of around 1.1 mb/d for the forecast period but the outer years see a sharp short fall in start-ups, in part due to lower capital expenditures.

OPEC producers are also facing headwinds from the shale oil and gas boom in North America. There has been a pronounced shift in capital expenditures from OPEC to non-OPEC countries, especially to tight oil projects, in the medium term. From 2006 to 2012, OPEC capex grew by about 50% compared with 90% for non-OPEC producers, according to Rystad Energy. Going forward non-OPEC capex grows 20% from 2012-18 while OPEC capex posts 30% growth, causing OPEC's average share of global capex to slip to below 22% from 24% previously. On OPEC's part, a number of countries are exploring shale gas development, including Algeria and Saudi Arabia.

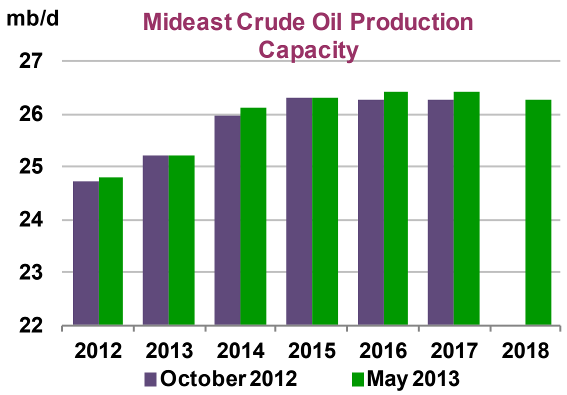
Estimated Sustainable Crude Production Capacity

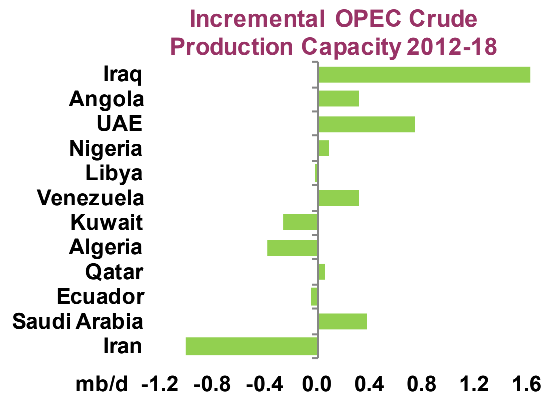
(million barrels per day)

Country	2012	2013	2014	2015	2016	2017	2018	2012-18
Algeria	1.20	1.14	1.09	1.02	0.94	0.88	0.82	*-0.38*
Angola	1.84	1.86	1.94	2.03	2.05	2.11	2.16	*0.32*
Ecuador	0.51	0.51	0.51	0.51	0.51	0.49	0.47	*-0.04*
Iran	3.39	3.02	2.93	2.81	2.66	2.51	2.38	*-1.01*
Iraq	3.18	3.52	4.10	4.26	4.43	4.64	4.76	*1.57*
Kuwait	2.78	2.85	2.86	2.82	2.79	2.65	2.52	*-0.26*
Libya	1.50	1.57	1.64	1.56	1.50	1.51	1.48	*-0.02*
Nigeria	2.57	2.48	2.35	2.32	2.50	2.60	2.66	*0.09*
Qatar	0.76	0.74	0.73	0.77	0.82	0.83	0.82	*0.06*
Saudi Arabia	11.97	12.17	12.43	12.39	12.33	12.36	12.35	*0.38*
UAE	2.70	2.91	3.08	3.23	3.37	3.43	3.44	*0.74*
Venezuela	2.58	2.60	2.64	2.65	2.76	2.77	2.90	*0.31*
OPEC-11	**31.81**	**31.84**	**32.20**	**32.12**	**32.23**	**32.15**	**31.99**	*0.18*
Total OPEC	**35.00**	**35.35**	**36.30**	**36.37**	**36.66**	**36.80**	**36.75**	**1.75**

Middle East capacity ebbs and flows

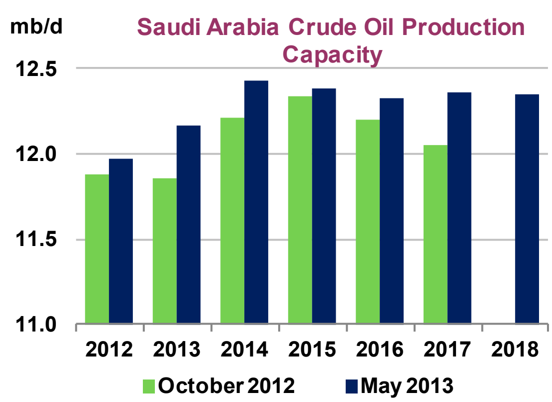
OPEC's Middle East producers have largely been left unscathed by the instability emanating from the Arab Spring, but broader political turmoil involving Iraq, Syria and Iran continues to pose potential downside risks to the region's forecast. OPEC's Middle East crude oil capacity is forecast to rise by a net 1.48 mb/d to 26.27 mb/d by 2018, with Iraq, Saudi Arabia and the UAE more than compensating for a steep, sanctions-induced decline in Iran.





Heightened political unrest in Iraq, if continued, may delay Baghdad's ambitious expansion plans, however (see '*Iraqi production growth tempered by political and bureaucratic woes*'). The standoff between Tehran and the international community over the former's nuclear ambitions also continues to be a source of uncertainty, while new wide-ranging sanctions on Iran's finance and oil sectors further threaten the country's crude oil production outlook.

Against the background of political and security risks to Iraqi and Iranian capacity, Saudi Arabia announced in 1Q13 new project plans that will bring an additional half a million barrels a day plus online over the next five years, on top of a previously announced expansion of 900 kb/d. The UAE is also powering ahead with expansion plans. Qatar capacity increases marginally as new project developments offset natural decline rates while in Kuwait a lack of progress at the political level on agreeing an investment framework for IOCs continues to undermine the country's outlook.



Saudi Arabia continues to flex its production muscle and remains the single largest holder of spare capacity. Riyadh unveiled new plans in early March to expand capacity at several oil fields, bringing total *gross* additions to 1.45 mb/d over the forecast period. Saudi crude production, however, is forecast to rise by around a *net* 380 kb/d to 12.35 mb/d by 2018, with new capacity largely offsetting mature production as Saudi Aramco plans to rest some old workhorse fields until new technology improves extraction and recovery rates. New expansion plans include a 300 kb/d upgrade to the 1.2 mb/d Khurais field, which produces Arab Light crude, starting in 2016. The 1.2 mb/d Khurais field was brought online in 2009 and to date remains the largest single incremental capacity increase in history. The company also dusted off plans to raise Arab Extra Light crude output at the Shaybah field by 250 kb/d, from the current 750 kb/d, in 2016.

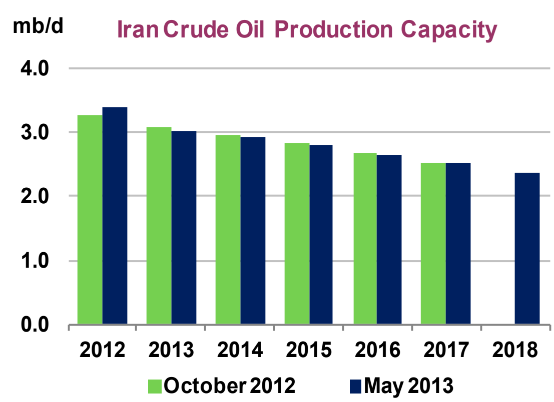
The offshore, shallow water 900 kb/d Manifa field started production three-months earlier than planned in April 2013, with the first 500 kb/d expected to be reached by July and the second tranche of 400 kb/d online at end-2014. Saudi Aramco has said that the heavy Manifa crude will largely offset natural field declines elsewhere and enable the company to mothball older fields that are more expensive to operate. Production from Manifa will be committed for processing at the country's three new refineries coming online during the forecast period. The first tranche will supply Aramco's 400 kb/d refinery joint venture with Total at Jubail slated to come on in late 2013 as well as its Yanbu Aramco Sinopec Refining Company (YASREF) joint venture with Sinopec, which is expected online in 2014. YASREF will process 400 kb/d at the west coast plant on the Red Sea. Later, Manifa is expected to also help supply the 400 kb/d Jazan refinery in the southwest of the country when it is completed in 2016.

Saudi Project Developments

Planned	Year	kb/d
Manifa 1	2013	500
Manifa 2	2014	400
Khurais	2016	300
Shaybah	2016	250
Total		**1,450**
Future Potential		
Zuluf	?	900
Safaniya	?	700
Berri	?	300
Total		**1,900**

Saudi Aramco's current programme of work is designed to maintain production capacity within a 12.2 mb/d to 12.5 mb/d range rather than boost overall capacity, and includes new drilling as well as major rehabilitation of currently producing fields. The rehabilitation of infrastructure at Safaniya, the world's largest offshore oil field, has been underway since 2012 and is designed to maintain the field's heavy oil production at around 1.2 mb/d. Plans include installation of new submersible pumps as well as upgrading of crude-gathering facilities and power supply operations. Safaniya has been in production since 1958 and has the potential to add a further 700 kb/d of new capacity if needed. Several years ago Aramco identified three additional fields that could add a further 1.9 mb/d if warranted, including Safaniya. Other upgrades put on the drawing board include an additional 900 kb/d of Arab Medium crude from the Zuluf field and 300 kb/d of Arab Extra Light from the Berri field.

Iran's production capacity is forecast to decline by 1 mb/d in the medium term, to 2.38 mb/d by 2018. This *Report* assumes that the far-reaching US and European Union sanctions imposed on Iran's oil, financial and insurance sectors in 2012-13 will have a significant impact on the country's crude oil production outlook in the medium term. Production fell to a three-decade low of 2.65 mb/d in early 2013. Crude exports tumbled to around 1 mb/d on average in 1Q13, compared to 1.5 mb/d in 2012 and 2.5 mb/d in 2011. The decade-long dispute over Iran's nuclear development plans saw a flurry of negotiations in recent months but positions still remain far apart. This *Report's* projections assume a continuation of the status quo over the forecast period.

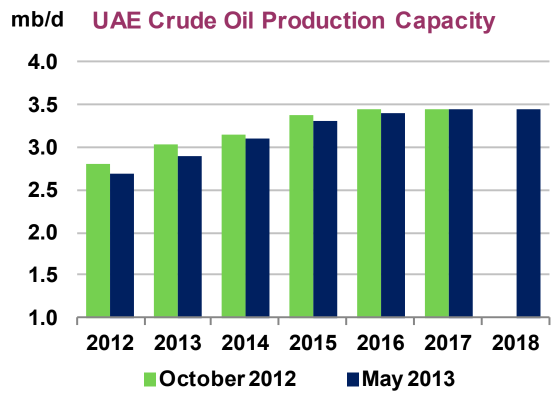


US and EU sanctions have had an immediate market impact on crude exports, but they are also putting a stranglehold on Iran's oil production capacity in the medium term. State National Iranian Oil Company's (NIOC) finances have been severely strained, limiting the company's ability to fund even routine field maintenance work, infrastructure repairs and planned projects. As expected, cash flow problems have also severely constrained Iranian companies' ability to procure equipment and other needed materials. In response, Iran's decline rate of 8% to 10% in recent years is expected to accelerate in the medium term. Additional sanctions implemented in February 2013 effectively bar Iran from repatriating earnings from its oil exports, depriving Tehran of much needed hard currency. As with all other sanctions, countries that violate the new requirements risk being expelled from the US financial system, among other penalties.

More than half of Iran's crude oil production is from fields discovered more than 70 years ago, and are costly to operate. Iran started producing crude oil in significant quantities by the late 1940s with four major fields—Agha Jari, Gachsaran, Naft Shahr and Naft Safid—and all are still in operation. Production peaked in 1974 at just over 6 mb/d. Recent reports suggest NIOC may soon have to start mothballing the older, more expensive fields to operate given the lack of funds to maintain operations.

Planned expansion of capacity at existing fields continues to be delayed by lack of technology and equipment. Development at the offshore Foroozan field has been postponed again, to 2014 at earliest now. A 60 kb/d of capacity at Foroozan was initially slated to be on stream in 2008. NIOC has pushed back the date with only small incremental volumes expected to start in late 2014. The Yadavaran field, a joint venture with Sinopec, has also repeatedly seen its timeline pushed back. Current production of 20 kb/d was forecast to rise to 85 kb/d in 2012 but Sinopec has revised its plans and is now shooting for late 2015/2016. The second phase development of Yadavaran, of an additional 100 kb/d, has now been removed from our forecast. The two-phase development of the Azadegan field with CNPC has also been delayed from 2013 and now pencilled in for 2015. The first phase is expected to add 75 kb/d to Iran's capacity. The second phase, for an additional 75 kb/d, is now not expected online until after 2018. Smaller developments such as the 35 kb/d South Pars has been pushed back to 1Q15 from 2013.

The **UAE's** crude oil production capacity is on course to rise by a net 735 kb/d, to an average 3.44 mb/d by 2018, close to the country's 3.5 mb/d target for the period. All capacity expansion plans are in Abu Dhabi. Abu Dhabi's onshore capacity expansion via water and gas injection development projects at mature fields was slated to come online in 2012 but was delayed until 1Q13 and will ultimately add around 250 kb/d to capacity by 2015.

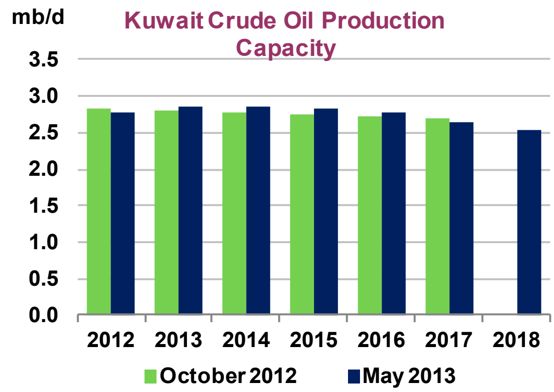


UAE offshore production capacity is forecast to increase by around 500 kb/d with the expansion of both the Lower and Upper Zakum fields and start-up of two new fields. Lower Zakum is expected to add 125 kb/d, bringing total field capacity to 450 kb/d in 2014. Expansion of Upper Zakum field is slated to start in 2015, rising by 200 kb/d to 750 kb/d. Development of the offshore Umm Lulu and Nasr fields combined will add a further 165 kb/d. First oil from Umm Lulu is expected in 2016 for a maximum capacity of 100 kb/d. The start up of Nasr will follow in 2017 at a smaller 65 kb/d.

Uncertainty surrounding Abu Dhabi's renewal of legacy concession contracts, however, is injecting downside risk. The country's onshore concessions were scheduled to expire in 2014 and offshore concessions in 2018. Shareholders had expected a decision five years ago. The delay has led to project slippage and under investment in fields. In early 2013 the Abu Dhabi National Oil Company (ADNOC) requested the onshore concessions be extended by a year so the Abu Dhabi Company for Onshore Oil Operations (ADCO) can review all its options. ADCO is owned by ADNOC (60%), BP, Shell, ExxonMobil and Total with 9.5% each and Portugal's Partex with 2%. Among the shareholders, only Partex has not been invited to renew its contract.

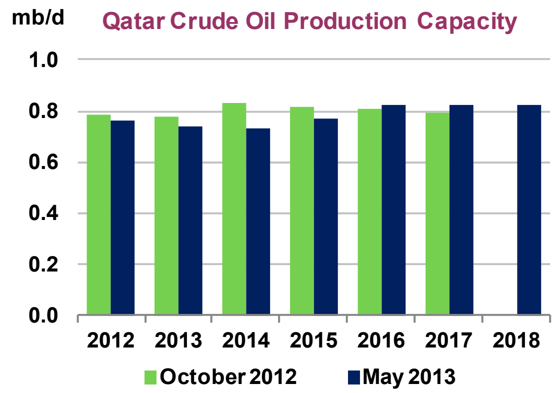
The major shareholders will likely have to wait until 2015 to learn whether their stakes will be renewed or cancelled, delaying investment plans in the medium term. ADNOC has petitioned the Emirate's Supreme Petroleum Council for a year-long extension while it considered whether to split the fields into separate concessions with several partners, reduce current shareholders' stake or award concessions to new companies. Current shareholders argue that breaking up the concessions is not an attractive option given the requirement that they would then have to share the latest proprietary technology with other foreign operators, especially in light of the very modest USD 1/barrel profit. ADCO produces from six oil fields: Asab, Bab, Bu Hasa, Sahil, Shah and North East Bab. The IOCs selected will need to possess significant experience in enhanced oil recovery (EOR) given the country's complex, ageing geology.

Kuwaiti crude oil production capacity is forecast to fall by 260 kb/d to 2.53 mb/d by 2018 given the dearth of development projects in the medium term. Kuwait had targeted an increase in capacity to 4 mb/d by 2020 but this is no longer viable. Chronic infighting within the Parliament over potential contracts for future development of the oil sector continues to constrain capacity. Kuwait last saw a boost in production capacity of some 300 kb/d from the giant Burgan field in 2010-11 after successfully debottlenecking infrastructure at the Mina al-Ahmadi terminal.



Plans to adopt enhanced technical service agreements (ETSA) for the northern fields have not progressed since last year. The proposed ETSAs are expected to eventually raise production in the northern region of the country, which includes the Ratqa, Raudhatain, Sabriyah, Abdali and Bahra fields. Progress has been made, however, with the heavy oil Lower Fars project in the north. In late 2012, Kuwait Petroleum Co (KOC) issued tenders inviting IOCs to bid on the project, with a decision planned for May 2013. Start-up of the Lower Fars project has been officially set for 2017 but expected delays mean production is not likely until post 2018.

Expansion projects are also stymied by the lack of natural gas needed for reinjection to maintain reservoir pressure. Kuwait signed an ETSA with Shell in February 2010 for the development of the Jurassic Gas fields in the northern region of the country but technical and legal issues have delayed the development.



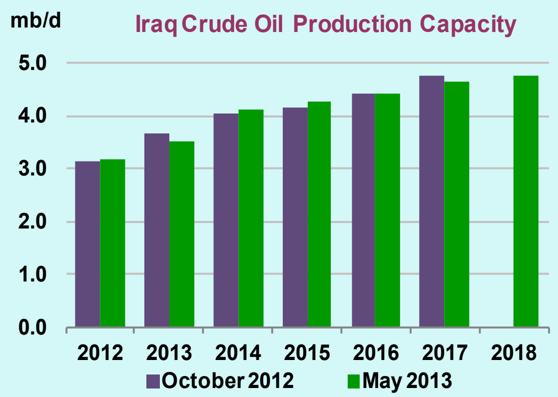
Qatar's crude oil production capacity is forecast to rise by around 60 kb/d to 820 kb/d by 2018. Current projects in the pipeline include raising capacity at the onshore Dukhan field by 75 kb/d to 300 kb/d in 2015 while the Bul Hanine field will be doubled to 90 kb/d in 2016. Current plans fall short of Qatar's stated target to reach 1.1 mb/d. In an effort to attract investor interest, Qatar Petroleum (QP) has invited companies to submit redevelopment plans to increase capacity at existing fields as well as increase recovery rates via a concession type contract versus the existing production sharing model.

The country is also reviewing options to rehabilitate the challenging al-Shaheen field, which has been producing well below planned capacity of 500 kb/d at 300 kb/d due to complex geology with multiple thin pockets of oil. Operator Maersk, whose contract expires in 2017, has submitted a USD 1.5 billion proposal to develop new wells at Al Shaheen aimed at sustaining current production rates. A new concession-type contract will enable QP to contribute financing for the project in a bid to offset the cost for the foreign operators. Qatar's development costs are relatively steep given difficult geology and the country's needs to attract partners with the most advanced technology.

Iraqi production growth tempered by political and bureaucratic woes

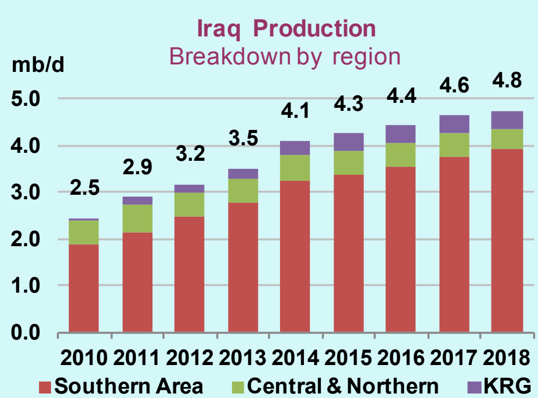
Iraq's crude production capacity growth is forecast to increase by 1.57 mb/d to 4.76 mb/d by 2018, with expansion plans in the near term constrained further by daunting above ground hurdles, and complex below ground challenges in the medium term. Insufficient institutional capacity at the administrative and organisational levels continues to cause excessive delays to contract awards for infrastructure needed to support project development. A shortage of skilled workers is also tempering the outlook. As a result, production capacity has been trimmed by 110 kb/d from the 2012 *MTOMR.*

Iraq raised capacity between 2010-12 by 365 kb/d on average to 3.18 mb/d following start up of three mega projects, Rumaila, West Qurna and Zubair. The ramp-up in production stalled in early 2013. In the south, contract awards on an *ad hoc* basis have led to bottlenecks across the export chain. Output from the northern Kurdistan region was also halted due to the conflict between Baghdad and Erbil over primacy for oil policy and export agreements. Rising sectarian violence, especially in the capital, is also an issue for companies.



The government is considering lowering its production plateau from the 12 mb/d contractual target in 2017 to 9 mb/d by 2018, ostensibly due to expectations that surging non-OPEC supply coupled with modest global demand growth will reduce the call on OPEC, including Iraqi supplies. The formidable challenges, however, are also giving companies cause for a pause given the steep investment needs in light of the relatively poor financial returns and worsening security issues. IOCs receives a modest USD 1.15 to USD 2.00/bbl fee at the projects.

Under current proposals being debated in Baghdad, the five largest projects would see their targets negotiated lower by about 30%, with the smaller field developments unchanged, while at the same time the government would extend the contract period to compensate for the lower levels. This would also improve long-term field management by extending the period of plateau production. Negotiations, however, with the IOCs are proving complicated, with a number of companies arguing the per barrel fee remuneration must be raised given the difficult investment and operating climate.



Iraqi production growth tempered by political and bureaucratic woes (continued)

Iraq's Contract Awards & Production Targets

(thousand barrels per day)

Contract Awards	Companies	Target Capacity	Production Increment	Estimated Target Cut*	Potential Target	Fee Paid (USD)
Rumaila	BP, CNPC	2 850	1 800	855	1 995	2.00
West Qurna 1	ExxonMobil, Shell	2 825	2 065	848	1 978	1.90
West Qurna 2	Lukoil, Statoil	1 800	1 800	540	1 260	1.15
Majnoon	Shell, Petronas, Missan Oil Co	1 800	1 754	540	1 260	1.39
Zubair	ENI, Occidental, Kogas	1 200	1 017	360	840	2.00
Halfaya	CNPC, Total, Petronas	535	535	0	535	1.40
Garraf	Petronas, Japex	230	230	0	230	1.49
Badra	Gazprom, Kogas, Petronas, TPAO	170	163	0	170	5.50
Qairyarah	Sonangol	120	120	0	120	5.00
Najmah	Sonangol	110	110	0	110	6.00
Missan	CNOOC, Turkish Petroleum	450	350	0	450	2.30
Total		**12 090**	**9 944**	**3 143**	**8 948**	

**Estimate based on preliminary discussions*

The oil ministry's overall target even when cut to 9 mb/d, however, still appears over-optimistic given the multitude of political, institutional, security challenges as well as transport and oil field infrastructure hurdles. Rising operational costs will also require staggering levels of investment by both the government and IOCs to ramp-up production capacity. The annual investment need is highest in the current decade, at on average more than USD 25 billion per year, a significant step up from the estimated USD 9 billion invested in Iraq's energy sector in 2011, according to an in-depth analysis of Iraq's energy outlook in IEA's annual 2012 *World Energy Outlook (WEO)*. In order to meet the 9 mb/d target, a total of roughly USD 125 billion is needed over the forecast period.

Raising production capacity to our 2018 forecast still requires a herculean effort to resolve major problems. In the southern and central parts the infrastructure bottlenecks and chronic delays in a major water injection project needed to maintain reservoir pressure are curbing our forecast. Iraq formally announced the start-up of two 900 kb/d Single Point Moorings (SPM) that link to the key onshore Fao terminal in the Gulf in March 2012 but capacity is less than half of that level. Capacity is constrained by the lack of supporting pipeline network, pumping stations and storage facilities. The dilapidated southern ports have meant IOCs are unable to import the massive amount of equipment needed to develop and operate their projects. BP signed in 1Q13 a five-year contract to build a new terminal at the southern port of Khor al-Zubair to help ease the flow of equipment as well as refined product imports. A 1 mb/d Basra-Aqaba pipeline also appears to be moving forward, which will eventually help take the pressure off the southern port facilities. The shortage of port capacity, coupled with delays in rehabilitating pipelines and pumping stations moving crude to Fao may force IOCs to curb output over the next several years.

Second, the massive Common Seawater Supply Facility (CSSF), which will treat and pump seawater from the Gulf to the inland fields, including Rumaila, West Qurna-1, West Qurna-2, Zubair and Majnoon, faces further delays. ExxonMobil was initially tapped to coordinate the project but withdrew in early 2012, and now the government has appointed a new consultant. Given the sheer volume of engineering work required and bureaucratic issues, the project is not expected to be operational until post-2018, with end-2019 more probable. The oil ministry has also been grappling with how to fund the project.

Thirdly, excessive bureaucracy, coupled with a shortage of skilled workers, is hampering the outlook. Once cost recovery production levels are reached the government is required to take over maintaining investment levels, which companies fear will not be as forthcoming as needed given the administrative and organisational problems at the ministry level. Against this backdrop, production in the southern and central region is seen rising from 3 mb/d in 2012 to an average 4.35 mb/d in 2018.

Iraqi production growth tempered by political and bureaucratic woes (continued)

The North-South divide

The long-running debate between Baghdad and the Kurdistan Regional Government (KRG) over primacy for oil policy, resource development and export agreements is slowing development of one of the most attractive frontier regions in the world. The KRG awarded close to 50 contracts with IOCs, including majors ExxonMobil, Chevron and Total, much to the chagrin of Baghdad. The KRG has estimated that production could reach 1 mb/d by 2015 but a host of legal and geopolitical issues with Baghdad is constraining development, not the least of which is that the central government has suspended payments for IOCs operating in the northern region. In response, since the start of 2013, the KRG has halted exports via the Kirkuk-Ceyhan pipeline, which Baghdad controls.

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.

Baghdad's control of the Kirkuk-Ceyhan pipeline, which carries crude to the Turkish Mediterranean Coast effectively forces the KRG to shut-in output. The KRG has increased use of trucks for exports via Turkey and has begun to build a new pipeline, which has furthered entrenched the stand-off between the north and south. KRG intends the new 150 kb/d link from the Taq Taq field to the existing Iraq-Turkey crude pipeline in Turkey to be completed in 4Q13. Early reports suggested Turkey signed off on the pipeline but strong political objections from Baghdad and the US to Ankara allowing large-scale exports of KRG crude through its territory appear to have stalled the plans for now.

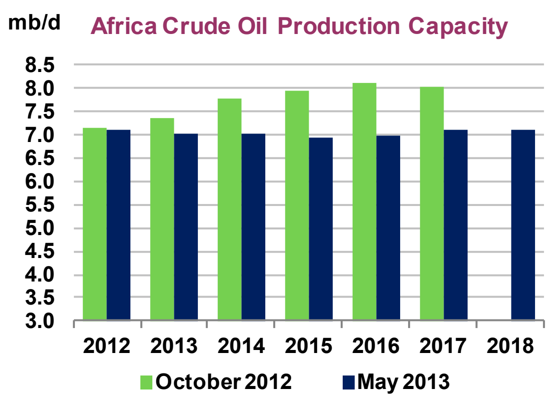
Iraqi production growth tempered by political and bureaucratic woes (continued)

The protracted north-south dispute has forced companies to delay development plans given the billions of dollars of investment at risk. We have slightly trimmed our forecast for the northern region to average 450 kb/d by 2018 versus the 500 kb/d expected earlier. A hardening of positions on both sides in recent months has meant the status quo of limited capacity growth has been factored into our forecast. A resolution to the protracted conflict, however, could lead to a much stronger increase in capacity at the tail end of the forecast given the resource base.

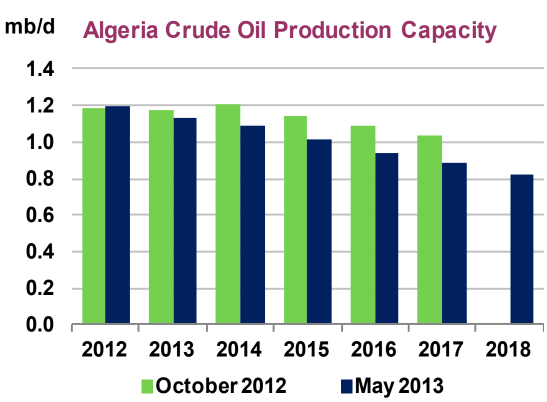
Security challenges for OPEC's African producers

OPEC's African members are struggling to expand production capacity given an array of political, security and contract issues. Nigeria, Angola, Libya and Algeria collectively post zero growth over the forecast period, to 7.12 mb/d. That is a steep 685 kb/d downward revision from the 2012 *MTOMR* outlook. Higher security risks in the region in the wake of the Arab Spring, uncompetitive fiscal terms, challenging local content requirements and contract sanctity concerns have all combined to derail the region's outlook for crude oil production capacity growth.

Increased violence by Islamist extremists and militants, against a backdrop of political instability across much of Northern and West Africa since the Arab Spring of 2011, is changing the equation for acceptable risks for international oil companies. The latter have a long experience in working in high-risk regions, but the deadly terrorist attack on Algeria's In Amenas gas facility in mid-January has prompted intensive reviews of how they operate in high-risk areas.

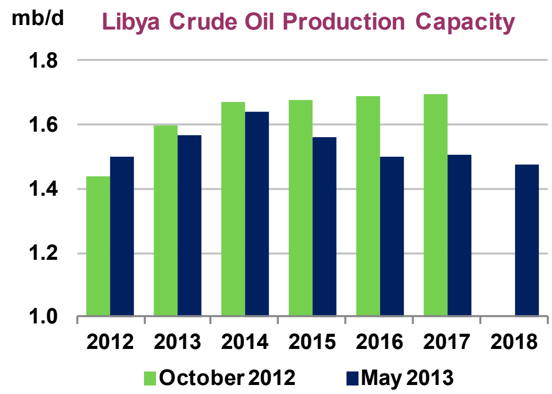


The escalating violence in North and West Africa may also alter investment plans in Algeria and Libya. One major concern is both Algeria and Libya's refusal to allow private security firms to protect oil projects. In Nigeria, resurgence in so-called 'bunkering' (oil theft) along pipelines and increased sectarian violence continue to destabilise the country. Equally important, however, is the country's inability to pass the long, drawn-out legislation affecting contract terms and reorganisation of the state oil company, which has effectively delayed final investment decisions by years.



Algeria's crude oil production capacity is forecast to decline by 380 kb/d to 815 kb/d by 2018. The country's production capacity outlook has long been constrained by relatively unattractive investment terms, corruption scandals and bureaucratic inertia. The unprecedented deadly terrorist attack on Algeria's In Amenas gas facility in mid-January has heightened security concerns, and prompted companies to review their investment plans. Algeria amended its hydrocarbon law with improved tax terms in September 2012 but the changes largely affect frontier and shale investment, leaving existing contract holders with poor investment terms. Costly project delays have already led to Shell divesting its interest in the country, and BP and Total have scaled back their involvement over the past few years. Algeria has since said it plans to review its fiscal terms, but changes near-term are unlikely to have a significant impact on the current forecast.

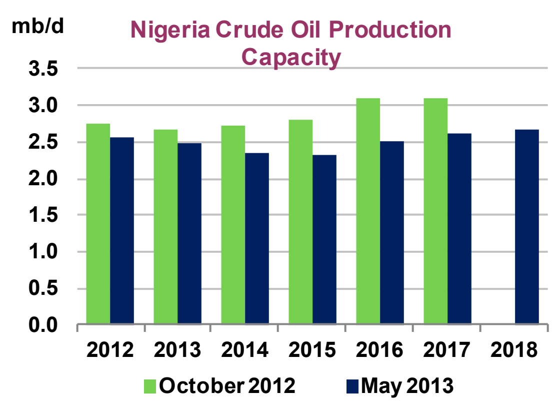
Libyan crude oil production capacity is largely unchanged in the medium term, projected to average around 1.54 mb/d for the five-year period. Production capacity is expected to rise to 1.64 mb/d in 2014 before slowly declining to 1.48 mb/d in 2018 due to the lack of new project developments. Libya announced a new bidding round will be held at end 2013. However, IOCs say security woes, relatively poor investment terms and lack of clarity on contract sanctity are issues remain to be addressed by the new government.



Indeed, the nascent political process has been fraught with problems due to a lack of central control as tribal groups and local militias continue to destabilise the country. Libya's rapid production recovery after the 2011 civil war was an impressive achievement but the country's ability to maintain or increase production capacity has been undermined by the insurgence of Islamist extremists in the region and lawlessness in general. IOCs and oil service companies, already mindful of the operational risks, sharply curtailed their presence following the deadly attack at the In Amenas facility in neighbouring Algeria. Oil service companies in particular are reluctant to resume operations in isolated desert areas of the country. Britain, Germany, the Netherlands and the US, among others, warned their nationals to leave the country in the wake of worsening security problems. Since then, staff have been slow to return in the current climate.

Libya set up a 15 000 strong special security force made up of former rebel fighters, the Petroleum Facilities Guard (PFG), to guard its oil installations, but infighting in the ranks has led to fears that the PFG are becoming part of the problem, not the solution. Libyan crude oil production fell to a seven-month low in January 2013, to just under 1.4 mb/d. The deterioration in the security situation has led to shut-ins in recent months, including the Mellitah gas complex, which processes crude from the Elephant and Wafa fields. In the medium term, security concerns are behind PT Medco Energi Internasional's decision in late March to delay by two years development of Area 47, a project originally slated to produce 50 kb/d starting in 2014.

Nigeria's production capacity has suffered from increased sectarian violence and damage to oil infrastructure by criminal gangs. Crucially, in 2013 Islamic extremists have stepped up attacks in the northern region of the country and carried out kidnappings of foreign workers in and around the capital, with oil industry staff increasingly targeted. After a long silence following an October 2009 cease-fire agreement, militant group Movement for



the Emancipation of the Niger Delta (MEND) resurfaced in April 2013 and threatened to carry out a "plague of attacks" following the sentencing of its former leader Henry Okah to 24 years in prison on terrorism charges.

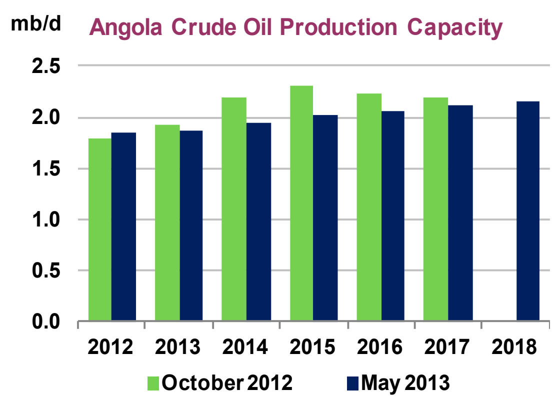
Nigerian capacity is forecast to rise by just 85 kb/d on a net basis over the forecast period, to 2.66 mb/d by 2018. That is a downward revision of just over 200 kb/d from last October's report. As in previous years Nigeria's production is far below its potential due to the long delay in passing the controversial 'Petroleum Industry Bill' (PIB) in the Legislature. Government announcements that an agreement is near have repeatedly failed to materialise, and currently there is no timeline for finalising the bill. The draft legislation enables the government to renegotiate old contracts and impose higher royalties and taxes. The IOCs argue new fiscal and tax terms are not competitive and undermine the viability of offshore oil and gas projects. Increased competition for market share among light, gasoline-rich crudes amid fast-rising US LTO production may help concentrate politicians' efforts to finalise the PIB soon, as IOCs weigh the market outlook for Nigerian grades. Our current forecast assumes the PIB will be adopted given financial imperatives. We have therefore included several projects that have still not been greenlighted but have a high probability of moving forward. Offshore, approximately ten new projects are slated to be brought online by 2018, with a total gross peak capacity addition of 1.12 mb/d. Notably, there is a lack of new project start-ups in 2013-14. Exceptionally, however, ENI has opted to fast-track its deep water Zabazaba and Etan discoveries, which are expected to add a further 120 kb/d of new capacity by 2015. Three projects are pencilled in for both 2016 and 2017. Indeed, final investment decisions for projects in 2018 and beyond are not expected until the new PIB is adopted.

Nigerian Project Developments

Planned	kb/d	Start-Up
Ofon 2	60	2012
Usan	165	2012
Erha North	75	2015
Zabazaba/Etan	120	2015
Bonga SW & Aparo	140	2016
Bonga NW	50	2016
Nsiko	100	2016
Egina	200	2017
Bosi	135	2017
Uge	110	2017
Total	**1155**	

Oil spill liabilities, chronic bunkering and damage to onshore and shallow water infrastructure have prompted Shell, ENI and Petrobras to divest their onshore operations, largely to Nigerian companies. Approximately 200 kb/d of shut-in capacity has been taken over by local companies, with roughly half the volumes expected to be redeveloped in the medium term.

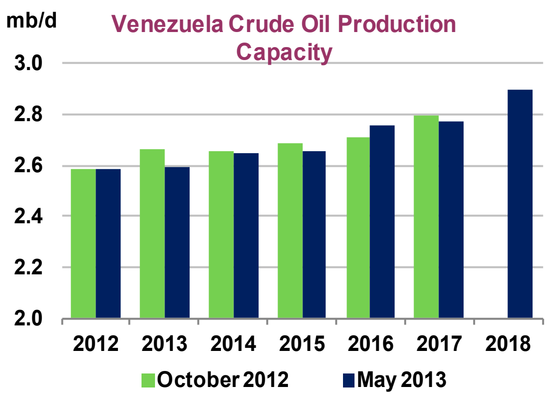
Angola's crude oil production capacity is forecast to rise 320 kb/d to 2.17 mb/d by 2018, a downward revision of around 125 kb/d since the 2012 *MTOMR* due to project delays related to local content requirements, equipment and staff shortages as well as protracted negotiations between state oil company Sonangol and joint-venture partners over project development plans. Despite the delays, Angola has some 15 deep water development projects on the books that are slated to add a gross 1.61 mb/d at peak levels over the 2013-18 period. The next projects due to come online are Total's 160 kb/d Block 17 CLOV development and BP's 150 kb/d Block 31 SE PAJ field in 2014.

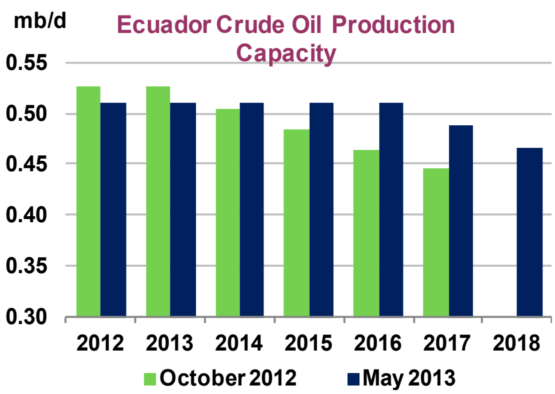


Venezuela production capacity on course to edge higher

Venezuela's new president Nicolas Maduro is expected to follow in his predecessor Hugo Chavez's footsteps and keep a tight rein on the country's oil sector. Production capacity is forecast to rise on a net basis by just over 300 kb/d, to 2.90 mb/d by 2018. President Maduro, however, inherits a state oil company, PDVSA, heavily in debt after the finances were used to fund massive social programmes leading up to last October's presidential election. The government's need for petrodollars, however, may force the new administration to take a more pragmatic approach to finances and increase investment in the country's heavy oil Orinoco projects. Major projects coming online during the forecast period are projected to add a gross 1.24 mb/d at peak production. 'Early production' from several Orinoco projects started in 2012 ahead of the October Presidential election though the small volumes were largely symbolic. Early production from the Junin-6 block PetroMiranda project with Russian partners Rosneft and Lukoil will be capped at 50 kb/d until an upgrader is completed post-2018. Also last year early production from the 200 kb/d PetroMacareo JV with PetroVietnam was brought on stream, with initial production capacity of 50 kb/d, building to 200 kb/d in 2015.

China's CNPC is expected to adopt a more aggressive production schedule given the billions of dollars it has committed as part of its oil-for-loan agreement with Venezuela. CNPC's 400 kb/d Junin Block 4 joint venture is expected online this year as is ENI's 240 kb/d Junin Block 5 project. However, financial constraints may slow the ramp up in all projects.



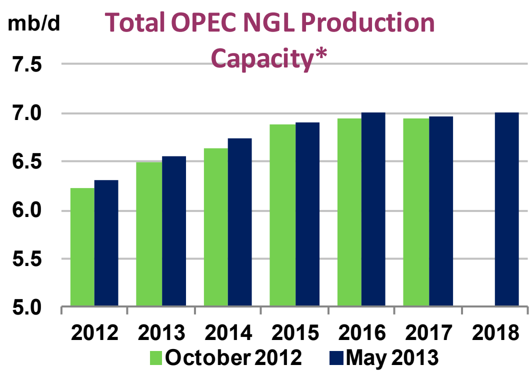


Marginal producer **Ecuador** is on track to see production decline over the next five years in line with previous expectations due to the country's recent wave of nationalising IOC assets. Production capacity is forecast to decline by 45 kb/d to 465 kb/d given the dearth of new development projects. Development of the heavy oil Pungarayacu has been delayed again, with new capacity of 50 kb/d now not expected until 2018.

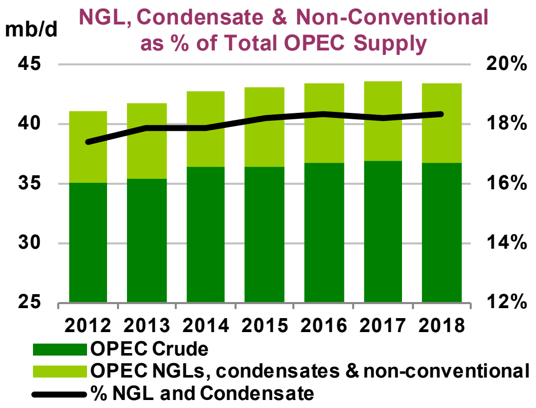
OPEC gas liquids supply

Production capacity of OPEC condensate and other natural gas liquids, and non-conventionals is forecast to rise by nearly 700 kb/d to 7.0 mb/d by 2018, largely unchanged from our October 2012 report. Saudi Arabia, the UAE, Qatar and Libya combined provide 80% of the incremental supply. Iranian capacity is marginally lower in the wake of sanctions.

The production ratio between condensates and NGLs remains steady at 44% and 56%, respectively. OPEC condensate capacity is projected to rise by around 420 kb/d to 2.95 mb/d while NGLs are forecast to rise by 250 kb/d to 3.78 mb/d by 2018. A ramp up of capacity at gas-to-liquids (GTLs) plants in Qatar is largely behind the 55 kb/d increase to 270 kb/d. Expansion of NGL capacity is fuelled by the need for increased natural gas supplies used to meet strong demand at utilities, water desalination plants and industry as well as for reinjection at ageing oil fields.

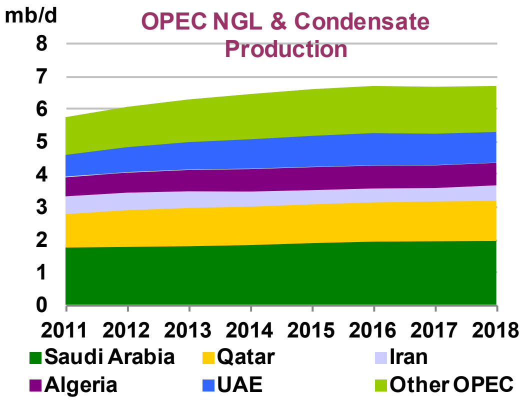


*includes condensates, natural gas liquids & Non-conventionals



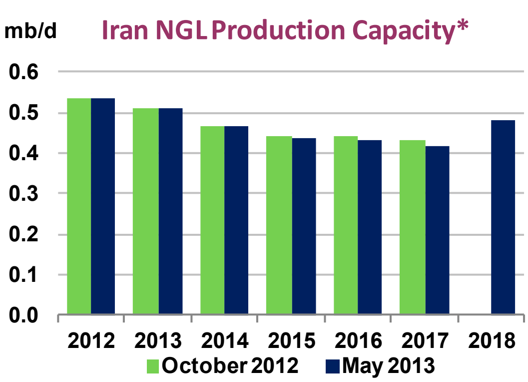
Saudi Arabia, with the largest capacity, sees production rise by 180 kb/d, to 1.98 mb/d by 2018. The two-phase development of Manifa field will add 65 kb/d of condensate production by 2014. The Hasbah project will add 40 kb/d of NGLs in 2013. Start-up of the massive 240 kb/d Shaybah NGL development, which includes 190 kb/d of ethane, is planned for late 2014/early 2015.

Qatar, OPEC's second largest holder of NGL capacity, sees condensate, natural gas liquids and non-conventional capacity increase by 100 kb/d to 1.23 mb/d by 2018. Qatar completed start-up of all its LNG trains in 2012. The last big project online is the RasGas USD 10.3 billion Barzan gas project, which will add 50 kb/d to condensate capacity. Project plans call for a two-stage start-up, with the first train on in mid-2014 and the second in 2015.



Start-up of the 120 kb/d Pearl GTL project in early 2012 raised total GTL capacity to 155 kb/d. (GTLs are reported as non-conventional oil supply rather than included in NGL estimates).

The **UAE's** NGL capacity is projected to rise by around 170 kb/d, to 965 kb/d by 2018. Start-up of the Integrated Gas Development (IGD) project in 2013 will boost capacity by 140 kb/d, with condensates pegged at 30 kb/d and NGLs at 110 kb/d. The Shah Sour Gas project is forecast to add 65 kb/d of condensate and other natural gas liquids in the second half 2015.



*includes condensates, natural gas liquids & Non-conventionals

Projections for **Iran's** NGL capacity have been revised down yet again amid all-encompassing US and European Union sanctions imposed on the country's oil and financial sectors in 2012-13. NGL capacity is forecast to decline by 55 kb/d to 480 kb/d over the 2013-18 period. Prior to implementation of more stringent sanctions in 2012, Iran's NGL capacity in 2011 was forecast to expand to 880 kb/d by 2015, double the level of the current forecast. Severe cash flow constraints have limited Iran's ability to procure the needed supplies, equipment and latest technology to maintain and expand infrastructure, especially for its planned South Pars developments. In the later half of the period, however, Iran is expected to push its gas development, with slightly more condensate expected.

Estimated OPEC Sustainable Condensate & NGL Production Capacity

(In thousand barrels per day)

	2012	2013	2014	2015	2016	2017	2018	2012-18
Algeria	596	636	669	686	681	675	671	*75*
Angola	70	93	130	135	140	140	140	*70*
Ecuador	1	1	0	0	0	0	0	*-1*
Iran	537	512	466	438	432	418	480	*-57*
Iraq	79	83	88	94	94	94	94	*15*
Kuwait	225	275	275	275	275	275	275	*50*
Libya	89	109	149	184	199	204	204	*115*
Nigeria	528	514	524	523	523	530	517	*-11*
Qatar	1 136	1 180	1 184	1 194	1 206	1 222	1 232	*96*
Saudi Arabia	1 795	1 816	1 851	1 910	1 955	1 965	1 975	*180*
UAE	797	870	931	977	1 016	990	967	*170*
Venezuela	235	225	210	210	205	187	170	*-65*
Total OPEC NGLs*	**6 088**	**6 315**	**6 478**	**6 627**	**6 725**	**6 701**	**6 726**	***638***
Non-Conventional**	**218**	**244**	**271**	**271**	**271**	**271**	**271**	***54***
Total OPEC	**6 306**	**6 558**	**6 749**	**6 898**	**6 997**	**6 972**	**6 997**	***691***

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

Biofuels

- **World biofuel production is expected to reach 2.36 mb/d in 2018**, an increase of 503 kb/d from 2012. Short-term downward revisions in the US, Argentina and OECD Europe, as well as increasing uncertainty over political support for biofuels, affect the medium-term outlook, trimming 28 kb/d from the 2017 estimate compared to the 2012 *MTOMR*.

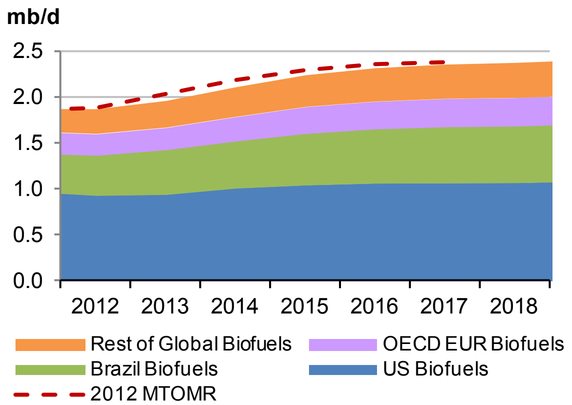
- **Biofuel output for 2013 is revised down by 80 kb/d** compared to our previous forecast, amid lower ethanol output in the US (-35 kb/d compared to the 2012 *MTOMR*) and weaker biodiesel output in OECD Europe (-15kb/d) and Argentina (-10 kb/d).

Weaker short-term outlook impacts medium-term projections

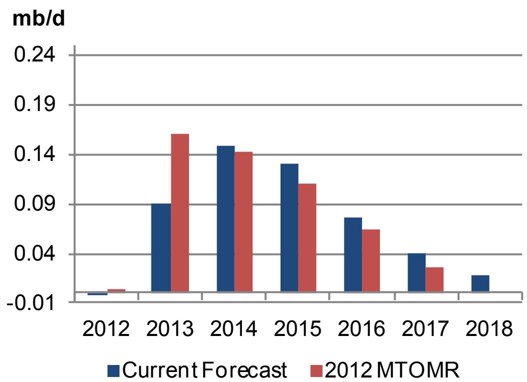
Global biofuels production stalled at 1.86 mb/d in 2012, 10 kb/d lower than expected in the 2012 *MTOMR*. Over the medium term, global output is projected to reach 2.34 mb/d in 2017, down 30 kb/d compared to the previous forecast, and 2.36 mb/d in 2018. In terms of volumes, ethanol remains the dominant biofuel, with global output reaching 1.83 mb/d in 2018, compared to 0.55 mb/d of biodiesel.

Global biofuel output for 2013 is expected to grow by 90 kb/d to 1.95 mb/d, reflecting a downward revision of 80 kb/d compared to our 2012 *MTOMR* projection. The biggest revision results from lower US ethanol supply (-35 kb/d compared to 2012 *MTOMR*), which we project to decline 10 kb/d mainly as a result of persistently high corn prices caused by last year's severe drought. The outlook for the biodiesel sector is more positive amid an enhanced blending mandate under the RFS2, and the re-introduction of the USD 1/gal blender's tax credit, driving a 20 kb/d year-on-year growth in production.

Global biofuels supply 2012-18



Global biofuels supply annual growth vs. previous forecast



In Brazil, the world's second-largest biofuel producer, ethanol production is continuing to rise and should reach 440 kb/d in 2013 (a 50 kb/d year-on-year increase), as good sugarcane supplies should lead to lower prices and enhance the economic attractiveness of ethanol over gasoline at the pump (see also March 2013 *OMR*). The re-increase in the domestic blending mandate from 20% to 25% as of 1 May will also stimulate enhanced use of ethanol. Over the medium term, we see Brazilian ethanol output rising to 540 kb/d in 2018, broadly in line with our previous forecast. Brazilian biodiesel output should stall at 50 kb/d (-10 kb/d compared to 2012 *MTOMR*) as the National Agency for Petroleum, Natural Gas and Biofuels (ANP) did not succeed in selling the full volumes offered at recent biodiesel auctions (517 million litres out of 715 million litres offered in March auction; 488 million litres out of 750 million litres in April auction; FO Lichts, 2013), undermining the prospects for this year's output. In light of sufficient production capacity, we expect output to continue to grow over the medium term with 2018 production at 80 kb/d.

For Argentina, we expect a 10 kb/d lower biodiesel production compared to the previous year (-13 kb/d compared to 2012 *MTOMR*) as ongoing anti-dumping investigations in the EU result in declining biodiesel exports to Europe. Since we expect that the drop in export demand cannot be compensated by the domestic market, even if recently announced plans to introduce a B10 mandate this summer materialise, we see 2017 production at 50 kb/d, down 20 kb/d compared to the 2012 *MTOMR*.

In OECD Europe we see 2013 biodiesel production reaching only 160 kb/d (-15 kb/d compared to previous forecast), amid continued negative margins and reduced physical demand caused by enhanced use of double-counted biodiesel.[3] While we currently see 2018 production at 205 kb/d, it is important to note that the future of the sector is uncertain in light of new EU legislation that might limit the contribution of conventional (first-generation) biofuels under the Renewable Energy Directive. OECD Europe's ethanol supply is projected to reach 80 kb/d in 2013, as capacity additions continue to drive growth in output. Over the medium term, we project steady growth in ethanol production with volumes reaching 100 kb/d in 2018, a forecast that is, however, subject to possible policy changes on EU level (see above).

[3] The EU Renewable Energy Directive states that the contribution of biofuels made from wastes, residues, non-food cellulosic material, and lingo-cellulosic material shall be counted twice towards the national targets for 2020. This has led to increasing volumes of biodiesel from used cooking oil and waste animal fats being marketed and reducing demand for conventional biodiesel produced from vegetable oil.

In China, the biggest producer of ethanol in Asia, we see 2013 ethanol production reaching 45 kb/d, in line with the 2012 *MTOMR*, compared to 35 kb/d in all other Non-OECD Asian countries combined. Blending mandates in several provinces continue to drive demand for ethanol, but government regulations preventing the use of food crops as feedstock in new production plants limit the medium-term growth potential in the Chinese ethanol sector. Over the medium-term, we see production increase from 40 kb/d in 2012 to 55 kb/d in 2018. Biodiesel currently plays only a minor role in China and stood at 5 kb/d in 2012, with output projected to reach 10 kb/d by 2018. Asian biodiesel production excluding China is seen at 60 kb/d in 2013, and should grow to 80 kb/d in 2018, in line with our previous forecast. As sustainability requirements in the EU, as well as ongoing anti-dumping investigations limit the export potential for palm-oil biodiesel from these regions, domestic demand will be vital for the domestic biodiesel industry.

In the advanced biofuel sector, we expect global production capacity to reach 160 kb/d in 2017, up from 80 kb/d in 2012, but 20 kb/d less than projected in the 2012 *MTOMR*. A couple of commercial-scale production units have come online in the US and Europe, with other projects scheduled to start within the next year. Additional access to funding, for instance under the EU's NER300 program, has provided the required financial backing for additional projects in Europe that are now likely to come online over the next years.

On the downside, a number of companies, including oil majors, have stepped back from their projects for various reasons. Greater-than-expected technological challenges were among the most important reasons for the cancellation of projects. Additionally some commercial-scale projects were delayed or abandoned as a result of difficulties in ensuring the required financing. Overall, the political framework for advanced biofuels in many countries seems to be insufficient to fully address the investment risks associated with first-of-their-kind commercial-scale production plants.

World biofuels production, 2012-18

kb/d	2012	2013	2014	2015	2016	2017	2018
OECD Americas	959	974	1 043	1 080	1 097	1 097	1 094
United States	927	937	1 005	1 039	1 058	1 061	1 063
OECD Europe	230	239	262	288	297	304	306
OECD Asia Oceania	15	17	20	20	22	22	23
Total OECD	**1 205**	**1 230**	**1 324**	**1 389**	**1 416**	**1 423**	**1 423**
Non-OECD Europe	8	8	8	8	8	8	9
China	45	51	58	59	62	62	63
Other Asia	87	96	106	113	118	129	133
Latin America	511	558	594	647	686	706	717
Brazil	433	483	509	557	587	606	612
Middle East	0	0	0	0	0	0	0
Africa	4	6	8	12	14	15	16
Total Non-OECD	**654**	**719**	**773**	**839**	**888**	**920**	**939**
Total World	**1 859**	**1 949**	**2 098**	**2 228**	**2 304**	**2 343**	**2 362**
World - Revision vs 2012 *MTOMR*	-11	-81	-74	-55	-42	-28	

Policy uncertainty is increasingly clouding the medium-term outlook for biofuels. In several key markets, looming policy changes might undermine vital support for biofuels. In the EU, a proposal launched by the European Commission in October 2012 suggests limiting the use of food-based biofuels to 5% of energy demand in the transport sector (roughly the current average blending share in the EU) instead of a maximum 10% as currently stipulated in the Renewable Energy Directive. Although discussions on the proposal are still ongoing, the proposal has severely affected the industry's confidence with likely negative implications for future investments in the sector.

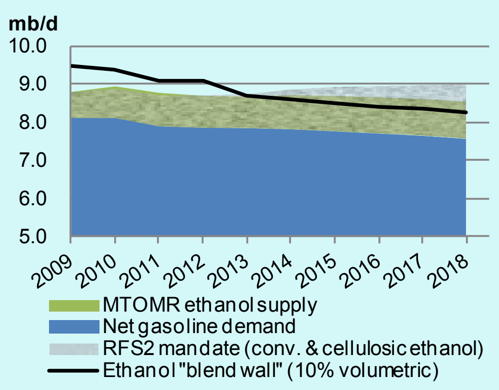
Other recent EU policy measures are having a global effect that extends far beyond the EU itself. In February 2013, the European Commission, following a 15-month anti-dumping investigation, imposed a 9.5% anti-subsidy duty on US ethanol. Biodiesel imports from Argentina and Indonesia to the EU are currently also the subject of an anti-dumping investigation. As of November 2012, all imports from these two countries need to be registered, and might become subject to anti-dumping duties that could be introduced retroactively once the investigation is concluded. The ongoing investigation has already encouraged a reduction in EU biodiesel imports from Argentina, and is the main reason for the downward revision of our medium-term production forecast for that country.

The policy framework for biofuels in the US has also come under scrutiny, as a public debate on the *raison d'etre* of the Renewable Fuels Standard 2 - the principal support policy for biofuels - is gaining momentum (see feature box below).

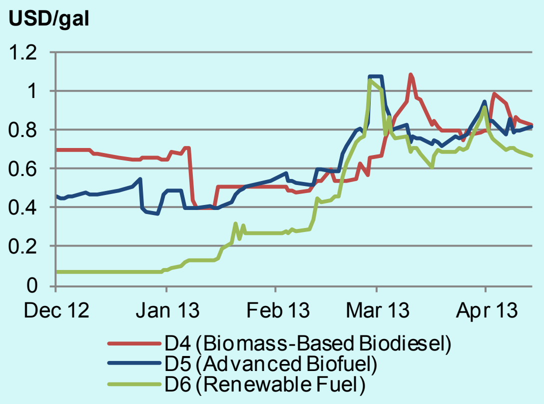
"Blend wall" clouds US medium-term outlook

Both the economics and policy environment surrounding the US ethanol sector have become more complicated since the 2012 *MTOMR*. In 2012, US ethanol production declined for the first time since ethanol became a widely used blending component, falling 4.6% year-on-year to 864 kb/d. The decline came as last year's severe drought supported high corn prices and reduced crushing margins, leading many producers to temporarily stop production in the last months of the year. With 10% of the around 200 ethanol plants in the US still temporarily idle, and 1Q13 ethanol production averaging 797 kb/d according to EIA data (vs. 914 kb/d a year earlier), we see 2013 output at 850 kb/d, down 10 kb/d year-on-year.

US gasoline demand vs. projected ethanol production and mandated ethanol use



Development of RIN prices between December 2012 and April 2013



Sources: EIA, USDA, Bloomberg LP.

Note: RIN = renewable identification numbers; RFS2 mandate does not include ethanol potentially blended to meet the "advanced biofuel" mandate.

"Blend wall" clouds US medium-term outlook (continued)

The impact of high corn prices should be mitigated through the new harvest in autumn – forecasted by USDA at 370 Mt – and support an increase in ethanol production in 2014 to 920 kb/d. Over the medium-term, ethanol output is expected to reach 979 kb/d in 2018, on average a 10 kb/d weaker medium-term growth than projected in the 2012 *MTOMR*. However, there are a number of downside risks that could undermine the medium-term outlook for ethanol.

Last year's severe drought led to increasing public opposition towards the RFS2 – the principal policy instrument to promote biofuel production and use in the US – mainly from livestock farmers that saw their margins disappear as a result of the high corn prices. Since the beginning of the year, the efficacy of the RFS2 has been called into question as market participants claim to have great difficulties surpassing the ethanol "blend wall", which represents approximately a 10% share of ethanol in the gasoline pool (about 870 kb/d based on 2012 gasoline consumption).

The blending mandate under RFS2 is 16.55 billion gallons (1 080 kb/d, of which 83 kb/d is biomass-based biodiesel) in 2013, and is set to more than double by 2022. With declining US gasoline demand - mainly as a result of enhanced fuel efficiency stipulated by the Corporate Average Fuel Economy (CAFE) Standards - the volume of ethanol that can be blended before reaching the "blend wall" is set to shrink over the medium-term. The need to raise the share of ethanol in the US gasoline pool beyond 10% is thus apparent. However, several parties, from gasoline retailers to automobile manufacturers, have flagged liability issues associated with using blends higher than E10. Additionally, the extra costs and logistical challenges of reconfiguring pumps and storage at fuel stations pose barriers to overcoming the "blend wall".

One option for blenders to avoid raising the physical share of ethanol in gasoline is through the use of renewable identification numbers (RINs).[4] Prices for RINs skyrocketed in March 2013 to USD 1.05 up from a few cents some weeks earlier and prices are currently still well above those at the beginning of 2013. Barring a rebound in gasoline demand, however, many factors suggest that the RIN market will remain tight in the future due to the growing discrepancy between mandated volumes under RFS2 and the actual levels of ethanol blending that can be achieved under current and forecasted market conditions. This holds particularly true for the cellulosic-ethanol mandate that was revised downward by the EPA from the original 1 billion gallons to 0.014 billion gallons (1 kb/d) in 2013, but still appears ambitious in light of only two operating commercial-scale production units. Looking forward, further revisions of the cellulosic-ethanol quota are likely, given that the size of the industry is far too small in order to provide the 16 billion gallons in 2022 currently mandated under the RFS 2.

Higher RIN prices for "renewable fuel" should improve the competitiveness of E85 compared to E10 and lead to a higher share of this fuel in the market, which could be absorbed by the 10.7 million flex-fuel vehicles in the US EIA. In addition the high price for D6 RINs could trigger blending of biodiesel within the "advanced biofuels" mandate, both of which could take some of the pressure off the RIN market. Nonetheless, the political debate seems likely to continue, as are calls on the EPA to revise the RFS2 mandate. Though there is no clear indication the RFS2 will be amended, growing market perception of policy uncertainty introduces an additional downside risk to our medium-term forecast.

[4] The U.S. Environmental Protection Agency uses Renewable Identification Numbers to track renewable transportation fuels and monitor compliance with the Renewable Fuel Standard. The RIN is attached to the physical gallon of renewable fuel as it is transferred to a fuel blender. After blending, RINs are separated from the blended gallon and are used by obligated parties (blenders, refiners, or importers) as proof that they have sold renewable fuels to meet their RFS mandated volumes. RINs may be used to satisfy volume requirements for the current year or up to 20% of the following year's required RFS volumes. Obligated parties may also sell RINs amongst each other, with prices being determined by market factors.

REFINING

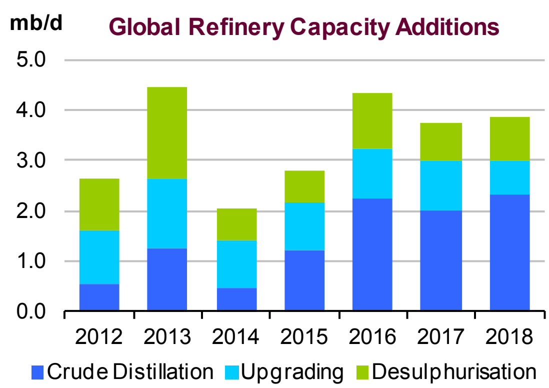
Summary

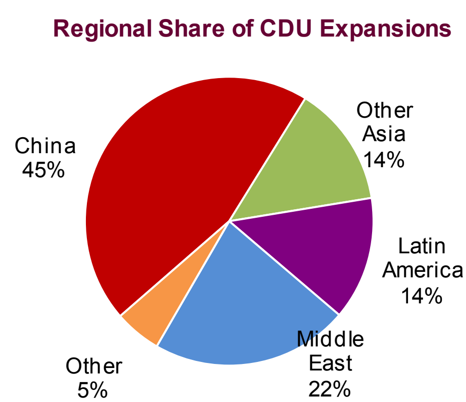
- **Global refinery crude distillation capacity is set to rise by 9.5 mb/d** from 2013 to 2018, with Asia accounting for about 60% of the increase and the Middle East 22%.

- **Total world refining capacity will reach 106.7 mb/d by the end of 2018**, of which 60% will be in non-OECD countries. OECD Europe and Pacific will see their capacity reduced as refiners increase their competitive position mainly through consolidation and restructuring.

- **Strong demand for middle distillates pushes investment in deep conversion facilities** and hydroprocessing with upgrading capacity increases exceeding refining capacity growth.

- **The US refining sector is restructuring to benefit both its light domestic crude oil slate and imported heavy crude oils.** As domestic demand remains subdued, distillate export markets to Latin America and Europe are the key to profitability.



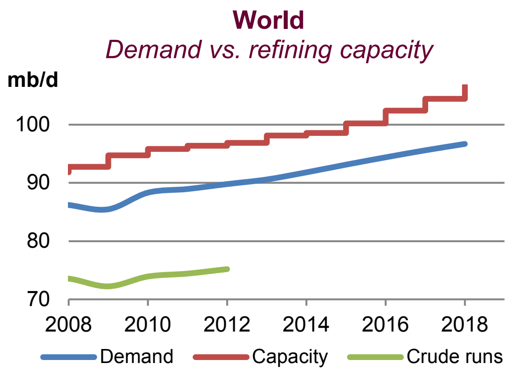


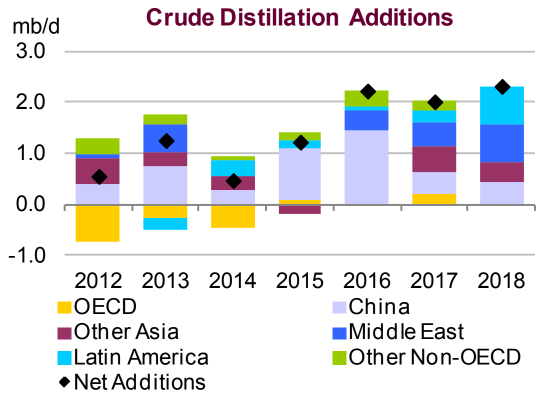
Refining investment: paradigm change

By the end of 2012, total refinery crude distillation capacity reached 96.9 mb/d and capacity utilisation rate was 78%, with crude throughput averaging 75.2 mb/d and total demand 89.8 mb/d. Global refinery expansion plans for the next five years will add 9.5 mb/d of crude oil distillation capacity. China and other Asian countries will drive the growth with 5.6 mb/d of additional capacity expected, followed by the Middle East which will see capacity increase by more than 2.1 mb/d to 10.5 mb/d.

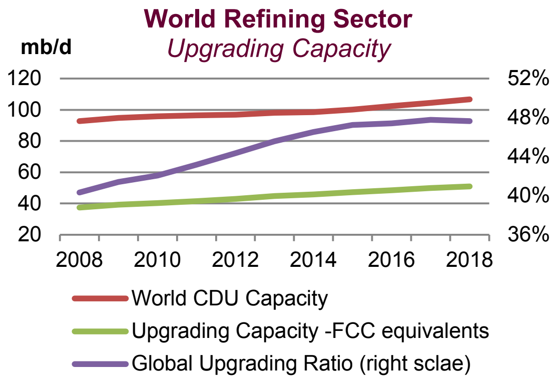
As capacity additions are forecast to increase faster than world demand, the persistence of excess refining capacity is expected to weigh on refining margins, severely affecting the less efficient and oldest refineries in the world. The overall upgrading ratio gradually increases from 44% in 2012 to 47% in 2018 as new refineries focus mainly on heavy crude oil processing, mostly from the Middle East and Latin America.

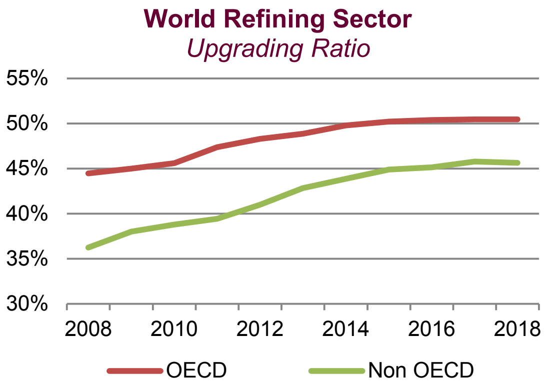
Behind these massive development plans in Asia and the Middle East stand two very different approaches in terms of strategy and marketing plans. Capacity development in Asia reflects the aggressive expansion required to keep pace with the rapid growth in demand while Middle East refiners, mostly in joint venture with OECD refiners or Chinese companies, are clearly targeting export markets.





Facing weak demand growth and tighter regulations, OECD refiners have no choice but to increase their competitiveness through restructuring and consolidation. Since 2008, 15 refineries were shut in Europe with a total capacity of 1.7 mb/d and more refining closures are expected in the coming years. Japanese refiners will close a total of around 800 kb/d by 2014, in line with government regulations aimed at increasing conversion yields. But this may lead to even more closures in the long run as these refiners will unlikely be able to justify investment in upgrading all of their refineries under the current business environment, a stagnant economic outlook and Chinese and Other Asian refiners competition. However, recent developments in Southern Europe (Spain, Portugal) show that investment in deep conversion units may finally be a profitable alternative to refinery closures.





The OECD Americas refining sector is currently completely restructuring, with each regional district trying to optimise its crude slate between light domestic crude oil and heavy imported oil. High sustained margins and the outlook for continued growth pushes US refiners to invest both in deep conversion but also in light oil processing.

World Refinery Capacity Additions (thousand barrels per day)

Capacity[1]	2013	2014	2015	2016	2017	2018	Total
OECD	**-281**	**-470**	**75**		**214**		**-462**
OECD Americas	*105*	*29*	*75*				*209*
OECD Europe	*-326*				*214*		*-112*
OECD Pacific	*-60*	*-499*					*-559*
Non-OECD[4]	**1 537**	**941**	**1 150**	**2 226**	**1 800**	**2 316**	**9 970**
FSU	*162*	*48*	*160*	*215*			*585*
Non-OECD Europe							
China	*730*	*270*	*1 000*	*1 460*	*400*	*440*	*4 300*
Other Asia	*300*	*272*	*-185*		*525*	*380*	*1 292*
Latin America	*-226*	*285*	*175*	*98*	*215*	*765*	*1 312*
Middle East	*531*	*20*		*358*	*465*	*731*	*2 105*
Africa	*40*	*46*		*95*	*195*		*376*
Total	**1 257**	**471**	**1 225**	**2 226**	**2 014**	**2 316**	**9 508**

Upgrading[2]	2013	2014	2015	2016	2017	2018	Total
OECD	**38**	**175**	**179**	**80**	**106**		**578**
OECD Americas	*60*	*221*	*64*				*345*
OECD Europe	*-40*		*115*		*106*		*181*
OECD Pacific	*18*	*-46*		*80*			*52*
Non-OECD	**1 342**	**758**	**778**	**907**	**865**	**697**	**5 345**
FSU	*195*	*154*	*183*	*150*	*90*	*95*	*866*
Non-OECD Europe		*75*	*134*				*209*
China	*462*	*112*	*231*	*642*		*90*	*1 537*
Other Asia	*317*	*161*	*20*		*180*	*31*	*709*
Latin America	*-26*	*60*	*170*	*20*	*247*	*260*	*731*
Middle East	*394*	*196*	*40*	*95*	*241*	*221*	*1 187*
Africa					*107*		*107*
Total	**1 380**	**932**	**957**	**987**	**971**	**697**	**5 923**

Desulphurisation[3]	2013	2014	2015	2016	2017	2018	Total
OECD	**-49**	**4**	**95**		**114**		**164**
OECD Americas	*240*	*85*	*60*				*385*
OECD Europe	*-200*		*35*		*114*		*-51*
OECD Pacific	*-89*	*-82*					*-170*
Non-OECD	**1 848**	**626**	**503**	**1 106**	**658**	**865**	**5 606**
FSU	*114*	*160*	*50*	*35*			*359*
Non-OECD Europe		*45*	*20*				*65*
China	*799*	*139*	*331*	*850*		*164*	*2 283*
Other Asia	*284*	*104*	*-98*		*284*	*10*	*583*
Latin America	*90*	*111*	*160*		*70*	*245*	*676*
Middle East	*466*	*30*	*40*	*222*	*262*	*446*	*1 465*
Africa	*95*	*37*			*42*		*174*
Total	**1 799**	**630**	**598**	**1 106**	**772**	**865**	**5 769**

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.

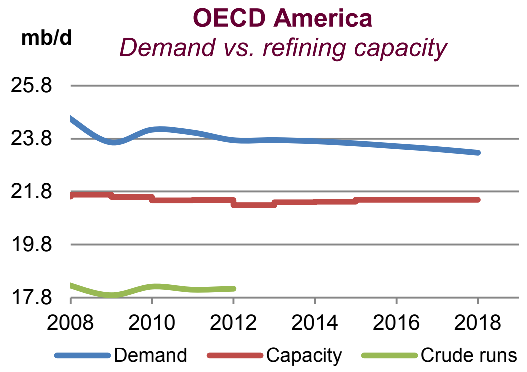
3. Comprises additions to hydrotreating and hydrodesulphurisation capacity.

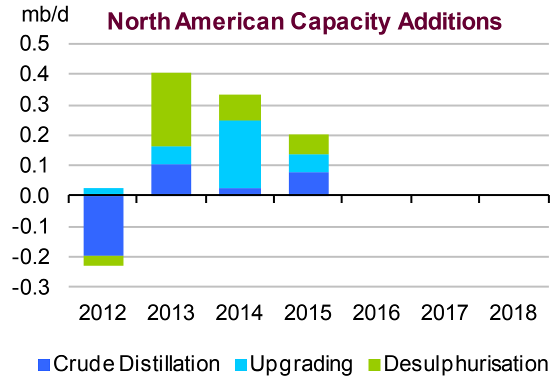
4. New OECD members Chile and Israel are still accounted for in Latin America and Middle East, respectively. Estonia and Slovenia have no refineries.

Regional developments

North America: a diversity of strategy

Refinery crude oil distillation capacity in **North America** is currently 21.29 mb/d. In 2012, average crude runs were 18.1 mb/d, with the region typically running at high capacity utilisation rates close to 85%.





OECD Americas Refining Capacity

mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	21.29	21.39	21.42	21.49	21.49	21.49	21.49
Upgrading ratio (%)	*63%*	*63%*	*64%*	*64%*	*64%*	*64%*	*64%*
Light Oil Processing							
Reforming	4.43	4.43	4.43	4.43	4.43	4.43	4.43
Isomerisation	0.81	0.81	0.81	0.81	0.81	0.81	0.81
Alkylation	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Bottom of the Barrel Processing							
FCC/RFCC	6.59	6.61	6.63	6.65	6.65	6.65	6.65
Hydrocracking	2.36	2.36	2.43	2.43	2.43	2.43	2.43
Coking	3.01	3.05	3.18	3.23	3.23	3.23	3.23
Thermal Crack/VBU	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Hydroprocessing	16.96	17.20	17.29	17.35	17.35	17.35	17.35

Note: Upgrading ratio defined as the ratio of upgrading capacity (FCC equivalent) to crude distillation capacity

Refineries in North America are considerably more complex than in other areas of the world, with an upgrading ratio of 63% in 2013 and on course to reach 64% in 2018. This higher conversion capacity is consistent with the area's strong demand for light transportation fuels, low residual fuel demand and a still-heavy crude slate. The expansion of North America's refining sector is currently driven by two extreme factors, with the development of heavy Canadian oil sands on one side and booming US production of light tight crude and condensate on the other. Although crude distillation unit capacity increases remain limited, many projects involve large heavy oil conversion and hydroprocessing units. Additionally, the increase in the supply of NGL, resulting from the development of new rich gas plays in the US, such as Eagle Ford, will require new fractionation capacities.

US crude oil distillation capacity at the end of 2012 was 17.65 mb/d, up by 125 kb/d from 2011 on new capacities installed (370 kb/d) and units shutdown (245 kb/d). The main contributor to the increase was the new 325 kb/d crude distillation unit at Motiva's Port Arthur plant, although the unit was put into operation only recently, as serious mechanical failures delayed its start-up. One refinery was closed in 2012, Sunoco's 175 kb/d Marcus Hook, and more recently, Hess closed its small FCC refinery at Port Reading in PADD 1. In 2018, we estimate total US crude distillation capacity will reach 17.8 mb/d on expansion projects, mainly at ConocoPhillips' Borger (+50 kb/d), Valero's Sunray (+25 kb/d), Western Refining's El Paso (+25 kb/d) and BP's Whiting (+20 kb/d).

This expansion plan does not take into account new fractionation capacity associated with the development of new rich gas plays in West Texas, North Texas, Oklahoma, Marcellus and the Rockies. New fractionation capacity is needed with the increase in the supply of mix NGL. A total of 72 kb/d of local fractionation capacity is being added by 2013 to serve Eagle Ford producers (Copano, Southcross and Formosa). Operators in Mont Belvieu (Enterprise, Gulf Coast Fractionators, Cedar Bayou, Mont Belvieu and Lone Star NGL) have announced projects totalling 380 kb/d to be operational by end-2013. These capacity expansions will serve not only Eagle Ford producers, but will process raw mix NGL supplied from other regions as well. Similarly, Phillips 66 has recently announced that it is pursuing development of 100 kb/d NGL fractionators to be located in Old Ocean, Texas, close to the company's Sweeny Refinery.

The US refining sector is becoming increasingly differentiated regionally, with strong distortions between refiners in terms of strategies, crude quality, market and infrastructure.

PADD 1 (East Coast) refineries are in complete consolidation and restructuring mode, but the prospects for the medium term look better as they expand rail unloading terminals, allowing them more access to competitively priced Bakken crude.

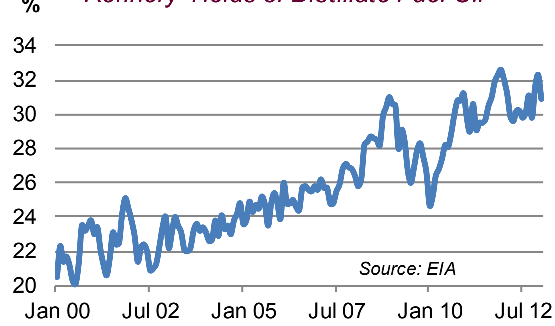
From 15 refineries operating in 2007, only 11 were still operable in 2012. With 7% of total US refining capacity and a low capacity utilisation rate in 2012 of around 79%, this region is characterised by structurally low refining margins as it relies still mostly on oil imports priced to Brent crude and limited access to cheap domestic crude oil and natural gas supply. Unfavourable economics have resulted in the idling or permanent closing of refineries (Eagle Point, New Jersey; Yorktown, Virginia; Delaware City, Delaware; Trainer, Pennsylvania; Marcus Hook, Pennsylvania; and Port Reading, New Jersey). Delaware City and Trainer have since been reopened under new ownership. PADD 1 refiners are trying now to increase the share of cheap local crude and natural gas in their feedstock to improve their operating margins. Although transportation cost (by rail) between the Midwest shale plays and the East coast is still between USD 12/bbl and USD 16/bbl, domestic crude remains competitive with imported Brent-price crude oils and expectations of lower transportation costs are optimistic as infrastructure and the volumes transported increase. Some Eastern refiners are already bringing in by rail light crude oil or investing in rail terminals to receive Bakken crude, like Delta Airlines' 185 kb/d Trainer, Philips 66's 238 kb/d Bayway, PBF's 180 kb/d Delaware, PES's 330 kb/d Philadelphia refineries, *etc*. Sonoco's 178 kb/d Marcus Hook facility, which has been permanently closed, has been converted in late 2012 into a facility to process NGL's from the nearby Marcellus Shale formation.

As of 2012, there were 27 refineries in **PADD 2 (Midwest)**, with a total capacity of 3.7 mb/d. These refineries have been enjoying exceptionally good margins, as the price differential between WTI and

Brent reached record high levels over USD 20/bbl in 2012. Major projects in this region have been oriented towards boosting heavy crude oil processing capacity for Canadian tar sand crude oil. By the end of 2012, Marathon's Detroit facility had added a new 28 kb/d coker unit and increased crude oil distillation capacity by 15 kb/d, while BP's Whiting 102 kb/d coker (the second largest delayed coker in the world) is expected in mid 2014. The district will also be the place for a new refinery, the first to be built in the US, since 1976. The 20 kb/d Dakota Prairie Refinery project is a joint venture between MDU Resources Group Inc. and Calumet Specialty Products Partners LP and is slated for completion in late 2014. At least three other refineries of similar size could be built in the region.

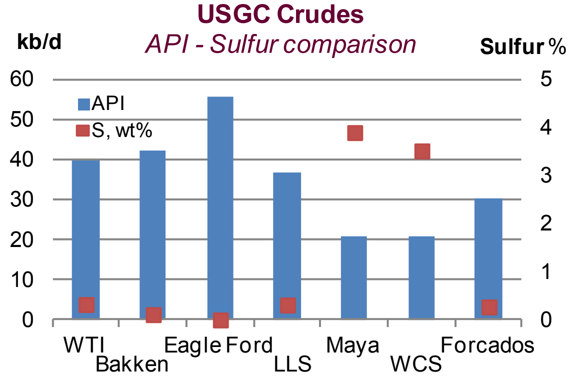
PADD 3 (Gulf Coast) is the dominant area in terms of refining for the US. Around 90% of PADD 3 capacity is located in Texas and Louisiana, with 2012 figures reporting 57 refineries operating in the region, and a capacity of 8.7 mb/d. These refineries are mostly oriented towards the production of diesel for the export market mainly to Latin America and Europe. Refiners have been recently investing in deep conversion units but also in hydrocracking units, boosting their production of diesel with distillate fuel oil yields reaching 32% at the end of 2012. By the end of 2012, USGC hydrocracking capacity surpassed 1 mb/d with the addition of new capacities at Valero's St Charles and Port Arthur refineries and Motiva's Port Arthur refinery. Beyond 2013, the region will continue to add hydrocracking capacity, with Marathon expected to complete the second of a 20 kb/d expansion and Valero expanding both the hydrocracker capacity at its Meraux refinery and adding other capacity at its Port Arthur and St Charles units.

Gulf Coast (PADD 3)
Refinery Yields of Distillate Fuel Oil

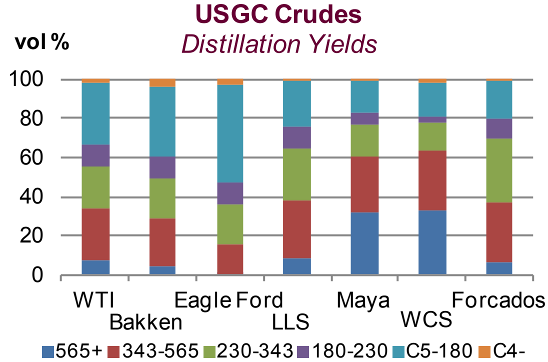


Although processing largely heavy and medium heavy crudes, Gulf Coast refiners are progressively receiving additional volumes of lighter and sweeter crude oil, mainly from the Eagle Ford shale play in West Texas. Until recently, there was a restricted pipeline capacity for transporting unconventional crude oil to the US Gulf Coast and only limited volumes were getting to the Houston area via rail. However, this flow of unconventional crude oil started to increase in mid-2012 with the Seaway reversal and its extension to 400 kb/d, in early 2013. With additional pipeline capacities, including Keystone XL, Permian pipelines, the twin Seaway, it is estimated that total pipeline inflow capacity will rise from 1 mb/d in 2012 to 3.5 mb/d in 2015.

USGC Crudes
API - Sulfur comparison

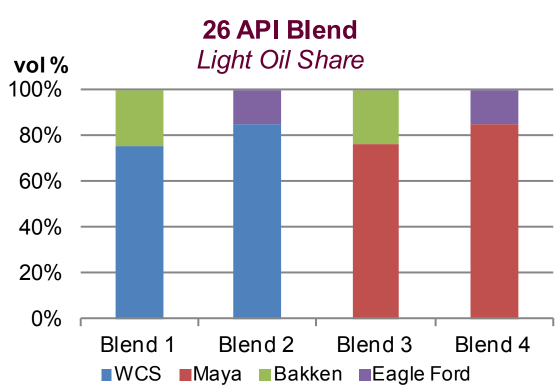


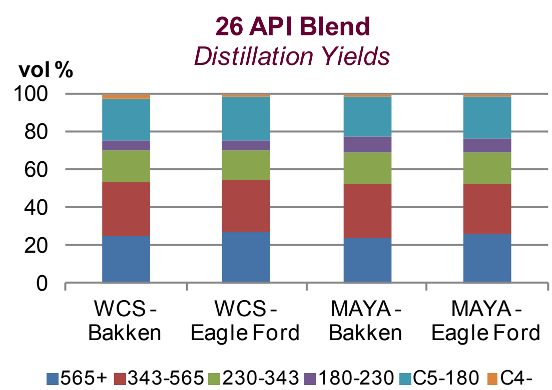
USGC Crudes
Distillation Yields



Of the different unconventional crude oils, which will flow to PADD 3, Eagle Ford poses a special challenge to Gulf Coast refiners. Eagle Ford API is in the range of 42 to 60 API with a typical figure of 55.6 API, much higher than all the other crudes processed in the region. In addition to its API and sulphur characteristics, distillation yields clearly show that Eagle Ford's heavy fractions (565+) are minimal (0.4%) and more than 53% of its constituents are in the light ends-naphtha range.

Faced with massive imports of light crude oil, refiners have several different options: a) replace any light crude that is currently imported; b) target a crude blend, mixing light tight oil with heavy crudes to produce a blend suitable for the refinery; c) modify existing assets or add additional investment to handle the lighter crude. The solution is typically refinery specific and, in the end, will be based on relative crude prices and economics. To make a 26 API blend with heavy WCS or Maya crude it takes about 25% of Bakken and 15% of Eagle Ford. The resulting blend is, however, an atypical crude with a lower middle distillate range and both higher light ends and heavy fractions. Processing this kind of crude produces less diesel, jet fuel than equivalent API crude oil, impacting refining margins.





Other refiners, like Valero and Flint Hills have started to reconfigure their refineries in order to process more Eagle Ford and unconventional crude oils. Valero is building a 90 kb/d crude oil topping unit at its Houston refinery to refine very light sweet crudes, including crudes from the South Texas Eagle Ford play. The project is scheduled to be completed in the first half of 2015. Valero is also upgrading its 90 kb/d Three Rivers refinery like Flint Hills Resources, who is upgrading its West Refinery in Corpus Christi with a view to process more Eagle Ford crude. Currently, only 50% of the crude processed at the 230 kb/d West refinery is sourced from Eagle Ford.

The **PADD 4 (Rocky Mountain)** district tends to have fewer and smaller refineries than elsewhere in the US, with 17 facilities in the region, and total capacity of 623 kb/d in 2012. These refiners have been reaping the rewards of cheap feedstock from the Bakken, Niobrara, and Utica shale plays as well as Canada, due to infrastructure bottlenecks in the US mid-continent. PADD 4 facilities have among the highest refining margins in the US.

PADD 5 (West Coast) has 32 refineries and a capacity of 3.1 mb/d. Most of the refineries are in California. The regional fuel market was severely disrupted in late 2012 until last April, following a massive explosion last summer at Chevron's 245 kb/d Richmond facility. Over the last decade, PADD 5 refiners have invested in order to process heavier crude oil, including Californian crude, Alaska North Slope, Canadian tar sands and Latin American crude oil. Refiners in this district have also started to optimise their crude slate, taking advantage of low domestic crude prices. As rail terminal infrastructure is taking longer to develop than in other states, because of more complex permitting, marine terminals are developing faster, as West Coast refineries are a good alternative for Western Canadian heavy crude when flows to US Gulf Coast remain constrained.

Canada refinery crude oil distillation capacity was 1.9 mb/d in 2012 and the country was running at high capacity utilisation rates close to 90%. Currently, the country focuses mainly on infrastructure projects to move land–locked Alberta crude oil eastwards or westwards as the US government has delayed approval of TransCanada's Keystone XL pipeline that would ship crude from Alberta oil sands to Texas. Two major projects are currently under study and waiting approval: a) the Energy East Pipeline project, a 4 400 km pipeline that will carry between 500 kb/d and 850 kb/d of crude oil from Alberta and Saskatchewan to refineries in Eastern Canada. Part of this pipeline includes the conversion of an existing natural gas pipeline; b) The TransMountain expansion project, would almost parallel the existing 1 150 km Trans Mountain pipeline route from Edmonton, Alberta to Burnaby, in British Columbia on the West Coast. The project would increase the pipeline capacity from 300 kb/d to 890 kb/d.

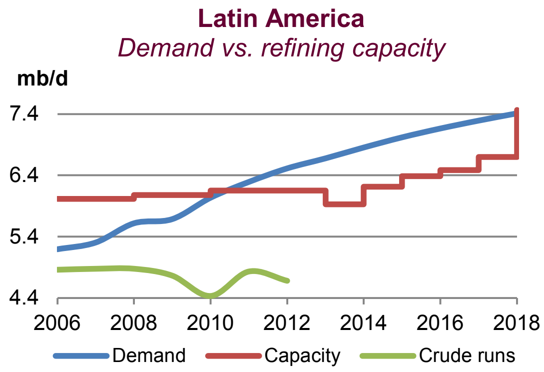
New refinery projects are also under study. Our forecast includes already the 50 kb/d Phase 1 of the Sturgeon refinery in Alberta in 2015. This project, leaded by North West Redwater Partnership (NWR), a partnership between North West Upgrading Inc. (NWU) and Canadian Natural Upgrading Limited (CNUL), is being built in three phases of 50 kb/d each. The project includes a CO_2 capture plant, as CO_2 will be used for enhanced oil recovery. Another project, but still to be approved, is the up to 550 kb/d Kitimat refinery project, sponsored by newspaper magnate David Black. In late April, a memorandum of understanding was signed with the Industrial and Commercial Bank of China, China’s largest bank.

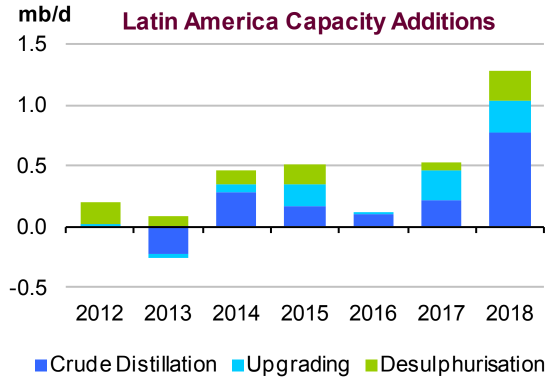
Lack of investment and regulatory issues impeding PEMEX to partner with foreign investors in the refining business, have left **Mexican** refineries unable to satisfy local demand both in volume and in quality. The Pemex’s 2013-17 business plan includes a modernisation/expansion project in Salamanca, and a new 250 to 300 kb/d refinery in Tula, but we do not expect completion of this project before 2018.

Latin America: an end to structural deficit

In 2012, **Latin American** crude oil distillation capacity was 6.15 mb/d. With an average crude throughput of 4.7 mb/d, the capacity utilisation rate in 2012 was 76% as some major refineries in the region have experienced recently some severe technical issues like in Venezuela, following a major accident at the 955 kb/d Paraguana refinery complex or in Brazil due to bad weather.

More than in other regions, Latin America faces increasing pressure for heavy oil conversion capacity as the domestic crude oil processed is typically heavy and sulphurous. The region’s conversion capacity is relatively high, which is consistent with its production of heavy crude oil. The upgrading ratio represents 40% of crude oil capacity and should reach 47% in 2018. The region will remain in refining capacity deficit over the whole forecast, securing a profitable export market to USGC refiners. By the end of 2018, several projects, mainly in Brazil and Venezuela, could have a strong impact on regional export trade flows, but these may face delays as financing remains an issue.

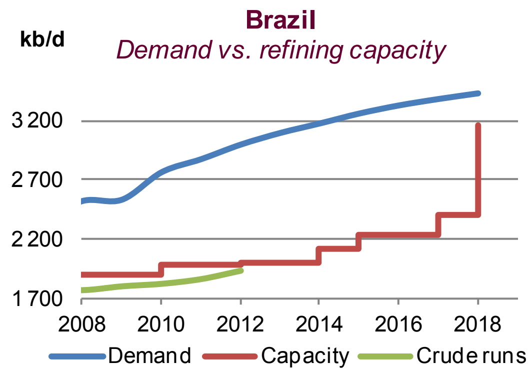




Latin America Refining Capacity

mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	6.15	5.93	6.21	6.39	6.48	6.70	7.46
Upgrading ratio	*40%*	*41%*	*41%*	*43%*	*43%*	*46%*	*47%*
Light Oil Processing							
Reforming	0.36	0.37	0.40	0.42	0.45	0.47	0.51
Isomerisation	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Alkylation	0.11	0.11	0.14	0.14	0.14	0.15	0.15
Bottom of the barrel processing							
FCC/RFCC	1.23	1.24	1.27	1.27	1.29	1.40	1.51
Hydrocracking	0.15	0.18	0.18	0.28	0.28	0.38	0.53
Coking	0.60	0.55	0.58	0.65	0.65	0.68	0.68
Thermal Crack./VBU	0.32	0.29	0.29	0.29	0.29	0.30	0.30
Hydroprocessing	2.27	2.36	2.47	2.63	2.63	2.68	2.88

Brazil is leading the boost to 7.5 mb/d capacity by 2018 in Latin American. Robust domestic demand and a shortfall in refining capacity have pushed Petrobras to steadily increase its imports of gasoline and diesel fuel over the past two years, resulting in steep losses in the company's refining operations as domestic prices remain below market prices. Recently, the Brazilian government has decided to raise domestic gasoline and diesel retail prices, but the measure was considered insufficient by investors because of its limited impact on ethanol demand. The price differential between the two fuels remains too narrow to shift consumers' behaviour. In order to curb gasoline imports and support sugarcane producers, the Brazilian government announced in mid-April that the percent of ethanol blended into Brazilian gasoline would be increased from 20% to 25% starting in May 2013.



Petrobras has plans to build three refineries by 2018. The next refinery currently being built is the

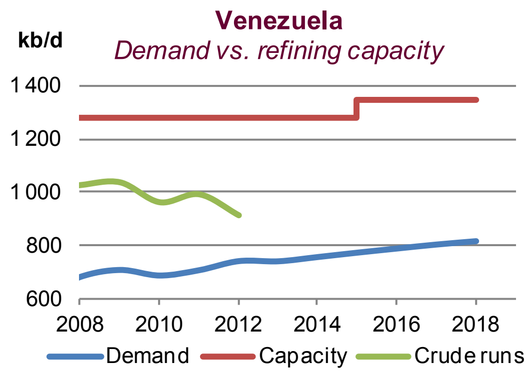
230 kb/d Abreu e Lima plant. In 2005, the governments of Venezuela and Brazil agreed to jointly build a refinery in the northeast Brazilian state of Pernambuco to process heavy crude oil. Originally, PDVSA was to take a 40% stake in the project, but missed several deadlines to pay for its share. Petrobras started construction on its own in 2007 and participation of PDVSA still remains uncertain. Completion of Phase 1 (115 kb/d) is expected at the end of 2014, and Phase 2 in 2015. The second project to be completed by 2017 is the first phase of the Comperj refinery and petrochemical project in Rio de Janeiro state. The second phase in 2018 will boost that capacity to 330 kb/d. Finally, the third project included in our assessment is the Premium II 300 kb/d refinery in Ceara state.

Although there is a large requirement for additional capacity in the country, Petrobras is having difficulties in financing its downstream expansion plans, estimated at USD 43.2 billion in its latest 2013-17 business plan, and projects are likely to be delayed. The state-owned company is selling of some investments, such as some assets outside the country in Argentina, but the company will need to find strategic partners to finance its ambitious program. China's Sinopec and Petrobras have already begun discussing the construction of the Premium refinery.

Elsewhere in the region, **Colombia**'s state-owned company Ecopetrol is upgrading its two main refineries. The Reficar (Cartagena) refinery modernisation project should be commissioned by 1H14. The project will boost refining capacity from 80 kb/d to 165 kb/d, increasing conversion yields from 76% to 97% from heavy, extra-heavy and sour crude oils. The modernisation of the Barrancabermeja refinery will be completed in 3Q17. The objective of the project is to increase the capacity of the 205 kb/d refinery by 45 kb/d, while increasing conversion yields and production of low-sulphur fuels.

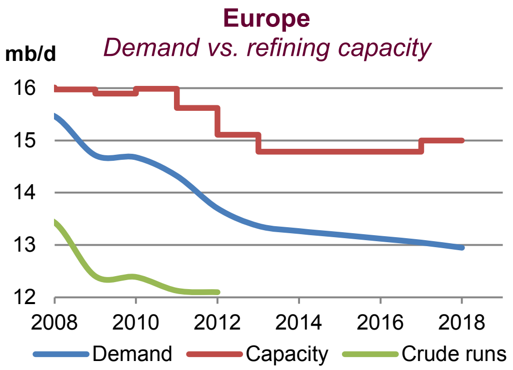
In **Peru**, the long announced upgrade and expansion project at Talara's 62 kb/d refinery, which was to expand the capacity of the refinery to 95 kb/d, has been cancelled for budgetary reasons. The refinery should now invest only in a desulphurization plant to produce 50 ppm products, from more than 2 500 ppm today.

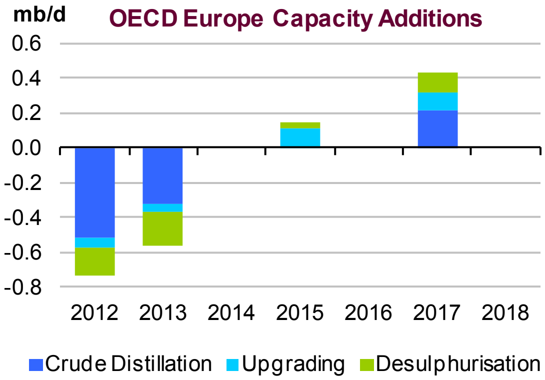
In **Venezuela**, our forecast remains bearish for the next five years, as the country is struggling to maintain its current refinery capacity, following the numerous accidents, which have affected all its refineries over the last two years. Currently, PDVSA has a refining capacity of 1.3 mb/d and had planned to increase it by more than 60% by 2019, following increases in heavy crude oil as specified in the government strategic plan, *Plan Siembra Petrolera.* The latest explosion at 645 kb/d Amuay refinery in late summer 2012, which killed 42 people and left the refinery operating at just half the nameplate capacity since, has shed light on years of mismanagement, delays in major maintenance and underinvestment. Projects under study include the 400 kb/d Cabruta plant, a project of deep conversion in Puerto la Cruz and a new 240 kb/d refinery to be built by ENI (Refineria Petrobicentenario). The current state of these projects is unclear and will probably be commissioned after 2018. Only the 60 kb/d Santa Ines refinery has been included in our forecast.



Europe: a temporary truce

By the end of 2012, **OECD European** refinery crude distillation capacity had declined to 15.1 mb/d, following the closure of four additional refineries, Paramo's Pardubice in Czech Republic, LyondellBasel's 105 kb/d Berre L'Etang in France, Raffineria di Roma's 89 kb/d in Italy and Petroplus 220 kb/d Coryton in UK. In 2013, 352 kb/d of refinery closures have so far been announced, with the closure of the 162 kb/d Petroplus plant at Petite Couronne, Shell's 110 kb/d Harburg refinery and Eni's 80 kb/d Porto Maghera facility.





Since 2008, 15 refineries have been shutdown in Europe, with a total capacity of 1.7 mb/d. Average utilisation rates have been steadily decreasing year after year, falling to 80% in 2012 against 85% in 2006. Crude oil distillation capacity in OECD Europe amounts to approximately 16% of the world total. As a result of capacity rationalisation in Europe, as well as new capacity built in non-OECD regions, the European share of global capacity should slip to 14% in 2018. Once the second-largest regional refining center in the world, Europe will relinquish its place to China before being overtaken after 2018 by Other Asia.

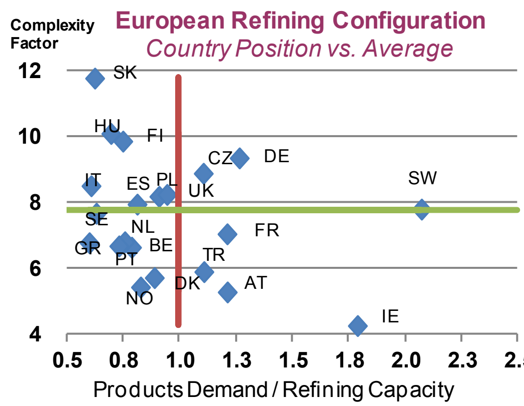
Conversion capacity in 2012 was nearly 39% of the region's primary distillation capacity, which is a good indicator of a developed refining industry. This figure should increase to 41% in 2018 as more plants are closed. Total capacity of hydroskimming plants, the simplest types of refinery, is estimated at 620 kb/d. These refineries are the most at risk, as margins for this kind of plants remain under pressure.

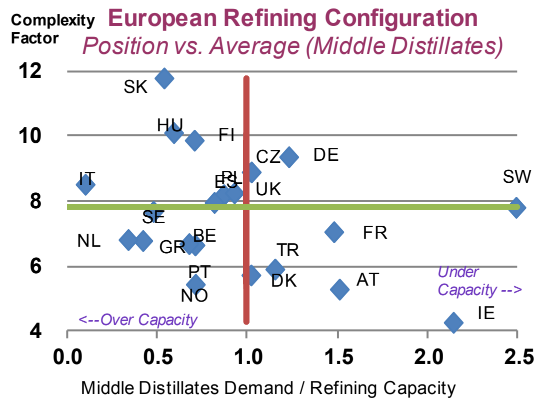
Significant differences, however, exist between countries, both in terms of total capacity versus demand and refinery complexity. On average, two-thirds of European countries are in an over-capacity position when compared with their domestic demand. One-third of the countries are both in an over capacity configuration and present a low refining complexity index. However, the picture is even more scattered when looking at the countries' positioning regarding middle distillate and gasoline demand.

Despite refinery shut downs, Europe continues to exhibit a structural gasoline surplus and the current mix of conversion capacity does not address the diesel shortfall while still producing gasoline in surplus.

OECD Europe Refining Capacity

mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	**15.11**	**14.78**	**14.78**	**14.78**	**14.78**	**15.00**	**15.00**
Upgrading ratio	*39%*	*40%*	*40%*	*41%*	*41%*	*41%*	*41%*
Light Oil Processing							
Reforming	2.22	2.17	2.17	2.17	2.17	2.20	2.20
Isomerisation	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Alkylation	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Bottom of the barrel processing							
FCC/RFCC	2.20	2.16	2.16	2.16	2.16	2.16	2.16
Hydrocracking	1.73	1.77	1.77	1.82	1.82	1.88	1.88
Coking	0.46	0.46	0.46	0.53	0.53	0.57	0.57
Thermal Crack./VBU	1.49	1.44	1.44	1.44	1.44	1.44	1.44
Hydroprocessing	10.62	10.51	10.51	10.54	10.54	10.66	10.66





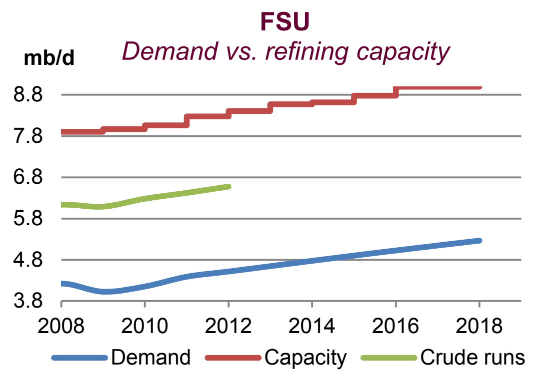
In response, some European refiners have invested in hydrocrackers and additional conversion units like Portugal's Galp, which commissioned a new 43 kb/d hydrocracker at the beginning of 2013. Other new hydrocracker units have been reported lately in France (Total's Gonfreville) and Greece (Hellenic' Elefinas) while deep conversion units like coker units have been installed in Greece and Spain. Interestingly, refinery crude runs in these countries (mainly Spain and Portugal) seem to have rebounded when elsewhere in the region crude runs are on a steep declining slope. However, continued sluggish demand in continental Europe, flagging refining margins, increased competition from new refineries in Russia, Asia and the Middle East and decreasing North American gasoline exports may push European refiners to find new markets or restructure.

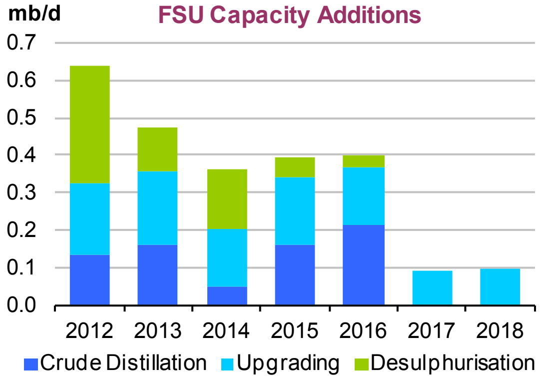
Between 2008 and 2011, some refiners have found support through alliances or acquisitions with state-owned oil companies from emerging countries like China, India or Russia. Lukoil was by far the most visible foreign partner in Europe with stakes in four refineries (Bourgas, Ploiesti, Augusta and Vlissingen). Petrochina acquired 50% of the Grangemounth and Fos Lavera refinery while Indian Essar bought the UK Stanlow refinery. Since then, only Russia has extended its integration into the European refining sector. Lukoil finally took an 80% stake in ERG's ISAB plant in Sicily while Rosneft gained ownership of 240 kb/d of German refining capacity through its entry into the Ruhroel JV with BP in 2011, replacing PDVSA. More recently, some Italian refiners have signed crude oil supply deals with Russian companies, including Russia's Rosneft, which said that it will take a 21% holding in the 300 kb/d Saras plant and also signed crude supply deals with Eni, PKN Orlen (for Plock refinery), Shell and Total.

By the end of the forecast period, we should see a new 200 kb/d refinery in Turkey. Azerbaijan's Socar is developing the Star refinery at Aliaga, on Turkey's Aegean coast, close to a petrochemical plant and the BTC pipeline. Socar will hold 81.5% equity in the project and Turkish's Turcas 18.5%. The project is expected to come on stream in 2017.

FSU: East-West arbitrage

Overall, **FSU** refinery crude distillation capacity in 2012 was 8.4 mb/d, following expansions at Gazprom's Salavat refinery and TNK-BP's Ryazan. Average capacity utilisation reached 78%, supported by high crude runs in Russia, Lithuania and Belarus. In the rest of the region, the utilisation rate is rather low, as in Ukraine where it fell to 10% in 2012.



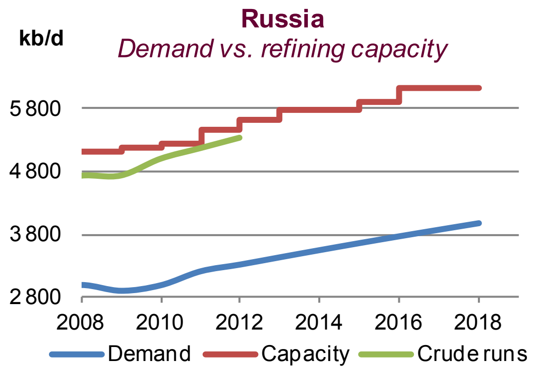


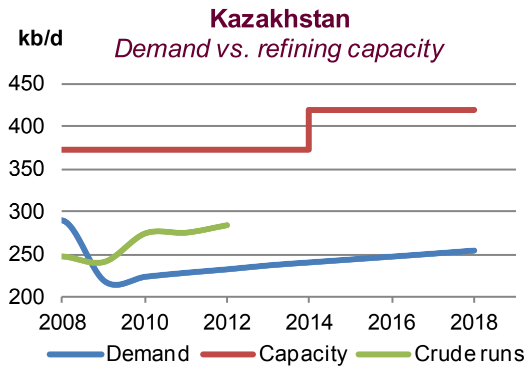
Former Soviet Union Refining Capacity

mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	8.41	8.57	8.62	8.78	8.99	8.99	8.99
Upgrading ratio	*26%*	*28%*	*30%*	*32%*	*33%*	*34%*	*36%*
Light Oil Processing							
Reforming	1.21	1.21	1.26	1.26	1.26	1.26	1.26
Isomerisation	0.24	0.24	0.26	0.27	0.27	0.27	0.27
Alkylation	0.13	0.13	0.13	0.13	0.14	0.14	0.14
Bottom of the Barrel Processing							
FCC/RFCC	0.80	0.86	0.86	0.91	0.95	0.95	1.05
Hydrocracking	0.25	0.31	0.41	0.47	0.51	0.58	0.58
Coking	0.37	0.43	0.48	0.54	0.57	0.59	0.59
Thermal Crack./VBU	0.65	0.66	0.66	0.66	0.66	0.66	0.66
Hydroprocessing	4.12	4.21	4.37	4.42	4.46	4.46	4.46

Crude distillation in the former Soviet Union amounts to 9% of world capacity and its conversion capacity is about 26% of the region's primary distillation capacity. By the end of 2018, total regional capacity should reach 9.0 mb/d and conversion ratio of 36% as many refiners focus on improving products quality and yields so they may enter profitable export markets rather than on increasing capacity as the region is already in net surplus. Crude capacity additions, included in our forecast are mainly expected at Lukoil's Nizhny Novgorod and Volgograd refineries, Rosneft's Tuapse plant and in Kazakhstan at Atyrau refinery.

As part of the downstream modernisation agreement Russian refiners signed with federal authorities in 2011, about 15 secondary processing refinery units are going to be built or upgraded around the country. These units are mainly isomerisation units, FCC gasoline hydrodesulfurisation, hydrocrackers and diesel hydrodesulfurisation designed to produce products meeting the most stringent technical and environmental standards on the export market but also on the domestic market as Euro III standards have been in force since January. The ultimate aim of the upgrades is to allow Russia to increase its output of gasoline and diesel and sharply reduce fuel oil production.



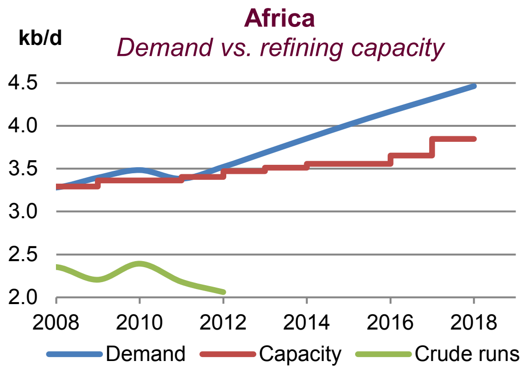


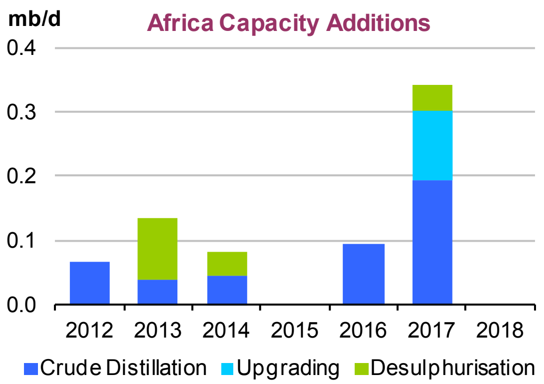
Although the modernisation programme of Russian refineries is behind schedule, the impact of recent refinery upgrades on the international market is already visible. Last year, exports of 10 ppm diesel from Russian refineries surged by more than 12% when Taif's 160 kb/d Nizhnekamsk, Gazprom's 420 kb/d Omsk and TNK-BP's 140 kb/d Saratov refineries were upgraded. As upgrading is accelerating, it is likely that Russian exports of low-sulphur diesel will keep on increasing, finding outlets in North Europe, in Turkey and the Mediterranean. Low-sulphur diesel exports from Russia could rise to about 300 kb/d in the coming years. Exports to Europe are split mainly in two directions, without relying on neighbouring countries for transit. In the north, Euro V diesel exports are directed through the 175 kb/d Sever pipeline to Primorsk, where capacity may be expanded to 245 kb/d in 2015. However, as demand in northern Europe remains subdued, Russia has also targeted Turkey and the Mediterranean markets by building a 1 465 km length, 180 kb/d pipeline, connecting the refineries in Saratov, Volgograd and Krasnodar with the port of Novorossiysk on the Black Sea. The so-called Yug (South) pipeline is expected to come on line in 2016-17. The recent decision of Lukoil to launch a major upgrade at its 200 kb/d Volgograd refinery, increasing its diesel production by 37 kb/d, illustrates well the current strategy followed by Russian refiners.

Elsewhere in the region, the development of the refining sector is mainly taking place in countries that are part of the customs union, Belarus and Kazakhstan. The refineries in these countries benefit from cheaper Russian crude when compared to other countries as Ukraine, whose plants are currently running at less than 10% utilisation. Kazakhstan is upgrading all three of its refineries to produce cleaner products meeting Euro V standards. As part of the customs union, Kazakhstan supplies Russia with crude oil and receives in exchange light refined products. Recently, this agreement has been questioned by Kazakhstan, which is also trying to find new product suppliers and crude markets, mainly in China.

Africa: still lagging behind demand

In 2012, African refinery crude distillation capacity reached 3.47 million b/d following capacity increases at Samir's Mohammedia refinery. Based on distillation capacity alone, the region would appear to have just about adequate capacity to meet its demand, but utilisation rates are particularly low, averaging 60% in 2012, as planned and unplanned refinery outages in Libya, Algeria and Egypt have considerably affected refinery crude runs this year. As a consequence, the region is currently a net product importer.





Africa Refining Capacity

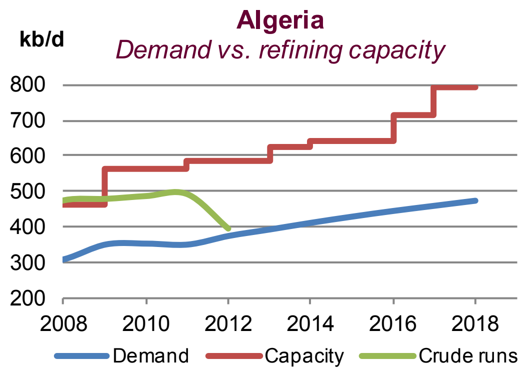
mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	3.47	3.51	3.56	3.56	3.65	3.85	3.85
Upgrading ratio	14%	14%	14%	14%	14%	16%	16%
Light Oil Processing							
Reforming	0.50	0.55	0.57	0.57	0.57	0.58	0.58
Isomerisation	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Alkylation	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Bottom of the Barrel Processing							
FCC/RFCC	0.21	0.21	0.21	0.21	0.21	0.26	0.26
Hydrocracking	0.10	0.10	0.10	0.10	0.10	0.14	0.14
Coking	0.06	0.06	0.06	0.06	0.06	0.07	0.07
Thermal Crack./VBU	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Hydroprocessing	0.97	1.01	1.03	1.03	1.03	1.08	1.08

Our forecast for 2013-18 is rather bearish as many North African refinery expansions have been delayed or put on hold. We expect total regional crude distillation capacity to remain at 4% of world refining capacity, reaching 3.8 mb/d in 2018. The conversion capacity at the end of 2012 was 14% of the region's primary distillation capacity, the lowest in the world and it should only slightly increase to 16% by the end of the forecast period.

As usual, many projects were announced in Nigeria, but with existing refineries underutilised these projects were delayed, shelved or cancelled largely as a result of financing difficulties, regulatory uncertainties and security concerns. The most recent example is the new 300 kb/d Lekki refinery project, supported by the Lagos State government and NNPC in collaboration with a consortium of Chinese investors, which was cancelled following a revision to the proposed Petroleum Industry Bill

(PIB). Nigeria has embarked on a rather ambitious maintenance and upgrading programme to increase the refining capacity of the nation's three refineries, to 90% of installed capacity by 2014, against less than 30% today.

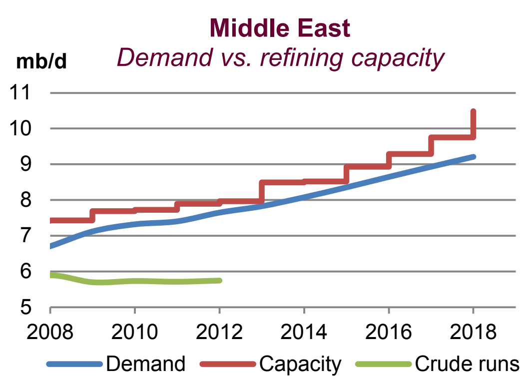
In 2013, the main regional refining project is in Algeria. State-owned Sonatrach is in the process of upgrading various units at its Skikda plant. As a result of the upgrade, the capacity of the refinery will be increased by 40 kb/d to 300 kb/d. This project was affected by several incidents in late 2012, forcing the refinery to operate at half capacity since the beginning of 2013. The refinery was expected to be fully operational in early March. Other projects in Algeria are forecast to be completed in the next five years, including capacity extension at the Skikda (+115 kb/d), Arzew (+75 kb/d) and Alger (+18 kb/d) refineries.

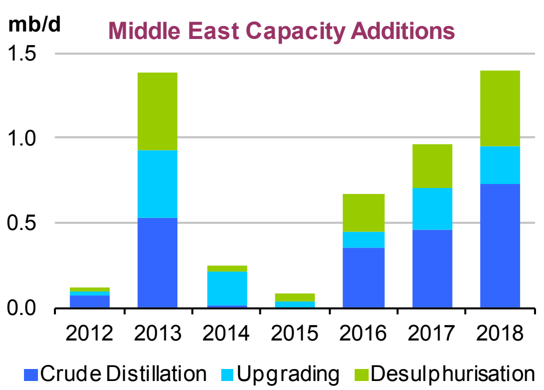


Although still in discussion, our forecast includes a new grass root refinery in Uganda by the end of the forecast period. The discovery of up to 2.5 billion barrels of crude oil in the Lake Albert Rift Basin has sparked strong interest for a new refinery in East Africa. Currently, there is only one functioning oil refinery in East Africa, Kenya's Mombasa refinery, owned jointly by the Kenyan government and India's Essar Energy, which is operating only at 50% capacity. Uganda's parliament passed a new law in early 2013 on petroleum refining, opening the way for the construction of a new refinery. Initially planning for a major 200 kb/d refinery, Uganda has finally agreed with France's Total and China's CNOOC to build a much smaller refinery of 20 kb/d, expandable to 60 kb/d.

Middle East: major export refineries

In 2012, Middle Eastern crude oil distillation capacity reached 7.97 mb/d, including condensate distillation capacity. Globally, there is an excess of refining capacity but average capacity utilisation in the region is rather low, averaging 74% over the last five years. Refining expansion will be aggressive over the next five years as more than 2.5 mb/d of crude capacity is expected to come on-line during the 2013-18 period, mostly in Saudi Arabia. Smaller expansions are expected in Qatar, Iran, Iraq and Oman.



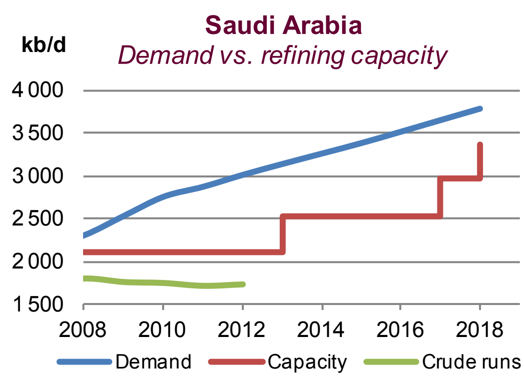


Middle East Refining Capacity

mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	7.97	8.50	8.52	8.93	9.29	9.76	10.49
Upgrading ratio	26%	30%	33%	36%	36%	37%	37%
Light Oil Processing							
Reforming	1.02	1.13	1.17	1.22	1.25	1.34	1.41
Isomerization	0.15	0.21	0.21	0.21	0.22	0.22	0.25
Alkylation	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Bottom of the barrel processing							
FCC/RFCC	0.58	0.77	0.95	1.11	1.14	1.14	1.22
Hydrocracking	0.67	0.77	0.77	0.86	0.93	1.05	1.09
Coking	0.09	0.19	0.19	0.19	0.19	0.31	0.41
Thermal Crack./VBU	0.48	0.48	0.50	0.50	0.50	0.50	0.50
Hydroprocessing	3.36	3.79	3.82	4.01	4.05	4.31	4.76

By 2018, overall regional crude capacity should reach 10.5 mb/d about 10% of world capacity against 8% in 2012. About half of the increase in refining capacity will be built in Saudi Arabia where three majors grass root projects are expected.

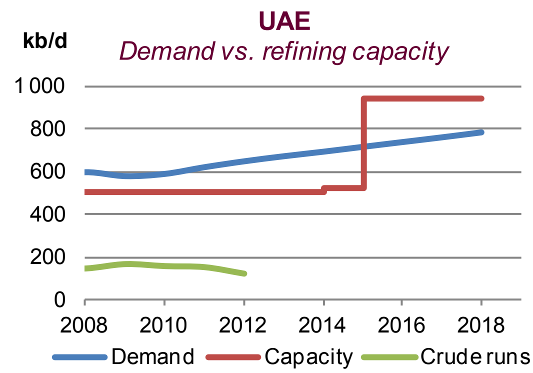
Many projects in the region are also designed to improve fuel quality and increase the yield of clean fuels to meet stricter environmental regulations in the future, while reducing the amount of fuel oil. The upgrading ratio is expected to increase from 26% in 2012 to 37% in 2018, with major upgrading projects taking place in Kuwait, Iran and Oman.

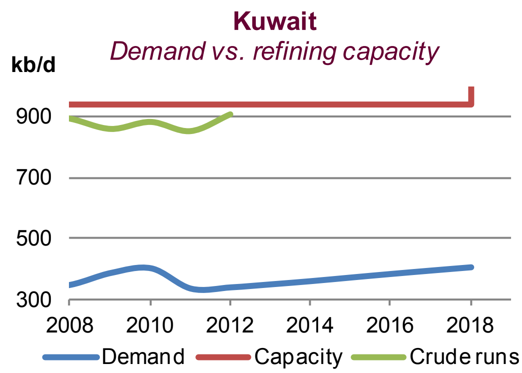


During the 2013-18 period, most of the refining capacity increases in the Middle East region will be in Saudi Arabia. By the end of 2012, the country's refining capacity was 2.1 mb/d, and refineries were operating on average at 82% of total capacity. In the next five years, three main refining projects are expected to come online. The first one, a 400 kb/d refinery being built by Total and Saudi Arabia at Jubail, is expected to start full commercial operations by the end of 2013. The joint venture (62.5% Saudi Arabia, 37.5% Total) is also developing a petrochemicals complex to be integrated with the refinery. The second project is the Jazan refinery, which will process 400 kb/d of Arabian Heavy and Arabian Medium crude oil to produce gasoline, ultra-low sulfur diesel, benzene and paraxylene by 2016-17. A 2 400 MW high-efficiency combined-cycle power plant is also part of the project. Initially planned for 2018, the project has been moved forward after receiving recently strong support from King Abdullah, urging Saudi Aramco to complete the first phase of its infrastructure project. The third project is Aramco's Yasref 400 kb/d refinery, being built at Yanbu, on the Red Sea coast with China's Sinopec. The project is scheduled for 2017-18. Like Jubail, Yanbu has been specifically designed to run on heavy crude oil from the newly developed Manifa oil field. By far the largest of the new Saudi oilfields, Manifa is expected to produce around 500 kb/d by mid-2013 and should hit full flow of 900 kb/d of heavy crude in 2014.

The repercussions of these new refineries on the international products market will be significant, mainly on the diesel and gasoline market. Currently, the country is short of gasoline and low-sulphur diesel as consumption increases steadily. Jubail alone could increase Saudi Arabia's high-quality diesel production by 175 kb/d once it is fully operational. By 2018, this figure could reach 460 kb/d with the start up of the other projects. In 2012, the country imported on average 170 kb/d of diesel.

Refiners currently exporting products to the kingdom, like Indian or southern European refiners will be hit. Although the former could easily re-route their export flows to the Asian region, southern European exporters will face much more difficulties in finding alternative outlets. However, diesel imports will not entirely stop, as the high-quality diesel the new Saudi Arabian refineries will produce will not be used in domestic power plants but rather exported.





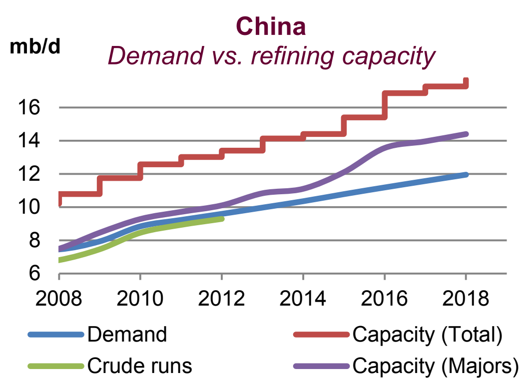
After Saudi Arabia, the highest regional refinery capacity increase will take place in the UAE in 2015 with the expansion by 420 kb/d of Abu Dhabi's Adnoc Ruwais refinery. This high-conversion project, will process heavy residue produced by other Adnoc refineries into lighter products. This project should substantially reduce Abu Dhabi's fuel oil exports.

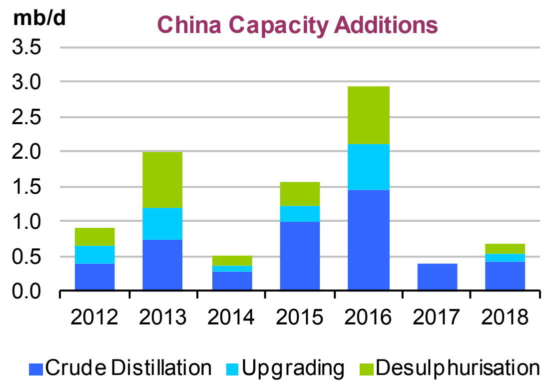
Another major initiative aimed at increasing conversion products is taking place in Kuwait with the 'Clean Fuels Project' (CFP) at Mina Abdullah and Mina Al-Ahmadi refineries. The country has ambitious plans as it is still going ahead with the Al-Zour refinery project, the Middle East's largest oil refinery (615 kb/d). After the start-up of the Al Zour facility (by 2022), KNPC will close the Shuaiba refinery and will operate its three refineries as an integrated complex of about 800 kb/d of capacity.

Elsewhere in the region, our forecast includes about 775 kb/d of additional capacity, mainly in Oman (+250 kb/d) with the extension of ORPIC's Sohar refinery to 188 kb/d, in Iran (+220 kb/d), Qatar (+145 kb/d) and Iraq (+140 kb/d). Perhaps due to US and European sanctions, Iran has boosted its processing capacity in various refineries, as at its Arak refinery where capacity has been increased from 170 kb/d to 250 kb/d. This enables it to use previously exported oil domestically, while reducing its need for product imports, particularly gasoline. Other expansion projects are expected at Bandar Abbas refinery with a new condensate splitter coming online by 2018. However, most of the investments in Iran are upgrading projects aimed at increasing the production of gasoline and diesel while reducing the amount of fuel oil.

China: securing crude supply with more joint venture projects

By the end of 2012, China refining crude distillation capacity reached 13.41 mb/d, representing about 14% of world topping capacity. China's refining industry is commonly divided into two groups: independent refiners and major refiners. There are about 80 major refineries belonging to China National Petroleum Corporation (CNPC), China Petrochemical Corporation (Sinopec), China Offshore Oil Corporation (CNOOC), Shaanxi Yanchang Petroleum Group (SYPG) and China North Industries Group Corporation (CNGC). Total capacity of major refiners in 2012 was 10.1 mb/d. Our assessments of independent refiners' crude distillation capacity have been therefore revised higher, from 2.5 mb/d to 3.3 mb/d.





China Refining Capacity

mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	13.41	14.14	14.41	15.41	16.87	17.27	17.71
Upgrading ratio	66%	67%	67%	64%	64%	62%	61%
Light Oil Processing							
Reforming	0.76	0.88	0.91	1.05	1.21	1.21	1.24
Isomerisation	0.01	0.02	0.02	0.02	0.07	0.07	0.08
Alkylation	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Bottom of the barrel processing							
FCC/RFCC	3.12	3.35	3.39	3.44	3.46	3.46	3.46
Hydrocracking	1.20	1.40	1.45	1.50	1.77	1.77	1.81
Coking	1.82	1.85	1.87	1.97	2.31	2.31	2.37
Thermal Crack./VBU	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Hydroprocessing	4.18	4.98	5.12	5.45	6.30	6.30	6.46

Net refinery capacity additions in 2012 totalled 390 kb/d of which 320 kb/d were commissioned in the fourth quarter, including Sinopec's Maoming refinery. Sinopec formally commissioned a 200 kb/d crude distillation unit (CDU) at the Maoming refinery in the southeast Guangdong Province. The new addition effectively raises the primary capacity at the refinery to over 400 kb/d, making it the third largest refinery in China after the Sinopec Zhenhai refinery and PetroChina's Dalian (WEPEC) refinery. Other capacity increases were completed at Sinopec's 160 kb/d Jinling Petchem, and CNPC's 100 kb/d Hohhot Petchem. In total, 560 kb/d of new capacity was added in this last quarter, while 240 kb/d of capacity was scrapped.

In 2012, Shandong Dongming Petrochemicals Group became the largest independent refinery in China following the commissioning of a new 120 kb/d crude distillation unit at the Dongming refinery in Shandong Province. The new addition raised the total crude processing capacity at the Dongming refinery to 230 kb/d.

Over the course of 2013, we expect about 730 kb/d of net capacity additions. Sinochem's 240 kb/d Quanzhou refinery in Fujain province is expected to come on stream by the end of year, just as Petrochina's 200 kb/d Pengzhou refinery is expected to start up in Sichuan. The firm is also planning a 100 kb/d expansion at Huabei in Hebei. Chinese's independent refiners aim to add a further 600 kb/d of capacity this year amid concerns over fuel taxes, which could severely impact their refining margins and finally push them to closure.

In a move to rationalise its refining sector, the China's State Administration of Taxation issued new tax regulations to take effect from 1 January 2013. These new measures included levying a consumption tax on certain petroleum products that were previously exempt such as MTBE, aromatics and naphtha when used for gasoline production. These measures should drastically impact the profitability of the small teapot refineries, which have little or no secondary processing capacities. Typically, those refineries were importing fuel oil and feedstock without paying taxes to produce mostly gasoil and gasoline for sale in the domestic market. The gasoline produced was then blended with MTBE or aromatics in order to meet the national fuel standards. The new tax imposed will make blended gasoline production costs on a par with, or even higher than, the cost of standard gasoline produced by the state refiners, therefore denting further their weak margins. China's new fuel consumption tax up to now, however, has had no impact on the market and on business operations as most operators and traders have so far avoided paying the tax by taking advantage of loopholes in the system.

The fate of independent refiners in China is regularly discussed as the government policy swings between toughness and '*laissez-faire*'. With an estimated total processing capacity of 3.3 mb/d, of which about 2.0 mb/d is in the Shandong province, many have a capacity of less then or around 40 kb/d. In Shandong and NorthWest China, crude distillation capacity of independent refiners averages 35 kb/d and only 15 kb/d in other provinces like Guangdong, North and East China. As per Chinese government decisions, these small plants will be closed by 2013 but the remaining ones could be finally granted a license to directly import crude oil like ChemChina, which was the first independent refiner to receive a quota to import 200 kb/d in 2013.

The likely outcome of these regulations is still unclear. If the license to import crude oil is extended to all independent refiners in China, however, fuel oil market dynamics in the region could be severely reshaped.

In order to secure their feedstock supply and improve their operating margins, some independents are progressively being acquired by state-owned refiners. CNOOC, ChemChina, Sinochem and Petrochina have all recently acquired independents. Usually, under the terms of the agreement with independents, state-owned companies provide the crude, get the products back and even take responsibility for the sales of all the oil products. Most independent refiners have expanded their capacities or benefited from new pipeline infrastructure after starting cooperation with state-owned refiners.

In our forecast, we have not included any capacity expansions as new regulations specify that any new crude distillation units should have a capacity over 200 kb/d and units below 40 kb/d should be closed down. Therefore, we consider that over the next five years, new additions will compensate for closures as independents will be more inclined to increase their yields, investing in secondary processing units rather than investing in new distillation units.

In 2015, 1 mb/d of new capacity will be added with the completion of major refineries like Sinopec's 240 kb/d Caofeidian and CNPC's 200 kb/d Kunming and Jinxi refineries.

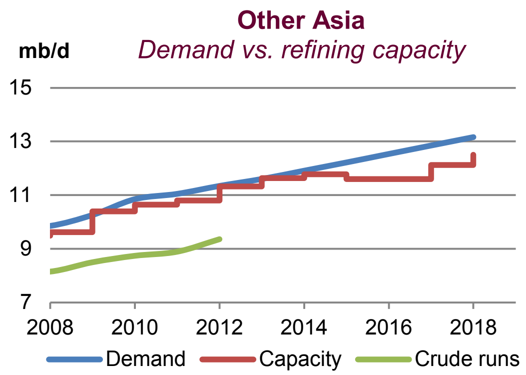
In 2016, many big joint refinery projects will be developed. Recently, Chinese state companies entered into joint ventures with oil producing national oil companies because they provided security of oil supply. There are currently three joint refinery projects being developed, two involving PetroChina's parent China National Petroleum Corp and one with Sinopec.

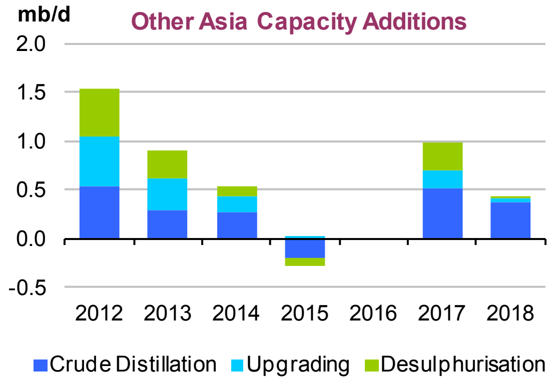
The first joint project is the CNPC 260 kb/d refinery partnering Russia's Rosneft in the eastern port city of Tianjin. The project broke ground in 2010 but made little progress because of profitability concerns. It has now been reactivated after the recent talks between Russia and China and Rosneft's decision to triple its supplies to China to 1 mb/d. Although still planned for 2015, this project could be delayed and will likely only start operations in 2016. The second CNPC's joint venture is with Venezuela's state-owned PDVSA, for a 400 kb/d b/d refinery in Jieyang city in Guangdong. Construction started in May last year and is slated to be ready by 2016. Finally, the last venture is between Sinopec and Kuwait's KPC for a 300 kb/d refinery in the southern Guangdong province's city of Zhanjiang. The project has already been approved and is being constructed but its ownership structure is unclear and Sinopec could finally just proceed with the refinery on its own.

A major obstacle for foreign partners in joint ventures with Chinese companies is the oil product marketing rights as product prices remain controlled by the government. In order to mitigate refining losses in the domestic market, many foreign companies struggle with Chinese companies to get marketing rights. The recent petroleum products price reform initiated at the beginning of 2013, with the aim to move domestic prices closer in line with international crudes so they would reflect the crude procurement costs that refiners bear, is a positive aspect for foreign companies investing in China.

Other Asia: keeping pace with demand

By the end of 2012, **Other Asia** refinery crude distillation capacity reached 11.3 mb/d with capacity and demand expanding at about same rate. Utilisation rates in 2012 remained low at 83%, in line with levels reached years before. Over the period 2013-18, about 1.3 mb/d of additional capacity are expected to be commissioned, mainly in India (+380 kb/d), in Malaysia (+300 kb/d), in Pakistan (+260 kb/d) and in Vietnam (+200 kb/d). The number of projects reflects the aggressive expansion required to keep pace with the rapid growth in demand and the expansion of export production capability, mainly in India. Demand for petroleum products exceeds refining capacity by the end of the forecast period, requiring incremental products to be imported mainly from the Middle East.

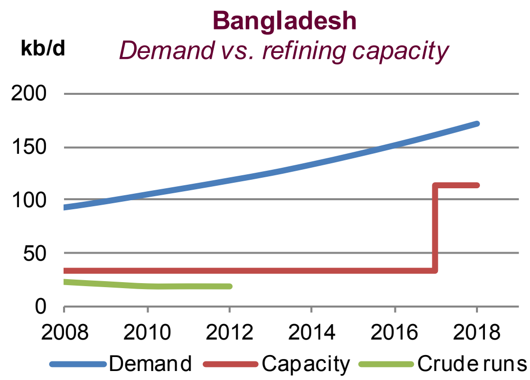




Other Asia Refining Capacity

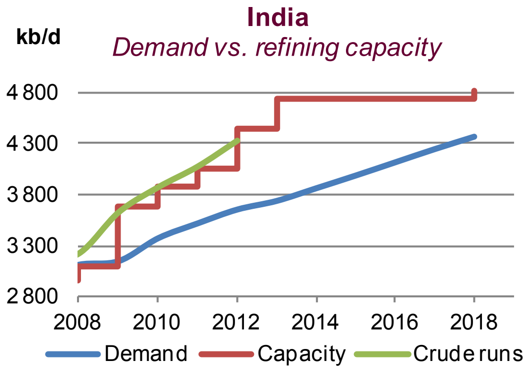
mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	11.33	11.63	11.78	11.60	11.60	12.12	12.50
Upgrading ratio	*42%*	*44%*	*45%*	*46%*	*46%*	*46%*	*45%*
Light Oil Processing							
Reforming	1.19	1.28	1.28	1.26	1.26	1.34	1.34
Isomerisation	0.25	0.27	0.29	0.28	0.28	0.29	0.29
Alkylation	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Bottom of the barrel processing							
FCC/RFCC	1.66	1.78	1.88	1.88	1.88	1.97	1.97
Hydrocracking	0.99	1.10	1.11	1.11	1.11	1.16	1.20
Coking	0.80	0.87	0.91	0.93	0.93	0.97	0.97
Thermal Crack./VBU	0.62	0.62	0.63	0.63	0.63	0.63	0.63
Hydroprocessing	5.48	5.72	5.82	5.72	5.72	5.98	5.99

In terms of complexity, the upgrading ratio gradually increases from 42% in 2012 to more than 45% as many new refineries in the region focus on the processing of heavy crude oil, from the Middle East and Latin America mainly.



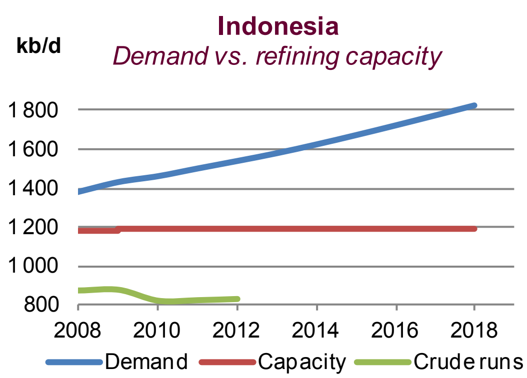
In **Bangladesh**, the private-public partnership (PPP) project for expansion of the Eastern Refinery Limited (ERL) has been cancelled. The objective of ERL's balancing, modernisation, rehabilitation and expansion (BMRE) project was to expand the capacity of the sole refinery of the country from 30 kb/d to 100 kb/d. Project completion was expected by 2015, but has finally been cancelled, both for financing reasons and on technical grounds as the current refinery is more than 50 years old. The government has now opted for a new build, in joint-venture with Kuwait Petroleum International (KPI), with an 80 kb/d-100 kb/d refinery planned. The project could be completed by 2017. Although still in very preliminary stages, this project is quite essential for Bangladesh, as the country has seen its oil import bill increasing steadily over the last three years. A new refinery project is also compatible with the recent discovery of new oil resources, estimated at 140 million barrels.

In 2013, the Chinese company Zhejiang Hengyi has secured regulatory approval from China to build a new 160 kb/d refinery in **Brunei**, at Pulau Muara Besar. The new refinery project is to secure Hengyi with paraxylene and benzene supply for its petrochemicals activities. Hengyi is a major producer of petrochemicals products, mainly pure terephthalic acid for the polyester chain. Although approved, we estimate that this project could be completed by 2020, beyond the time horizon of this report. Brunei currently has only one refinery operating with a total capacity of 12 kb/d for a total demand of around 17 kb/d.



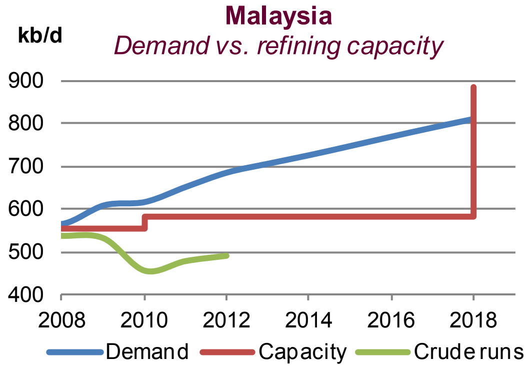
India's refining capacity at the end of 2012 was estimated at 4.4 mb/d and crude runs 4.3 mb/d. Indian refining capacity surged by 10% in 2012, following the completion of Essar Vadinar refinery's optimisation project, HPCL/MITTAL's Bathinda grass root refinery and additional capacities installed in various refineries. The Essar project has taken the capacity of the Vadinar Refinery in Gujarat to 400 kb/d, about 10% of total country refining capacity. The new project allows the refinery to process up to 80% of heavy crudes (below 25 API) and produce higher-grade products like Euro IV and Euro V. HPCL/MITTAL's newest 180 kb/d Bathinda refinery, completed at the beginning of 2012, and was expected to increase its capacity to 225 kb/d in the next two years. However, the expansion work has been delayed due to difficulties in integrating the refinery operations with the petrochemical segment and therefore this additional capacity has not been added to this forecast. Over the next five years, most of the increase in refining capacity will be reached in 2013-14 with the commissioning of two new refineries: Nagarjuna's 120kb/d Cuddalore refinery and Indian Oil's 300 kb/d Paradip refinery. The start-up date for the 120 kb/d Cuddalore's refinery, originally planned in 2011 has been delayed several times and is now expected to come on stream in 1Q14 after it was damaged during its construction by cyclone Thane, the strongest tropical cyclone of 2011 in the North Indian Ocean. Once complete, this will be the country's third privately-owned refinery after Essar Oil and Reliance. There is a possible expansion plan to double the capacity of this refinery by 2016, but it has not been considered in this report.

Indian IOC is aiming to start up its 300 kb/d Paradip refinery, on the east coast of India, in 4Q13 after years of delays. By the end of the forecast period (2018), we see India's refining capacity reaching 4.8mb/d on planned expansion at Indian Oil's 310 kb/d Koyali refinery, as many announced projects will probably be recast and scheduled for commissioning after 2018.

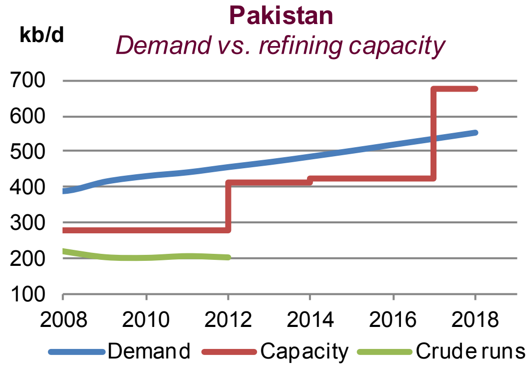


Indonesia's refining capacity in 2012 was 1.2 mb/d with refineries operating on average at less than 70% of total capacity. To satisfy its growing domestic market, the country has been studying for many years the feasibility of building new grassroot refinery projects. Currently, two projects are under consideration, with the first a partnership with KPC for a new 300 kb/d crude distillation unit at Balongan refinery and the second with Saudi Arabia and Shell for a 300 kb/d greenfield refinery at Tuban. These projects are still at a very early stage and have not been included in the forecast. To address its rising energy import bills, the country has been trying to cut motor fuels subsidies, which along with an economic slowdown could lead to a fall in imports. The only project included in our analysis is the Cilacap refinery upgrade project. Cilacap is Pertamina's largest refinery (339 kb/d), located on the island of Java. The refinery's upgrade includes the construction of a 62 kb/d residue fluid catalytic-cracking (RFCC) unit and other downstream units aimed at increasing refinery conversion and improving product quality. The project is expected to be completed by the third quarter of 2014.

Following Petronas' Melaka refinery expansion and upgrading project, **Malaysia** refining capacity by the end of 2012 reached 580 kb/d, and crude runs averaged 490 kb/d. Currently, Pertamina is undertaking a 300 kb/d refinery and petrochemical integrated development project (RAPID) in Pengerang, Southern Johor, Malaysia. The project, announced for 2017, could be delayed after the joint venture with BASF to produce specialty chemicals within the refinery was called off.

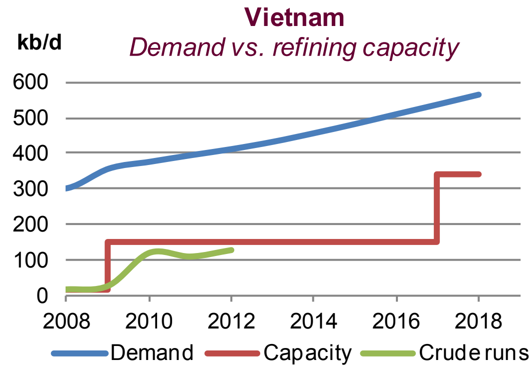


Pakistan oil product imports have steadily increased over the last years as the country has lagged in investing in refining capacity. By the end of 2012, Pakistan's Byco Oil had completed the country's single largest refinery at Mouza Kund, Balouchistan. This newly commissioned refinery has an installed refining capacity of 120 kb/d and would boost Pakistan's refining capacity by more than 45%, to 411 kb/d, significantly aiding in reducing the import deficit of refined petroleum products in the country. The new refinery is a relocation of Chevron's Gulf Refinery at Milford Haven, UK, which closed in 1997 before being purchased by Petroplus in 1998 and subsequently sold to Byco Oil Pakistan in 2006. The next investment phase is scheduled in 2018, with the IPIC/PARCO's 250 kb/d Khalifah Coastal Refinery. The project, jointly sponsored by the United Arab Emirates, has been put on hold several times since 2007 due to various issues but has been revived recently. This project competes with another option at Gwadar, on the Arabian coast close to the Strait of Hormuz. Last February, Pakistan formally handed over management of the port of Gwadar to a Chinese company, with possible plans to build an export refinery and a pipeline to pump Mideast crude through Pakistan to Xinjiang province. Iran has also expressed interest in building a major refinery in Gwadar. If one of these projects goes ahead, Pakistan could become a net petroleum products exporter mainly focused on Central Asia countries.



Vietnam's refining capacity at the end of 2012 was 149 kb/d and crude runs averaged 128 kb/d. Since the completion of the 130 kb/d Dung Quat in 2009, Vietnam has failed to bring on stream any of the several proposed new refineries despite steadily growing domestic demand. Together with

Indonesia, Vietnam is one of the top motor fuels importers in East Asia. In order to reduce its hefty energy import bills, the country is set to build a second refinery in the north. In early 2013, the construction of the 200 kb/d Nghi Son refinery and chemical complex in Vietnam was awarded to a consortium including JGC Corp. The Nighi Son refinery project, is sponsored by PetroVietnam (25.1%), Kuwait Petroleum International (35.1 %) and Mitsui Chemicals (4.7 %). Construction should start in 2Q13 and the plant is scheduled to start operation in the second quarter of 2017.



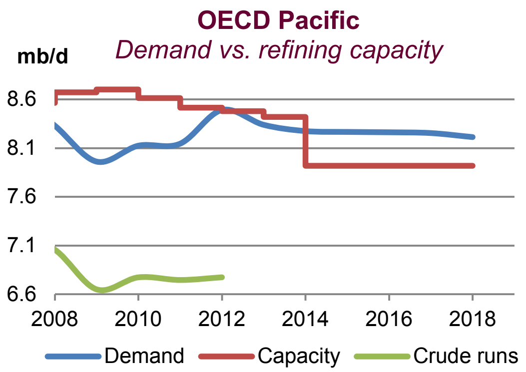
According to the 2020-25 Ministry of Trade and Industry's development plan, the objective of the Vietnamese government is to reach a refining capacity of 1.2 mb/d in 2025. Other possible projects are therefore under study, including an extension of existing Dung Quat refinery to 240 kb/d, a 200 kb/d refining and petrochemical complex at Long Son in the south, a 160 kb/d Vung Ro's refinery at Phu Yen, and a refining and petrochemical complex in the Nhon Economic Zone in joint venture with Thailand's PTT.

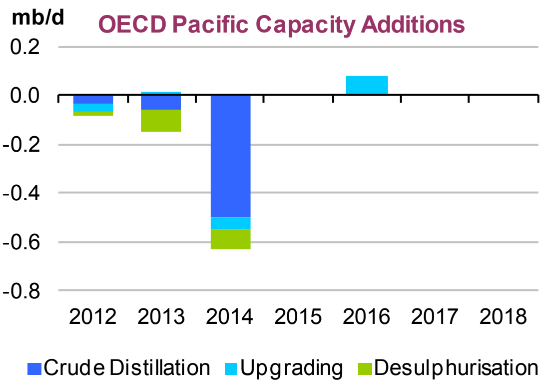
Asia Pacific: restructuring and consolidation

OECD Pacific's refining capacity was 8.5 mb/d in 2012. Since 2010, the refining sector in this region is undergoing complete restructuring, mainly in Japan and Australia. These restructurings should however culminate in 2014, leaving total refining capacity close to 8.0 mb/d. As inefficient refineries and units close, the regional conversion capacity will increase from 28% to 31% of the region's primary distillation capacity in 2018.

OECD Pacific Refining Capacity

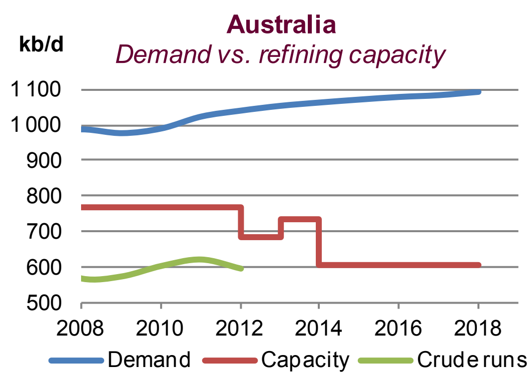
mb/d	end 2012	2013	2014	2015	2016	2017	2018
Crude Distillation Unit	8.48	8.42	7.92	7.92	7.92	7.92	7.92
Upgrading ratio	*28%*	*29%*	*30%*	*30%*	*31%*	*31%*	*31%*
Light Oil Processing							
Reforming	1.25	1.23	1.21	1.21	1.21	1.21	1.21
Isomerisation	0.07	0.07	0.06	0.06	0.06	0.06	0.06
Alkylation	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Bottom of the barrel processing							
FCC/RFCC	1.55	1.57	1.52	1.52	1.52	1.52	1.52
Hydrocracking	0.51	0.51	0.51	0.51	0.55	0.55	0.55
Coking	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Thermal Crack./VBU	-	-	-	-	0.04	0.04	0.04
Hydroprocessing	6.56	6.48	6.43	6.45	6.52	6.52	6.52



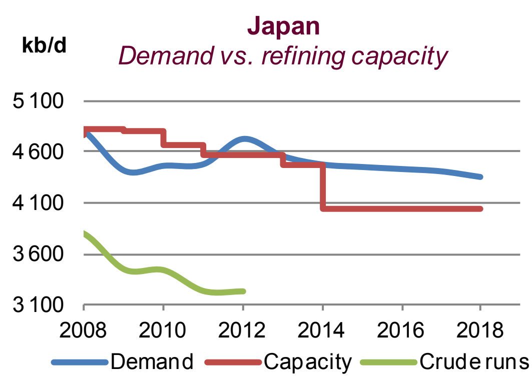


In **Australia,** Shell announced in early April that it is selling the Geelong refinery (110 kb/d), its last remaining Australian refinery after closing the Clyde refinery (85 kb/d) in 2012. The refinery could be converted into an import terminal, if no buyer is found before 2014.

In early 2012, seven major petroleum refineries were operating in Australia, with a total capacity of 768 kb/d, producing around 74% of the refined petroleum products consumed domestically. By the end of 2012, Shell's Clyde refinery was closed and Caltex announced the closure of its Kurnell refinery (124 kb/d) by the second half of 2014 as refiners face mounting competition from Asia. We expect the country's refinery capacity to decline by around 20% by 2015 to 609 kb/d.

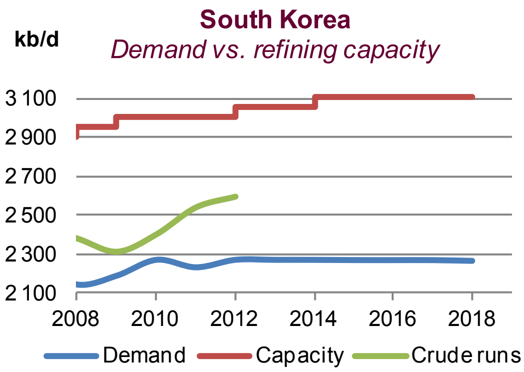


Following the Ministry of Economy Trade and Industry 2009 decree, **Japanese** refiners must meet a minimum cracking/CDU capacity ratio of 13% by March 2014. In order to meet this requirement, many refiners have announced their plans to reduce capacity or close several refineries. If all refiners follow the METI ordinance, a total of around 800 kb/d of refinery shut-downs could be expected, It could also effectively lead to more refining capacity closures in the long run as refiners will unlikely be able to justify investment in upgrading all of their refineries in the current business environment. Since 2010, about 425 kb/d of capacity has been shutdown, with closures at JX Group, Idemitsu and Showa Shell. As an alternative to refinery closure or restructuring, JX Group has signed a joint venture agreement with Chinese's CNPC for its 115 kb/d Osaka refinery. As most of the refined products are exported to China, the Osaka refinery is to be excluded from the METI ordinance.



In 2013, Cosmo Oil announced that it will close its 140 kb/d Sakaide refinery by July 2013, and by 2014, TonenGeneral will scrap a combined 105 kb/d or 16% of its refining capacity. TonenGeneral will shutdown a 67 kb/d crude distillation unit at its Kawasaki plant and a 38 kb/d crude distillation unit at its 170 kb/d Wakayama refinery. We estimate that by 2018, total Japanese refining capacity will decline to 4.0 mb/d from 4.6 mb/d in 2012.

Elsewhere in the region, **South Korean** refiners have invested recently mainly to improve their conversion yields. GS Caltex has just brought on stream its fourth heavy oil upgrader with a capacity of 53 kb/d, while a 40 kb/d hydrocracker is planned for 2016 at SK Energy's Incheon refinery. In 2012, South Korean refiners ran at very high utilisation rates, driven by strong exports. Oil products emerged in 2012 as the country's highest export earner, as the country's four refiners — SK Innovation, GS Caltex, S-Oil and Hyundai Oilbank — exported more than half their refined products.



TRENDS IN GLOBAL OIL INVENTORIES

Summary

- Increases in global storage capacity over the medium-term are likely to be driven by factors including: the further development of independent storage at coastal terminals to facilitate long haul crude and product trade, the building of government strategic storage, refinery expansions and the de-bottlenecking of logistically important points to smooth the transport of crude to markets.

- Construction and filling of the remainder of Phase 2 and planned Phase 3 sites of the Chinese SPR will be both the single largest stockpiling and storage capacity construction project over the medium-term, potentially buttressing Chinese demand.

- North American storage capacity expansion has lagged the increase in supply which has resulted in periodic bottlenecking and subsequent widening of North American regional crude price differentials. A number of expansion projects are due to be commissioned over the medium term at these pinch points, which should help alleviate these problems.

- Other notable capacity expanions will be driven by the Middle East, in conjunction with new refinery projects, and Other Asia, as many states there make efforts to increase commercial and government storage against a backdrop of booming demand.

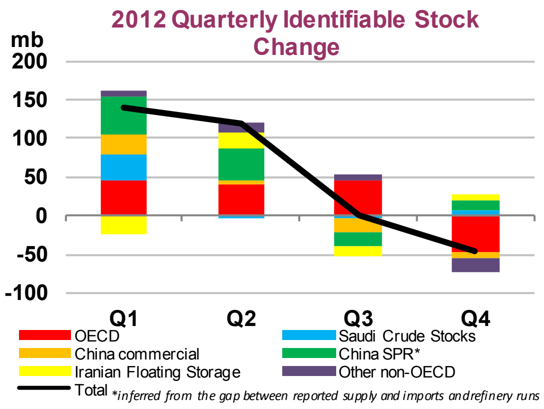
Shifts in inventory positions are typically associated with fluctuations in the futures curve. Market participants are incentivised to build up their stockholdings when the curve is in contango (*i.e.* when deferred barrels trade at a premium to prompt supply); conversely, market signals associated with backwardation (the reverse curve structure) encourage destocking. Shifts in storage capacity, however, are driven by other factors, and so the last few years, during which global crude and product markets have rarely been in contango, have nevertheless seen an explosion in storage capacity growth. That global boom in the construction of new storage capacity is expected to continue over the medium term with various expansion projects both in OECD and non-OECD economies.

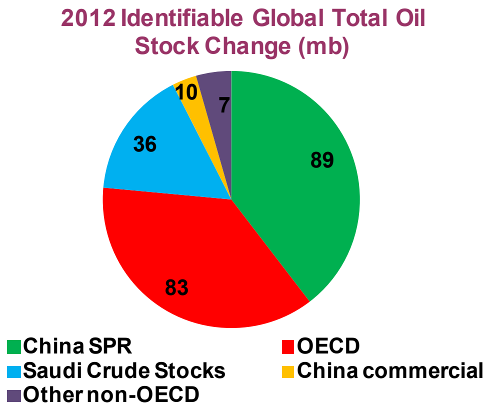
There are a number of drivers which have made, and will continue to make, capacity expansion attractive. Foremost among them are the changes in the global oil trade map discussed in the 2012 *MTOMR*, with more oil heading to Asia and long-haul trade set to increase over the medium term. These opportunities have encouraged independent storage operators to expand their tank farms and lease new tanks to traders which use them to build and break bulk in locations such as Europe, the Caribbean, the Middle East and OECD Asia Oceania. Additionally, these independent installations are strategically important to states, for instance Chinese companies lease tanks outside of its territory to expedite their imports. Secondly, increases in non-OECD Asian strategic storage require the building of new capacity, be it in caverns or above-ground tanks. Thirdly, capacity, notably in North America, is struggling to catch up with the rapid increase in domestic supply. To smooth the transport of these oils to market requires the expansion of tank farms at pipeline intersections and rail terminals. Finally, refinery expansions in China, the Middle East and Latin America can all be expected to increase storage whether it be feedstock tanks to supply the refineries, product storage within the complex or at terminals to aid the export of products.

Global overview

At end-2012 OECD total oil inventories stood at 4 213 mb, a rise of 72 mb from a year earlier and broadly level with the five-year average. Due to a lack of data, absolute inventory levels and stock changes for the non-OECD group as a whole are not known. Fast-rising non-OECD demand for oil products, and even faster growth in non-OECD refinery throughputs, are fuelling considerable interest from market participants and other stakeholders in better-quality and more comprehensive non-OECD stock data. Despite substantial advances in data collection orchestrated under the Joint Organisations Data Initiative, including better data for amongst others, Saudi Arabia and South Africa, and third party datasets pertaining to China, Singapore and Russia, much progress remains to be made.

In Table 1 of our monthly *OMR*, non-OECD stock changes implicitly fall under the *Miscellaneous to Balance* line item, along with smuggled oil, oil traded or exchanged in the 'black market', pipeline fill and refinery fuel consumption. The *Miscellaneous to Balance* may also reflect overstated supply or understated demand. Over 2010-11 this item averaged -500 kb/d signalling a stock draw. At the time of writing, this item averaged 1 mb/d over 2012, pointing to a stock build, but remaining subject to revision pending the receipt of official annual data. If confirmed, and assuming that supply and demand data remain unchanged, the *Miscellaneous to Balance* would notionally imply an unreported annual build of 366 mb, dwarfing the 72 mb reported build in the OECD. Much of that notional increment can be traced to 1Q12, when the build averaged 1.6 mb/d, suggesting a 146 mb quarterly increase. Chinese strategic stock building likely accounts for a large share of the build. Although China refrains from publicly commenting about either the capacity or the fill rates of its Strategic Petroleum Reserve (SPR), the latest tranche of its SPR may account for a 89 mb (250 kb/d) stock build in 2012 (see *Recent and Future Developments in Chinese Inventories*). Other indications from JODI suggest that Saudi crude stocks built by 36 mb over 2012 while data for several other major non-OECD countries such as South Africa, Thailand and Brazil indicate that stocks rose by an aggregated 5 mb.





It is also worth noting that over 2012 the stock change in global floating storage held for speculative purposes is assumed to be zero following the persistent backwardated structure of crude and product futures markets. During 2012, floating storage therefore resulted from logistical issues such as the filling up of land-based storage. The largest component of this has undoubtedly been Iran, where stock changes have been included under *Miscellaneous to Balance* since data are unofficial and indicative. Nonetheless, information from ship brokers suggests that these volumes actually drew year-on-year by 12 mb.

Together the stock changes for select non-OECD countries outlined above account for 142 mb of the 2012 *Miscellaneous to Balance* figure, which leaves a notional 223 mb unaccounted for. The remainder of the figure may be partly attributed to builds in fast-growing economies such as India, Malaysia and Indonesia, where demand increased and/or new refinery capacity was commissioned, or in large producers such as Russia, Iran, Iraq and Venezuela, where data inventory data are unreported or unreliable.

If information on non-OECD storage capacity – whether nameplate or working – is often lacking, details on who leases storage capacity are even harder to come by. This scarcity of information greatly complicates the analysis of stock movements. For instance, it can be difficult to ascertain whether inventory gains in, say, the Caribbean reflect bulk building by Chinese companies looking to aggregate small parcels of crude or residual fuel oil until they can be loaded onto a VLCC and shipped economically to long-haul destinations, pre-positioning of crude by suppliers or exporters like Saudi Arabia near US refiners, or speculative stockpiling by trading companies.

OECD Americas

Storage capacity and inventory levels in the OECD Americas are closely watched for two main reasons: Firstly, the provision of granular weekly and monthly inventory data by the US Energy Information Administration (EIA) and secondly the large-scale expansion of storage and transport capacity required by the LTO and oil sands supply revolution. Because the US is unique in providing detailed weekly reports on its oil inventories, more is known about US stock movements than about inventory trends anywhere else. As a result, US inventory movements have traditionally been treated as a proxy for, or early indicator of, global inventory changes. Meanwhile, the surge in LTO and oil sands production in the US and Canada has created storage and transportation bottlenecks which in turn have caused those new crude grades to trade at historically wide discounts to internationally traded crude. Developments in storage and transport infrastructure capacity are thus particularly market-sensitive and closely tracked by participants. The on-going construction of new shell capacity in the US and Canada is deemed necessary to alleviate logistical issues at pinch points such as pipeline and rail terminals, production hotspots and refining and petrochemical sites.

Storage concerns in Canada chiefly focus on the ability of Albertan producers to store their production in the event of a logjam on southbound crude pipelines. Over the past 12 months, these pipelines have frequently been filled by US production, notably from North Dakota, which has necessitated Canadian producers either to put their oil into short-term storage or accept prices well below US benchmark WTI. Indeed, so far in 2013 West Canadian Select has traded at an average discount of USD 24/bbl to WTI and on occasions this discount has widened to as much as USD 40/bbl. Although there are plans to expand pipeline capacity to the West Coast (See '*Pipeline construction: spotlight switches to the Atlantic Basin'* in October 2012 *MTOMR*), those plans, if approved, would not be completed until the end of the forecast period at the earliest. The availability of extra storage capacity would thus be of significance to Canadian producers to cushion themselves against bottlenecks in the US pipeline system, even if rail capacity out of Alberta continues to be expanded. However, it will likely not totally alleviate these discounts since they will still reflect rail or pipeline transportation costs to different US regions.

Most of the storage capacity expansion triggered by new Albertan production is occurring, and will continue to occur, at pipeline hubs. Storage capacity at production sites is limited, with tanks typically containing only a couple of days worth of bitumen production and storage at upgraders containing a similar amount. In contrast, pipeline intersections, notably at Hardisty and Edmonton, have developed into the predominant storage hubs. Pipeline companies such as Enbridge, Kinder Morgan and TransCanada have led this drive and share ambitious plans to further expand capacity. Enbridge added 7.5 mb of above ground storage in 2009 at Hardisty while further plans by TransCanada and Gibson Energy will add close to 1.5 mb there by end-2014. Kinder Morgan is currently adding 3.6 mb at Edmonton due for completion in 4Q13 with a further 1.2 mb due on line by 4Q14, which will take the terminal's capacity to 9.4 mb. However, with 300 kb/d of Albertan production due by end-2014 and a further 225 kb/d of Bakken production due over the same period, and even accounting for an expected increase in rail shipments, it remains to be seen whether this storage expansion will be sufficient to protect producers from the shifts in differentials versus benchmark US crudes.

The impact of surging domestic supplies on US stockholding

US total liquids supply rose by 1.4 mb/d in 2010-12 and is forecast to increase by more than 2.7 mb/d over 2012-18, with crude contributing 70% of the increment. Furthermore, Canadian supply is projected to grow by 1.3 mb/d over the medium-term, mostly from Alberta. Such a production surge is resulting in large-scale requirements for new transportation and storage infrastructure. US storage capacity has already gone through a major growth spurt, and there is more to come for both crude and products including at production sites, storage hubs and refineries.

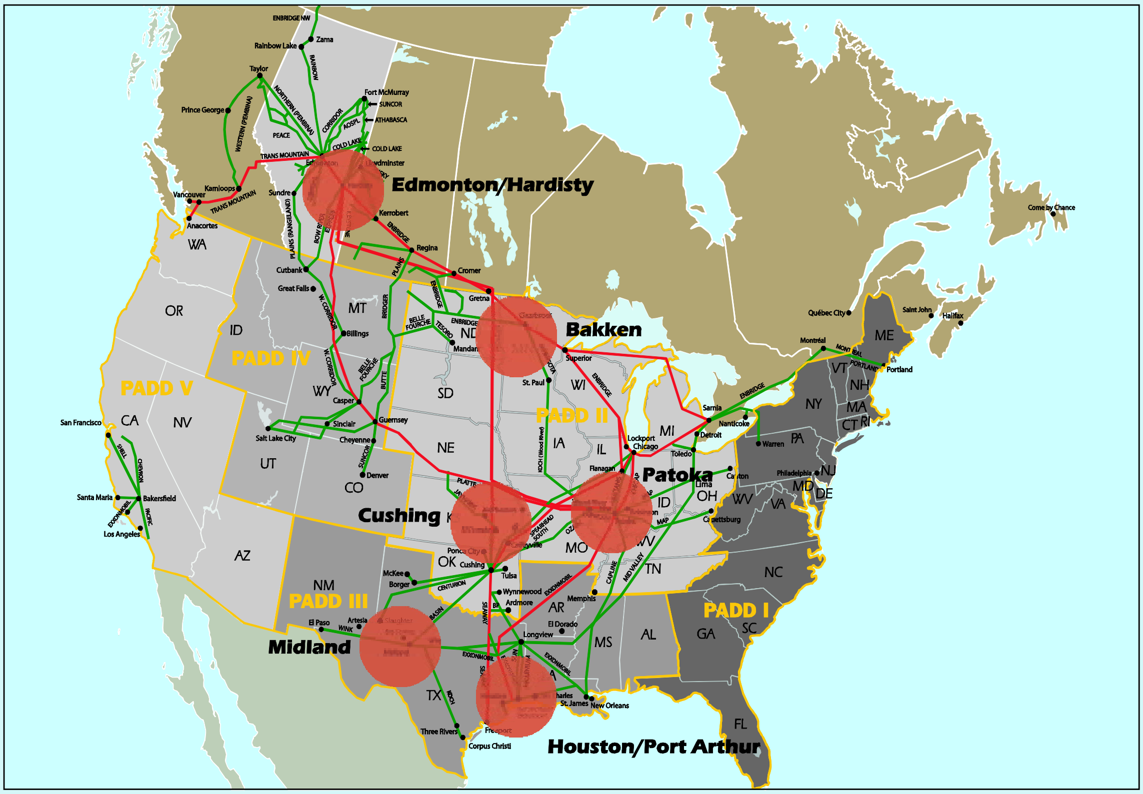
Much has been written about transport logistics failing to keep pace with US supply growth and midstream service providers struggling to move crude past pipeline bottlenecks. What has been described in less detail is the scramble to expand storage capacity at those pinch points. In the US, with onshore producers generally storing only limited volumes at production centres, logjams have arisen at pipeline hubs and rail terminals. Although stock levels at storage hubs such as Midland, Texas and Cushing, Oklahoma (the delivery point of the benchmark West Texas Intermediate contract) have attracted much attention, the capacity of these hubs required estimation. The EIA sought to address this problem in 2010 when it launched a twice-yearly survey of working and shell storage capacity for crude and products by Petroleum Administration for Defence District (PADD), including a breakout of capacity at Cushing. With a large proportion of incremental North American supplies making their way into the US Midcontinent, the survey shows that working crude storage capacity in PADD 2 (the Midwest) jumped to 122 mb by September 2012, a gain of 24 mb or roughly 25% since the first such survey two years earlier. Storage at PADD 2 refineries actually inched down by more than 1 mb while capacity at tank farms surged by 25 mb.

Over the same period, the survey also indicates that working capacity at Cushing increased by 18 mb. This capacity is currently assessed at 64 mb. Reports indicate that the current main capacity owners are Plains All American Pipelines (19 mb), Enbridge Energy Partners (19 mb), Magellan (12 mb) SemGroup (7 mb) and Blueknight Energy Partners (6.6 mb). Although information is patchy, anecdotal reports suggest that most of the major operators are planning to expand capacity.

While storage capacity expansions may be required for operational reasons or blending purposes, capacity users may also seek to take advantage of shifts in price differentials between Cushing and points at the receiving end of the pipelines flowing from it. Forecasters project that the premiums of LLS and Brent over WTI will diminish over the medium-term following the commissioning of new pipeline projects to evacuate crude southwards. Whether this will be enough to temper the rapid expansion in storage capacity remains to be seen. Short-term opportunities for capacity owners to react to market imbalances will remain, however.

The impact of surging domestic supplies on US stockholding (continued)

Location of Logistical Bottlenecks in North America



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: The base of this map is sourced from the Canadian Association of Petroleum Producers

Recent domestic North American supply growth has been concentrated in light, tight oil (LTO) (approximately 40 API and higher), Canadian syncrude (31.4 API) and bitumen (11 API). While these grades have traded at a wide discount to waterborne LLS and Brent over the past couple of years, and thus have been attractively priced for US refiners, including them in a refinery's crude slate can be tricky. Many US Gulf Coast refiners have invested heavily in deep-conversion capacity that lets them process heavy imported grades, which typically traded at a discount to lighter ones. Thus it is not economical for them to process the lighter syncrude and LTO. This has incentivised market participants to invest in blending equipment at storage facilities and produce blends that more closely resemble the refiners' desired crude slate. Although there are no comprehensive data on the scale of blending in the US Midcontinent and Gulf Coast regions, anecdotal reports indicate that many owners of tanks at Cushing have installed blending equipment allowing them to blend LTO with heavier Canadian grades. Additional reports have indicated that light crudes evacuated from the Midcontinent to the Gulf Coast either by pipeline, rail or even barge have been combined with heavier Venezuelan crudes to produce medium-light grade, refinery specific crudes to improve refinery margins.

The demand for blending services has undoubtedly put storage capacity operators who offer these services and have their facilities configured for either batch or inline blending at a distinct advantage to those who do not. Despite the extra cost involved in installing blending equipment in tanks, it is highly likely that future projects at hubs, which receive different types of crude, notably at Cushing and on the Gulf Coast, will be capable of blending crudes *i.e.* small tanks to hold the unblended crudes and larger tanks in which to blend them together.

The impact of surging domestic supplies on US stockholding (continued)

While domestic US supply has been soaring, demand has been contracting and US net import requirements have fallen. When measured in days of net imports, US total oil stocks have risen even more steeply than volumetric stock gains would suggest: Over 2011-12, US commercial total oil stocks jumped by a steep 44 mb, but US total oil stocks surged to 175 days of net imports, from 161 days previously. In the US as elsewhere, changing market realities on the ground may be an opportunity to rethink the adequacy of legacy strategic reserve arrangements initially set up under markedly different circumstances. Currently the US Strategic Petroleum Reserve (SPR) contains 696 mb of mainly light, sweet crude oil, equivalent to about 76 days of net imports (not including oil held at commercial facilities, which when taken together with segregated SPR oil brings total US oil reserves 1.1 billion barrels higher). Previous to the IEA's Libya collective action, in the summer 2011, the SPR stood at 727 mb. Following a 30.6 mb release undertaken as part of the collective action, the decision was taken not to restock.

For the period 2012-18, this *Report* forecasts that US demand will contract by 420 kb/d to 18.2 mb/d, even as total liquids supply rises by 2.7 mb/d to 11.7 mb/d. Net imports are thus projected to drop further, to 6.5 mb/d, which would bring the SPR, if it remained at current levels, to 107 days of net imports. Commercial stocks could also be expected to rise in tandem with soaring supply which would further call into question the cost/benefit balance of holding the SPR steady. Should a US policy review lead to a reduction in the size of the SPR or a swap of light crude for heavy, considerations would have to be made to avoid adverse or destabilising market effects, especially if the release is limited to the US market.

Although the spotlight has been on crude storage, there have been some important recent developments in product storage, especially in PADD 1. As refinery capacity in PADD 1 has decreased in recent years, related storage has also declined. Refined product working storage capacity in PADD 1 stood at 44 mb by September 2012, 8 mb lower than 12 months previous. Moreover, over 80% (6.5 mb) of the closed storage capacity previously held either motor gasoline (3.4 mb) or distillate fuel oil (3.1 mb). Accordingly, on an absolute basis, PADD 1 gasoline and distillate fuel oil inventories stood lower by 5 mb and 13 mb, respectively, at end-2012 compared to a year earlier. PADD 1 demand is experiencing structural changes, distillate fuel oil is losing its market share as cheaper natural gas is increasingly becoming the heating fuel of choice, thus fewer distillate fuel oil inventories are required during the winter. In contrast, PADD 1 gasoline inventories look tighter, despite sluggish gasoline demand growth, on an absolute level gasoline demand has held up better than distillate fuel oil.

Looking towards the medium term, it is likely that storage capacity in PADD 1 could rebound. Recently, Ergon, operators of a 22 kb/d refinery at Newell, West Virgina announced a USD 28 million investment to expand storage to an as-yet unstated level. Additionally, Buckeye has announced plans to refurbish 1.3 mb of inactive product (mostly gasoline) storage capacity and construct 1 mb of new capacity at its Perth Amboy, New Jersey terminal. These investments should go a long way to increasing supply chain flexibility in the US Northeast.

Many new operators have recently entered into the US midstream sector. These operators have been attracted by numerous factors, including the opportunities arising from domestic crude and product price disparities and, as elsewhere, the ability to have market visibility *i.e.* to gain information on a market through direct participation in it.

These prospects have attracted international oil traders to invest in US infrastructure. Notably, Vitol has invested in both US crude and product storage under its VTTI JV in which they hold a 50% share. The company recently inaugurated the 3 mb Canaveral product storage terminal, which will distribute supplies along the eastern seaboard. Such independent infrastructure projects in diverse locations can improve the energy security of a country by providing a more robust and flexible supply chain.

The impact of surging domestic supplies on US stockholding (continued)

Another group of relatively new entrants to the US midstream sector are master limited partnerships (MLPs). Due to tax incentives, these companies have generally been spun off from integrated oil companies and control the midstream assets (distribution networks and tank farms) of the previous company. Examples of these partnerships which control significant storage capacity, notably in the mid-continent, include; Buckeye, Nustar, Enterprise Product Partners, Plains All American Pipeline, Blueknight Energy Partners, Rose Rock Midstream, Kinder Morgan Energy Partners. Although these companies have experience in the storage sector they do not necessarily behave in the same manner as an integrated oil company would function. As with other new operators, their earnings benefit from volatility since they have no exposure to the upstream or downstream markets and thus profit from regional and temporal price disparities.

OECD Europe

Storage in OECD Europe has recently undergone a number of changes in response to evolving market conditions, including the rationalisation of regional refining capacity and the growth in long-haul trade between the Atlantic and Pacific Basins. Regional capacity has steeply contracted since the 2008 financial crisis and is expected to drop further, reducing regional demand for crude storage. But demand for product storage appears to be rising as refining capacity drops even faster than demand, and the role of Northwest Europe is growing as a global storage hub supporting long-haul global trade.

Between 2008 and 2012, no less than 3 mb/d of European refinery capacity was shuttered. This *Report* estimates that a further 900 kb/d of European refining capacity is at risk of closure. However, net capacity losses only paint a partial picture of the sector's restructuring. Additionally, a number of refining assets have moved from the hands of traditional refiners to those of trading houses. That is the case of Petroplus's 100 kb/d Antwerp, Belgium and 68 kb/d Cressier, Switzerland refineries, which were acquired by Vitol, the Swiss-based trading house. Additionally another Swiss-based trader, Gunvor, purchased two more Petroplus facilities: the 110 kb/d IBR Antwerp, Belgium plant and the 110 kb/d Ingolstat, Germany facility. Far-flung foreign oil companies have also acquired European refineries or stakes in European refining companies. Those include Indian refining giant Essar, which bought the 300 kb/d Stanlow, UK plant; Lukoil which bought into a number of refineries including plants on Scilly (320 kb/d ISAB refinery) and in the Netherlands (190 kb/d Zeeland refinery) and Petrochina which invested in the 210 kb/d Grangemouth, UK and 210 kb/d Lavéra, France facilities.

Some of the refineries which have been closed have been turned into storage terminals and now handle the import and distribution of imported products. An example of this is the 160 kb/d Flandres refinery at Dunkuerque, France which was shuttered by Total in 2010 and turned into a distribution tank farm with approximately 9 mb of storage. On balance, European refining capacity has contracted even faster than demand, and will likely continue to do so in the next five years. As a result, IEA data indicate that over 2010-12 OECD Europe has increased its product imports from Russia, the US, the Middle East and India, amongst others.

At end-2012 OECD European commercial inventories of crude, NGLs and other feedstocks stood 33 mb (8%) lower than at end-2007. Despite the reduction in regional refining capacity, over the same period, product inventories stood 26 mb (5%) lower. While somewhat counter-intuitive, given the widespread assumption that reductions in refining output cause cuts in total feedstock storage requirements but not in product storage, this decline may be explained by the steep 1.9 mb/d decline in European demand over the period. The effect of this demand decline is apparent when examining inventories on a days of forward demand basis. Indeed, at end-2012 total commercial refined products actually covered four more days than at end-2007.

It has been argued that persistently backwardated markets have tempered product restocking in the region. Considering that new independent companies which have replaced IOCs as refinery operators, do not have the same exposure to profitable upstream assets that IOCs can cover downstream losses (such as holding oil against a backdrop of backwardation), it could be argued that they would temper stock building in such circumstances. However, this does not seem to be the case, rather persistently underwhelming European demand has been the primary driver for the low regional stock levels. This is illustrated when examining days of forward cover, at end-2012 total products covered 40.1 days, one day above a year earlier and above five-year average levels. However, on absolute levels were 29 mb lower than the previous year, demonstrating that stock holders do not need to keep inventories at historical levels.

Examining European storage at an aggregate level masks its internal geographic disparities. For example, while the French storage sector is in decline, storage in areas such as the ARA region (Amsterdam, Rotterdam and Antwerp) and the south of Spain, is booming as these regions utilise their logistically beneficial locations to facilitate the increase in long-haul trade, especially between the Pacific and Atlantic Basins.

Looking forward, with regional refining capacity expected to be further rationalised, both commercial and government stock holders are likely to move towards holding a greater percentage of refined products as compared to crude and other feedstocks. For government stock holders this poses a number of issues. Firstly, if the government only holds crude oil stocks, this will likely not be sufficient to insulate themselves against local, regional and global market disruptions considering that reduced local refinery capacity would be unable to take up crude released as part of a stock release. Secondly, if countries are forced to hold finished oil products to cover their obligation then it becomes more expensive on a per barrel basis. It is something the EU commission has also considered in view of it requiring member countries to hold stocks equal to or above 90 days of average net imports or 61 days of average daily consumption (whichever is greater).

Another important issue concerning storage going forward concerns the construction of capacity in relation to changing crude supplies for example, a planned crude terminal at the Polish port of Gdansk to be completed in 2015 will include a 4.4 mb tank farm and will facilitate the import of seaborne Russian crude supplies. This facility is strategically important given that Eastern European IEA member states have recently been forced to adapt to lower Russian pipeline supplies after it became more profitable for Russian producers to ship oil via the new Ust Luga terminal in the Baltic and eastwards via ESPO.

A further impact of the transition towards more seaborne Urals shipments at the expense of pipeline flows is the proposed development of a Urals trading hub at Rotterdam to assist the grade in becoming a regional benchmark crude at the expense of Brent which is suffering from a declining physical supply. Indeed, this is a much-mooted goal of the Russian administration. Construction of Tank

Terminal Europoort West is earmarked to begin in 2013 and the proposed 19 mb of shell capacity would make it the single largest oil storage construction project in the region over the medium-term horizon. Two thirds of the capacity is earmarked for crude and the rest for products, likely gasoil and fuel oil. Together these two products accounted for 85 % of Russia's total product exports in 2012.

Elsewhere in the region the ARA area is one of the world's largest independent storage sites and Northwest Europe's key trading hub distributing products throughout the region and down the Rhine into central Europe. Companies operating in the region include global players Vopak, Oiltanking, Rubis, Nustar, Vitol and Mercuria. Despite the decrease in regional demand, the hub is currently experiencing healthy growth due to changing product flows. First, European refining rationalisation has necessitated the import of products from long-haul origins. Second, after long-haul trade between the Atlantic and Pacific basins has increased rapidly over recent years and the hub is a favoured location for bulk breaking. As such, stock levels in the hub have risen steadily over the past 15 years.

ARA oil storage capacity is expected to expand by 12 mb in the next few years from close its current level of 150 mb (including petrochemical feedstocks and vegetable oils used for biofuels). Capacity is assessed to have expanded by approximately 8 mb over 2012, largely after the completion of Vopak's 7 mb Westpoort Phase 2 project. Capacity expansions in the next few years will likely be led by the 5.7 mb Quay 510 project in Antwerp.

OECD Asia Oceania

Storage developments in this region are being driven by Japan and Korea which, despite undergoing refinery rationalisation, are positioning themselves as logistically important oil hubs for Persian Gulf producers as they export more crude to satisfy surging import demands of Asian economies undergoing economic growth, notably China. This *Report* (see '*Crude Trade* Section') expects that despite taking extra oil from elsewhere, notably Russia, China will maintain its Middle Eastern crude imports at over 2 mb/d over 2012-18.

For instance, in 2011, faced with the prospect of refinery rationalisation, the Japanese administration decided to sign a commercial agreement to hold 3.8 mb of Saudi Arabian crude at Okinawa, which would be owned by Saudi Aramco but which the Japanese government would have the right to use in an emergency. This accord permitted the Japanese administration to utilise spare storage capacity on its national territory while simultaneously reducing its crude oil purchasing budget. Such agreements are attractive to producers since they allow them to break bulk in the region, affording them extra flexibility in supplying lucrative Asian markets. A similar agreement was made with the UAE's ADNOC in 2009 to store 3.9 mb of crude; this was renewed in 2012 but it was not disclosed whether volumes had changed.

Since 2004 the Japanese administration has been progressively switching its SPR from heavier to lighter grades in line with increased demand for lighter products. This process is ongoing, with Japan selling 4.4 mb of medium and heavy crudes via tender in 1Q13, the administration is likely to replace these with lighter grades at a later date.

In Korea, the S-Oil refinery operated by, amongst others, Saudi Aramco stores approximately 2 mb of crude, contrary to popular belief these holdings are for use within the refinery rather than as a strategic stockpile. Moreover, similar strategic commercial agreements to those in Japan are in place with Middle Eastern producers; notably, ADNOC stores 6 mb in Korea.

Additionally, the Korean government is trying to develop a North Asian oil hub in the south of the country around the ports of Yeosu and Ulsan, which are both capable of handling VLCCs, to take advantage of trading opportunities arising from the increasing import needs of non-OECD Asian economies, notably China. A storage terminal has already been completed at Yeosu with 5.4 mb of crude capacity and 2.8 mb for products. In a further phase a 28 mb tank farm will be constructed with a current completion data of 2020 envisaged.

Other Asia

Many emerging Asian economies have plans to develop government and commercial oil storage. Notably, some of these states have released plans, sometimes tentative ones - for building strategic storage over the medium term, summarised in the Table below.

Current and Future Stockpiling in non-OECD ASEAN Countries

Country	Government Held	Industry Obligation	Stockholding Target
Cambodia	no	yes	current obligation on industry = 30 days of consumption
Vietnam	yes	yes	total stocks = 16 mb, rising to 34 mb in 2015, equivalent to 73 days of consumption in 2015
Thailand	no	yes	current obligation on industry = 36 days, strong commitment to achieve 90 days of consumption in future
Myanmar	yes	yes	620 kb by 2025 including 180 kb product SPR.
Laos	no	yes	current obligation on industry = 15 days of consumption, rising to 30 days in 2020
Indonesia	no	yes	current obligation = 23 days of consumption, planning to strengthen national stockholding system
Phillipines	no	yes	current obligation on importers = 7 days of supply, current obligation on refineries = 15 days of supply

India has been investigating the possibility of developing strategic reserves for much of the past decade. Initially, the administration decided to establish a 110 mb petroleum reserve in two phases. Stage One, consisting of underground salt caverns at three sites with a combined capacity of 39 mb of crude oil, was due to be completed by end-2011. Current reports indicate that construction is well behind schedule. A recent trade report indicated that the first of these caverns located at Permude in Mangalore on India's west coast is now due to be completed in 1H13, with the other two caverns tentatively slated for completion over 2014-15. Once these are completed, there is no timetable for filling them, which could cost about USD 4 billion at current market prices. If filling of the Permude cavern was spread over six months, it would add an approximate 100 kb/d to Indian crude requirements. Information on the 71 mb Phase Two is elusive. However, capacity is likely to include both caverns and above-ground tanks and be operated on a commercial basis. Several plans have been mooted by the Indian administration, including introducing an obligation on industry and inviting foreign commercial partners to run the facilities.

Several other non-OECD ASEAN economies have in place tentative plans to increase stock holdings which will involve the construction of new shell capacity. Currently, the Philippines, Vietnam, Thailand, Myanmar and Indonesia are discussing the possibility of creating government held stocks.

Others instead are planning to put in place obligations on industry, or to increase existing ones. Thailand and Vietnam have made strong commitments to achieve stock levels comparable with the 90 days of net imports held by IEA countries while, initially at least, other administrations are planning to reach lower levels of under 50 days of consumption or net imports. Whether the oil will be held by government or industry, such policy-driven storage expansions will necessitate the construction of new storage capacity.

Recent and future developments in Chinese inventories

China is the location of the largest tranche of government storage capacity addition over the medium term while it will also likely increase its commercial storage in tandem with refinery expansions. In 2001, China's Tenth Five-Year Plan (2001-05) called for the establishment of a national strategic petroleum reserve (SPR) of 500 mb to be completed in three progressive phases by 2020. China is also projected to witness the largest growth in global refinery capacity, potentially adding over 4 mb/d by 2018. These new refineries will require the commissioning of significant storage capacity to hold operating stocks of both crude and products.

Since China treats the SPR as a state secret, information on capacity increases, fill rates and stock level remains elusive. What seems clear is that the monthly data published in *China Oil, Gas and Petrochemicals* (*China OGP*) do not include changes in government stocks. Therefore, the recent filling of a tranche of China's crude strategic petroleum reserve has not been directly captured by these data. Indeed, *China OGP* data suggest that over 2012 commercial crude holdings built by less than 3 mb, or less than 10 kb/d. Given that 2012 annual average refinery runs grew by 410 kb/d compared to a year earlier, forward run cover actually fell by 1.3 days during the year. This seems unlikely considering 330 kb/d of refining capacity came on stream in 2012 which would require significant operating inventories. As highlighted in the *OMR* dated 11 April 2013, *China OGP* data did not include the build up of crude operating stocks at the 500 kb/d of refinery capacity commissioned so far in 1Q13.

The IEA estimates total Chinese crude stock changes based on the 'gap' between refinery throughputs and net imports plus production data. Over 2012, this averaged 200 kb/d, which could suggest an annual build in SPR stocks or unreported commercial stocks of up to 89 mb. In February 2012, we estimated that 79 mb barrels of SPR capacity was expected to be completed over 3Q11 to 4Q12.

After the filling of SPR Phase-1 sites was completed in 2008, China is now in the midst of filling its Phase-2 sites. Over 2012, it is likely that a large volume of the oil which went into the SPR came from Kazakhstan, since one completed Phase-2 site is located at Dushanzi in Xinjiang province. Regional refiners preferentially take crude via a line running from the Kazakhstani border city of Alashankou. FSU export data indicate that flows through the Kenkiyak – Alashankou pipeline rose by 100 kb/d between 2Q12 and 3Q12 suggesting that this site was being filled. Other crudes which likely filled the SPR were sourced from Saudi Arabia, Iraq and Russia with this oil likely heading to Lanzhou and Tianjin.

Going forward, it now appears that the completion of Phase-2 storage capacity has been delayed and will now likely not occur until 2015, a significant revision to our previous forecast of end-2013 completion. Reports indicate that construction delays coupled with high prices has not incentivised rapid stock building. Uncertainties abound regarding the timing of the successive phases of SPR development, whether individual sites belong to Phase 2 or Phase 3, and whether specific storage sites under construction will be used for commercial or strategic inventories. Additionally, many regional administrations have expressed interest in holding stocks but it is uncertain whether these are included under the national SPR plan. Estimates for Phase-2 capacity now range from 169 mb (our original estimate) to 300 mb. Our estimate has been revised upwards to 245 mb, although the caveats outlined above still have to be considered.

Recent and future developments in Chinese inventories (continued)

What is likely is that some additional Phase-2 sites will be commissioned in 2013, which, when considering the probable spare capacity at sites completed in 2012, could buttress China's demand for crude over the year. If China completes tanks at Huizhou and Huangdao, which many observers believe likely to be completed in 2013, this could average over 56 mb, or 150 kb/d of incremental oil 'demand', over 2013.

Locations for Chinese Strategic Petroleum Reserves

This map is without any 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.

Recent reports have also circulated concerning the construction of Phase-3 capacity. These tanks are the final part in China's SPR plan and should add between 170 mb and 205 mb of storage which would take the overall capacity of the SPR to over 500 mb by 2020. Current reports indicate that sites earmarked for development include Wanzhou, Yangpu and Caofeidian, although information concerning capacity at individual sites remains elusive. There are no firm dates concerning the completion of Phase-3, but considering the construction timeline of Phases 1 and 2, if a project breaks ground in 2013, it will likely not be ready for filling until towards 2015. A recent report in *China OGP* stated that Yangpu in Hainan province 'is expected to become China's major oil and gas storage base by 2015' which would suggest that a tranche of Phase-3 capacity there will be operational by this date. Assuming Chinese demand of nearly 13 mb/d and net imports of 8.4 mb/d by 2020, a 500 mb SPR would cover approximately 60 days of net imports. Therefore, assuming Phases 1 and 2 aggregate to 348 mb, this would leave Phase 3 capacity at 152 mb.

Recent and future developments in Chinese inventories (continued)

Chinese Strategic Petroleum Reserve Sites

(million barrels)

	Operator	Location	Capacity	Status	Completion
Phase 1	**Sinopec**	Zhenhai, Zhejiang	32.7	filled	3Q06
	Sinochem	Zhoushan, Zhejiang	31.4	filled	4Q07
	Sinopec	Huangdao, Shandong	20.1	filled	4Q07
	CNPC	Dalian, Liaoning	18.9	filled	4Q08
Total			**103.1**		
Phase 2	CNPC	Lanzhou, Gansu	18.9	filled	1H11
	CNPC	Dushanzi, Xinjiang	18.9	filled	1H11
	Sinopec	Tianjin Phase 1	20.1	filled	2012
	CNPC	Jinzhou, Liaoning	18.9	under construction	2013
	CNPC	Shanshan, Xinjiang	39	filling, under construction	2012-2013
	CNPC	Jintan, Jiangsu	15.7	under construction	2013
	CNOOC	Huizhou, Guangdong	31.4	under construction	2013
	Sinopec	Huangdao, Shandong*	18.9	under construction	1H14
	Sinopec	Zhanjiang, Guangdong	44	under construction	2015
	Sinopec	Zhoushan, Zhejiang	19	under construction	2013
Total			**244.8**		
Phase 3	Sinopec	Tianjin Phase 2	20.1	planned	2015
	unknown	Wanzhou, Chongqing		planned	2020
	Sinopec	Caofeidian, Hebei	38	planned	2020
	Sinopec	Yangpu, Heinan		planned	2020
	CNPC	Rizhao, Shandong		planned	2020
	CNPC	Daqing, Heilongjiang		planned	2020
	CNPC	Yunnan province		planned	2020
	CNPC	Qinzhou, Guangxi*		planned	2020
Total			**152.1**		
Total SPR			**500**		**2020**

* some estimates indicate these sites as commercial storage

Source: Reuters, OGP, CNPC, Energy Intelligence, IEA Estimates

The general consensus that the SPR will be filled entirely of crude could be misleading. Reports have begun to circulate that China could be planning to include refined products as part of the SPR. It is still assumed that crude will make up the bulk of the reserve but in order for China to respond to short-term disruptions, additional product storage would be required. However, how China could hold these stocks remains open to debate. Rather than being held physically by the administration, they could instead be held by industry at the request of the government, similar to the minimum stockholding obligation on industry utilised by many IEA member countries.

Beside the SPR, an important recent development concerns some of the latest investments made by Chinese national oil companies in storage facilities outside China and especially their willingness to invest in the independent storage sector. In 2012, Sinopec announced the construction of a 2.6 mb facility in Indonesia and an investment deal with Vesta Terminals for 1.6 mb of European storage capacity. Additionally, CNPC holds a 35% stake of the 14 mb Universal Oil Terminal in Singapore. These investments are likely intended to help the company increase its trading presence in these markets. With China set to become a large product exporter towards the end of the forecast period, these sites could become a vital cog in Sinopec's distribution network. Additionally, PetroChina recently expressed an interest in buying the cross-Panama Trans-Isthmian pipeline together with its 14 mb of storage facilities. This would facilitate the shipment of Venezuelan crude to Pacific markets, currently expected to exceed 600 kb/d by 2018. PetroChina also leases approximately 2.5 mb of capacity at the BORCO terminal in the Caribbean which it also uses to build bulk cargoes of Venezuelan crude for onward shipment to China aboard VLCCs.

Middle East

Saudi Arabia unsurprisingly has the largest crude oil storage capacity in the Middle East, apart from limited storage at production sites, the bulk of its storage is located at its export terminals, including the 33 mb tank farm at Ras Tanura, the country's largest facility. Recent developments have seen Saudi Aramco add a significant tranche of capacity when it commissioned its Jubail 400 kb/d JV refinery with Total. The construction of such a refinery generally involves the construction of three types of storage, firstly crude storage to help manage feedstock flows, secondly on-site storage of products at the refinery and thirdly product storage at nearby terminals to support exports. Information suggests that the JV was responsible for the crude and product tanks at the refinery while Vopak and Sabic are jointly constructing over 2 mb of product and chemical storage at the Jubail terminal to be completed in early 2015.

It is likely that the Jubail project was the largest recent addition to regional clean product storage capacity over the past few years. Saudi Arabia will also be the likely centre of regional clean product storage capacity growth over the medium term, with tanks at other planned refineries, such as the Yanbu and the Jizan complexes, each 400 kb/d, due to be commissioned over the forecast period. In addition, the UAE and Iraq are slated to add close to 450 kb/d and 200 kb/d of new refining capacity by 2018, respectively, which will require the addition of extra crude and product storage tanks.

Although Iraq is projected to experience the highest production capacity expansion in the region (+1.57 mb/d over 2012-18), it is not projected to see a large expansion in storage capacity. To a certain extent it is anticipated that SOMO and its commercial partners will concentrate their efforts on improving infrastructure, of which storage capacity is a vital component. In order to meet their ambitious export targets it is critical that storage at the southern Fao terminal be expanded. Currently, crude is stored in eight tanks at the terminal which reportedly cover just two days of production, approximately 5 mb. An additional 16 storage tanks are expected to be added which should take total storage there to 8 mb over the forecast period.

Iranian storage expansion plans linked to previous refinery expansion projects have been restricted by the current US and EU sanctions. Despite recent statements by the government to the contrary, it is highly unlikely that Iran will build any new land-based storage capacity while under sanctions. It is reportedly having problems sourcing steel after long-time supplier Ukraine was unable to maintain supplies under threat of sanction. Therefore it is highly likely that if the current stalemate over its nuclear programme is prolonged, the fate of Iranian infrastructure will be similar to that of Iraq under sanctions in the 1990s when tanks fell into disrepair as spare parts and steel could not be easily obtained. Iran's land-based crude storage is currently assessed at 36 mb. However, as noted in previous monthly *Reports*, Iran also stores oil at sea. Iranian floating storage is estimated to have peaked at 32 mb in July 2012 as NITC faced a logistical dilemma of maintaining supplies to existing customers while also finding a home for production volumes. This situation relaxed towards the end of the year as new VLCCs were delivered by Chinese shipyards. Consequently, floating storage decreased to a relatively low 20 mb by year-end. As sanctions continue, and with benchmark crude prices in backwardation limiting speculative floating storage, it is likely that Iran will drive changes in global floating storage in 2013.

Going forward, another major development in the Middle East concerns the Fujairah terminal in the UAE, currently undergoing expansion. This terminal, one of the world's largest bunkering centres, is home to tank farms for both crude and products operated by a number of companies including independents Vopak and Vitol, national oil company SOCAR and the government of Fujairah. However, following the 2012 inauguration of the Abu Dhabi Crude Oil Pipeline (ADCOP), it is becoming a significant crude exporting terminal with crude storage at the port having expanded to 8 mb. The ADCOP is strategically important since it bypasses the Straits of Hormuz choke point and this importance has grown with Iran periodically threatening to close the straits in retaliation for US and EU sanctions against it. With this in mind, it is likely that crude storage will continue to be expanded there over the medium-term.

The Fujairah government is also promoting increasing the emirates' importance as a regional trading hub. Going forward, there are numerous projects for the expansion of clean and dirty product storage at the terminal with many of these being operated by independent storage companies such as Vopak and VTTI. Current estimates put total oil storage capacity there at 55 mb at end-2012. It is expected that this could rise to 84 mb by end-2014 if all projects such as those being planned by Gulf Petrochem, ADNOC and SOCAR are realised.

Much current discussion amongst the bunkering community concerns the growing importance of cleaner burning, cheaper LNG as an alternative bunker fuel to fuel oil and marine gasoil. With LNG typically stored at dedicated hubs, if bunker demand for LNG were to take off, as some forecasters are predicting, it would necessitate the construction of new dedicated storage sites at bunkering hubs such as Fujairah, Rotterdam and Singapore. Although it would remain to be seen whether this would add to or replace existing oil product storage capacity at these hubs.

Outside of OPEC, the biggest potential regional development is likely to be in Oman which is planning to construct a second crude oil storage hub at Ras Markaz. Currently, it is in the initial planning stages but if approved, it could begin operation in 2017. Reports indicate that the hub could store 20 mb of crude oil, making it the largest terminal in the Middle East. Since this capacity would dwarf Oman's domestic crude production, projected at 830 kb/d in 2018, tanks would likely be leased to other Middle Eastern producers who could be attracted by strategic storage outside the Straits of Hormuz and also independent traders.

Africa

Information concerning developments in African inventory levels and infrastructure remain elusive. With the region being short of refining capacity there are a large number of coastal terminals in the region geared to importing and storing products, especially gasoline and middle distillates. Since many governments and national oil companies are unwilling to invest in these terminals, preferring to focus instead on production, rising import requirements have attracted many independent companies to the region.

Recently, VTTI opened East Africa's largest diesel and gasoil terminal in Kenya with capacity to store approximately 680 kb to supply the regional market including landlocked countries Uganda, Rwanda and Burundi. This terminal supplements the existing Kenyan government-operated Kipevu Oil Storage Facility (KOSF) which has been straining to meet regional demand, leading to numerous transport fuel shortages over the past couple of years. The only other import and storage terminal in the region is located at Dar es Salam with a capacity of over 600 kb. However, there are numerous local small-scale fuel depots in inland Tanzania, Kenya and Uganda.

In West Africa, the refining sector also has similar problems to East Africa. However, despite the presence of OPEC members Angola and Nigeria, the focus is on storage capacity to facilitate the import and distribution of refined products. Many recent developments have concerned the construction of new tanks capable of storing LPG in response to burgeoning local demand as it replaces wood burning stoves for cooking in the residential sector.

In North Africa, the focus of storage turns to crude oil with large regional producers Algeria and Libya leading the way. Although the latter is still rebuilding infrastructure following the 2011 civil war, many of its damaged terminals are now up and running, albeit with limited storage capacity. For example, Ras Lanuf, once Libya's largest crude export terminal and site of the country's largest refinery, suffered extensive damage during the civil war with a large number of tanks destroyed, reports now suggest that the refinery is running at reduced rates with one of the constraints being the limited available storage while crude oil exports are similarly restricted due to lack of storage at the terminal. The most significant African storage terminals from a global crude trade perspective are those at Sidi Kerir (21 mb) and Ain Sukhna (10 mb) at each end of the SUMED pipeline in Egypt. Despite more Middle Eastern oil being shipped East of Suez and the ongoing sanctions precluding EU states from importing Iranian crude, these sites are strategically important to OECD buyers of especially Saudi and Iraqi crudes.

Former Soviet Union

Considering the size of the region, very little accurate information is available concerning storage capacity and stock levels in the region. Significant storage capacity for both crude and products is located at refineries, pipeline junctions and seaborne and rail export terminals with smaller storage facilities located close to production sites and at distribution terminals. Information concerning export terminals is the most widely available. Over recent years Russia has developed both the Ust Luga and Kozmino ports, the former handles both crude and products while the latter focuses on crude only. Crude storage at Ust Luga is approximately 2.5 mb while product storage is roughly 4.2 mb. Main storage along the ESPO system is located at Skovorodino (1.9 mb) and Kozmino (3.1 mb) with smaller tank farms located at pumping stations. With tentative plans in place to expand shipments via the system to over 1 mb/d and for extra crude to be supplied via the pipeline to a new Rosneft refinery on the Pacific coast, it is highly probable that extra capacity could be built out before 2018, although exact volumes remain elusive.

Russia will not be launching any new ports over the medium term, rather existing terminals will be expanded. By far the largest player in Russian crude oil infrastructure is state-owned monopoly Transneft, which operates the majority of crude export terminals and associated storage. In 2011, Transneft was reported to control 125 mb of total liquids storage capacity dispersed throughout Russia. In contrast, most product terminals are owned by private and independent companies including Lukoil, Gunvor and Novatek. It should be noted, however, that the ownership structure of many terminals in the region is opaque and fragmented, often with one company owning the storage, another owning the supply infrastructure and a third owning the berths.

In the Southern region, the focus is moving from crude exports, which have fallen following the launch of ESPO and Ust Luga, to product shipments, throughputs of which are expected to increase in the coming years as refineries are expanded and upgraded. Therefore, in order for terminals to comfortably handle extra volumes, storage capacity will have to be constructed. One example of this is the proposed

Novorossiysk trans-shipment terminal, a JV between Gunvor with the Novorossiysk Commercial Sea Port, which will handle fuel oil from regional refiners and require the construction of a 750 kb tank farm.

Locations of Recent Russian Storage Expansions

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.

Outside of Russia, the main developments regarding crude storage will concern the doubling of the capacity of the CPC pipeline requiring the construction of six additional storage tanks at the CPC marine terminal close to Novorossiysk (total 3.8 mb). This project will increase storage capacity at the terminal to 6.3 mb. Additionally, a new dirty product terminal will be launched at the Ukrainian port of Feodosia which will likely be used to ship Kazakh-produced product since less and less crude is now being shipped through the port. As part of the plan the existing tank farm will be expanded to approach 2.5 mb.

Latin America

The Latin American storage sector is undergoing sweeping changes. These include aggressive capacity expansion plans in the Caribbean, to help facilitate regional crude and product trade in the wake of refinery closures. This restructuring of the sector is giving private independent companies a much more important role than they previously had. Crude trade is centred on the distribution of Latin America's regional crude production, which is both traded within the region and exported elsewhere. Latin American economies are also increasingly short of refined products, which necessitates the import of large volumes, mostly from the US, while there is also some significant intra-regional trade. In 2012, the EIA estimated total Caribbean storage capacity to be approximately 130 mb operated by diverse companies including traders, refiners and NOCs. Moreover, there are plans afoot to expand storage at a number of sites, including, but not limited to, Buckeye's 8 mb expansion project at the BORCO terminal in the Bahamas to take total capacity at the facility above 29 mb.

Current Capacity at Carribean Oil Storage Terminals
(million barrels)

Country	Name of Terminal	Port/City	Capacity	Operator
Aruba	Aruba	St. Nicolaas	12.0	Valero
Bahamas	BORCO	Freeport	21.5	Buckeye
Bahamas	South Riding Point	South Riding Point	6.7	Statoil
Curacao	Curacao Terminal	Bullen Bay	17.8	PDVSA
Bonaire	BOPEC	Rincon	12.0	PDVSA
St. Eustatius	Statia	Orange Bay	13.0	NuStar
Puerto Rico (US)	Yabucoa	Yabucoa	4.6	Buckeye
St. Lucia	St. Lucia	Cul De Sac	10.0	Hess Oil
Trinidad & Tobago	Petrotrin Point Fortin	Port Fortin	3.6	PETROTRIN
Trinidad & Tobago	Petrotrin Pointe-a-Pierr	Pointe-a-Pierre	4.1	PETROTRIN
Virgin Islands, US	Hovensa	St. Croix	32.0	Hess Oil / PDVSA
Total Capacity			**137.3**	

Since shutting down in the last couple of years, both the 350 kb/d HOVENSA refinery in St Croix, Virgin Islands, and Valero's 235 kb/d Aruba refinery have been operated as storage terminals, as import demand from Latin American economies and burgeoning product exports, notably gasoline, from the US have made these viable. In 2011-12, plans to shut down several US East Coast refineries indirectly affected the Caribbean storage market, dramatically boosting the strategic value of Caribbean tank farms as key pegs in a fast-transforming US East Coast product supply chain. NuStar and Buckeye, two of the main players in the Caribbean storage market, are also leading participants in the East Coast storage and product distribution industry. Buckeye's BORCO expansion project goes hand in hand with its plan to expand storage capacity at New York Harbor and increase the two systems' integration.

Information on stocks movements and storage usage at Caribbean tank farms tends to be closely guarded. But some news can be gathered from trade press and corporate reports and shipping data. Indian refiner Reliance Petroleum, which has recently grown in importance as a gasoline supplier to the US East Coast, has been identified in trade reports as a large lease holder at the BORCO terminal, where it has been reported to store gasoline. Shipping data indicate that product arrives on Panamax sized carriers before being bulked into larger cargoes for export to the US East coast on Aframax tankers. PDVSA leases a vast amount of capacity on Curacao and Bonaire, which it uses to build up cargoes of crude and residual fuel oil for export to other Carribbean locations, the US Gulf Coast, China and Malaysia. In addition, PDVSA owns a 50% stake in the currently-shuttered HOVENSA St Croix refinery in the US Virgin Islands. The refinery was closed in early-2012 with the aim of turning it into a product storage and distribution terminal. Virgin Islands laws do not allow this, however, as the plant's free-trade zone status is bound to its being maintained as a working refinery. At the time of writing, HOVENSA was reportedly seeking a buyer for the plant. While HOVENSA's high energy costs have left it at a competitive disadvantage to US Gulf Coast refineries, which have greatly benefitted from the US shale gas boom and their access to low-priced natural gas, the possibility of running US LTO at the St Croix plant could enhance its value. US laws allow the plant to both run US crude and economically ship products back to the US East Coast or other US locations, as the US Virgin Islands are exempt from both the US export ban and the Jones Act.

Another lease holder of storage tanks in the region is state-owned Petrochina. The company reportedly leases tanks at terminals in the Bahamas (BORCO), St Eustatius and St Lucia to aggregate smaller cargoes of mainly crude for shipment to China on VLCCs.

Outside the Caribbean, land-based storage expansion is expected in Brazil towards the end of the medium term, in tandem with refining capacity expansions. Although the planned capacity of the new plants has been announced (+1.6 mb/d), information on tank farms is more elusive. Brazil is also expected to increase crude production by over 900 kb/d over the forecast period as Petrobras ramps up production at its offshore pre-salt reserves. However, in an effort to decrease costs, the company is constructing an offshore storage terminal which will handle a large proportion of incremental production. Currently, Agencia Nacional do Petroleo (ANP) estimates Brazilian crude storage capacity at close to 34 mb. Over the medium-term it is likely that Petrobras will continue to lease VLCCs for floating storage as it periodically has over the past two years.

CRUDE TRADE

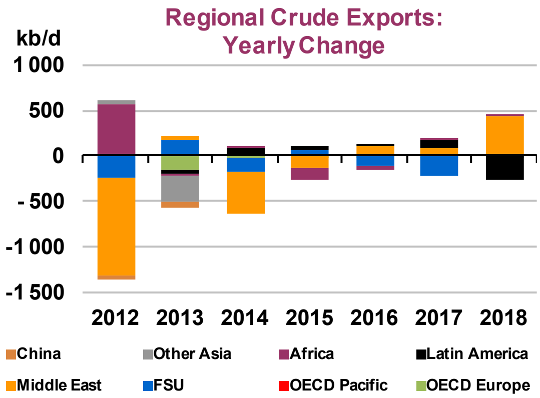
Summary

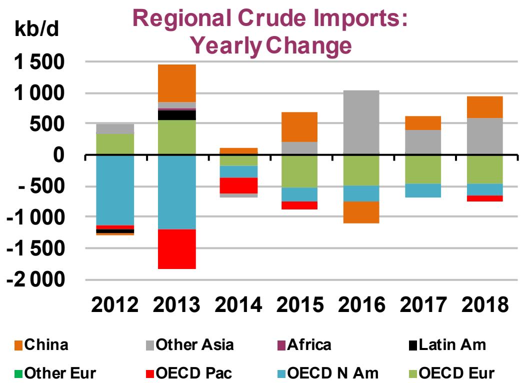
- The global trade in crude oil and marketed condensate is projected to fall by 0.9 mb/d to 32.4 mb/d over 2012-18 as rising North American supply reduces the region's import requirement.

- Non-OECD economies will increase their share of global imports so that by 2018 they will surpass that of the OECD, accounting for 51% (16.5 mb/d) of total imports. This reflects diminishing imports by North America, lower refinery demand in Europe and OECD Asia Oceania and increasing demand in China and Other Asia.

- North American net imports are forecast to contract by a significant 2.2 mb/d to 3.4 mb/d by 2018. Shipments to the region from the Middle East, Africa and Latin America are forecast to contract by 980 kb/d, 840 kb/d and 320 kb/d, respectively.

- Rising inter-regional trade in refined products will more than offset falling crude trade, as more oil is refined close to the wellhead and exported as products.





Overview and methodology

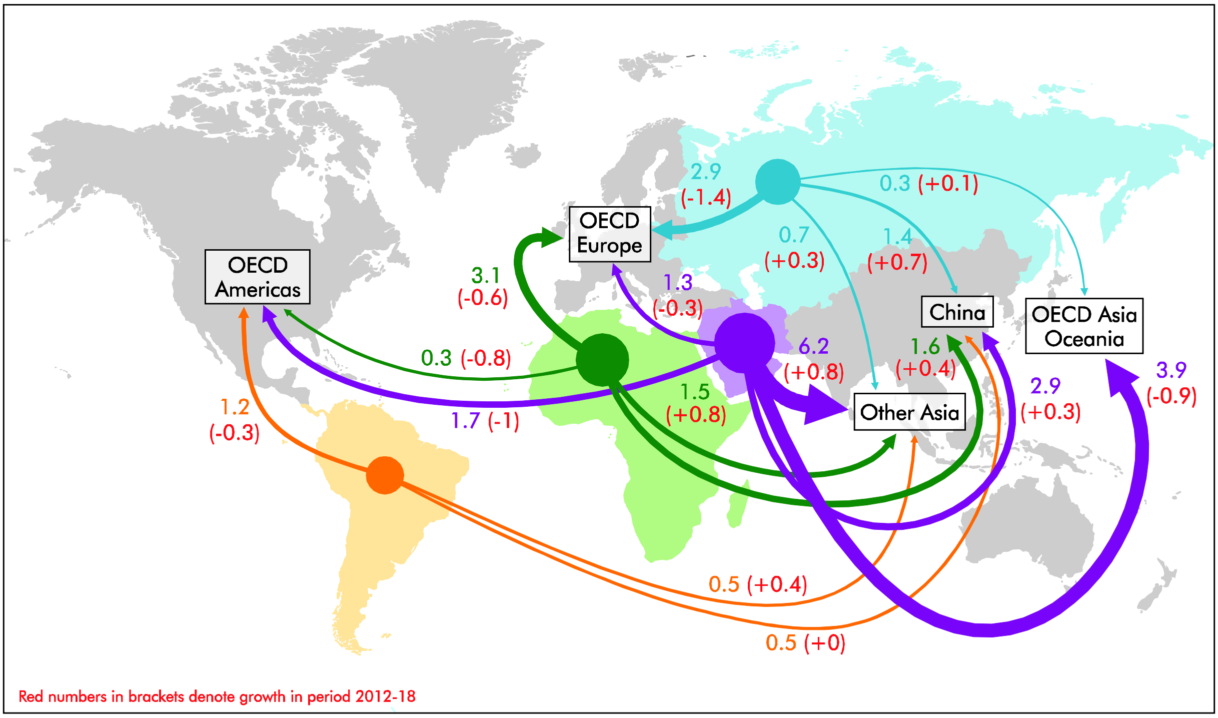
Inter-regional global trade in crude oil and marketed condensate has been modelled as a function of projected oil production, demand growth and refinery utilisation, with incremental supplies being allocated based on expectations of refinery capacity expansion. In this edition of the *MTOMR* we focus on surging North American supply and its impact on the global oil trade map, including its effect on the region's net imports, the composition of the region's remaining crude import slate and the expected market outlets of crudes backed out of the region.

The global trade in crude oil is projected to decline by 0.9 mb/d to 32.4 mb/d in 2018 from 33.3 mb/d in 2012, equivalent to a compound average annual decline of 0.5%. This is a continuation of the forecast presented in the October 2012 *MTOMR,* where global trade was estimated to fall by 1.6 mb/d (0.8%) over 2011-2017. Not only is crude trade seen 0.7 mb/d lower in 2017 at 32.2 mb/d, but our forecast has been lowered by an average 0.5 mb/d over 2011-2017. This follows upward revisions to our North American supply outlook (+ 350 kb/d in 2017) and downwards adjustments to the forecast for other regions. Refinery capacity in producing regions is also seen higher and moving closer to the wellhead, extending a trend identified in previous editions of the *MTOMR*. As producer countries boost refining capacity and process more of their domestic oil at home, inter-regional trade in refined products is expected to grow and more than offset the decline in crude trade.

Over the medium-term the Middle East will consolidate its role as the key long-term swing supplier, exporting 16.3 mb/d in 2018, only 30 kb/d below 2012 after new supply is forecast to ramp up in Iraq (1.6 mb/d), the UAE (0.7 mb/d) and Saudi Arabia (0.4 mb/d). The region's share of global crude trade is set to increase over the forecast from 49% in 2012 to 50% in 2018. Despite its exports falling from 7.0 mb/d to 6.9 mb/d over the forecast against a backdrop of rising domestic demand and lower production prospects in Algeria, Africa is set to retain its role as the world's number two exporting region, accounting for 21% of the export market by 2018, level with 2012. FSU exports are expected to remain hot-on-the heels of Africa, accounting for 19% of total trade throughout the forecast despite a 240 kb/d drop in shipments to 6.1 mb/d in 2018. Latin American export volumes are projected to remain stable over the forecast at 2.1 mb/d, its market share therefore remains at 7%.

Crude Exports in 2018 and Growth over 2012-18 for Key Trade Routes

(million barrels per day)



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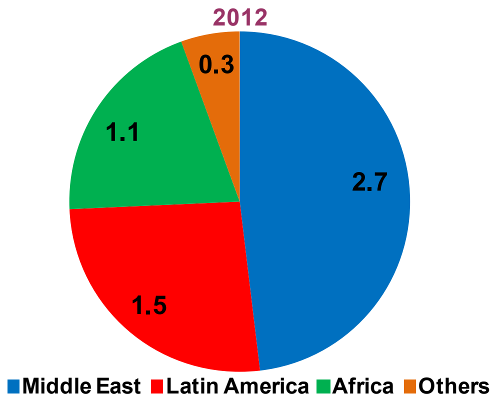
Note: Excludes intra-regional trade.

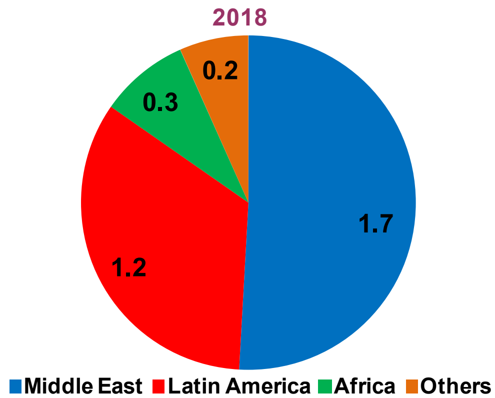
North America: surging domestic supply redraws the global oil trade map

Over the forecast period the single largest development in the oil trade landscape will be the continuing surge in US and Canadian supplies. Indeed, 2.7 mb/d of incremental US supplies, notably of light, tight oil are due over 2012-18 with Canada expected to contribute an extra 1.3 mb/d of mainly heavy Albertan oil and syncrude. For the purpose of this modelling exercise, this *Report* assumes no relaxation in the ban on US crude exports over the medium-term. It also assumes that, save for some limited exports of East Canadian oil to Europe, there will not be a large increase in Canadian shipments to destinations outside North America. All told, North American imports of crude oil are seen to decline by a further 2.2 mb/d over the forecast, reaching 3.4 mb/d in 2018 as domestic refiners, notably in the Gulf Coast, adjust their configuration and crude slate to handle more domestic supplies. Another assumption in the model is that regional refiners will run their hydrocrackers at approaching 100% of capacity due to their suitability for taking light oils and turning these into light products such as gasoline and naphtha. With a number of exceptional licenses expected to be granted for the export of US crudes to Canada by refiners such as Valero, it also assumed that Canadian hydrocrackers, having access to US light crudes, will run at high utilisation rates throughout the forecast to maximise their distillate yields. Finally, we assume that large volumes of US NGLs will be transported northwards by both rail and pipeline for use as diluent in the transport of bitumen back to the US, thus backing out condensates currently imported from elsewhere, notably the FSU.

Origin of North American imports in 2012 and 2018

(million barrels per day)





In 2012 the main sources of North American crude imports were the Middle East (2.7 mb/d, 48% of total imports), Latin America (1.5 mb/d, 26%) and Africa (1.1 mb/d, 20%) but in 2018 imports are set to drastically change. By 2018, all regions exporting to North America will see their imports fall as North American net imports fall. However, these falls will not be equally shared either on a market share or volumetric basis.

Much US Gulf Coast refining capacity has been configured to process heavy Latin American crudes and thus the market for light crudes is relatively limited. However, there are several options to facilitate the processing of light crude which refiners could adopt. Firstly, they could be expensively reconfigured. However, current company plans indicate operators do not intend to pursue this option. Secondly, light crudes can be blended with heavy grades to produce refinery-specific medium-light crude blends which refiners can economically run thus keeping margins buoyant. Presently, anecdotal reports suggest this appears to be the option favoured by US refiners. Moreover, this means that imported light and medium-light crudes will be increasingly backed out of the region as more and more US LTO and light

Canadian syncrude is evacuated southwards to the Gulf Coast as de-bottlenecking projects are commissioned. These projects include, but are not limited to, the reversal of the 400 kb/d Seaway and 225 kb/d Longhorn pipelines and the 200 kb/d expansion of the Permian Express pipeline.

Historically the US was West Africa's largest export market peaking at 2.7 mb/d in 2007, after which shipments have steadily declined. This trend will accelerate given that the majority of African crude imports to the US have been light or medium-light streams such as Nigerian Bonny Light (35.1 API) and Brass River (40.1 API) and Angolan Girassol (29.7 API) and Cabinda (32.2 API). Indeed, by 2018, North American imports of African crudes are estimated at 300 kb/d, 850 kb/d lower than in 2012 which would mean that only 6% of regional imports would be sourced from there. Another 'nail in the coffin' for African imports into the US concerns imports into PADD 1. Refiners there now have access to railed supplies of LTO from Bakken. Indeed, EIA data are beginning to show a decrease in African imports into this region with this trend likely to be maintained throughout the medium term as rail shipments continue to increase (see *Railing crude in North America*).

In contrast, and partly due to the refining requirements for heavy crude set out above, and despite a 320 kb/d fall in imports, Latin American producers are set to see their share of North American imports rise by 8% to 34% by 2018. Declines will likely be concentrated in lighter streams such as Colombian Cuisiana (42.6 API) which will be backed out by LTO. Meanwhile, imports of heavier Venezuelan and Colombian grades, will likely retain a share of the Gulf Coast market as they are blended with LTO at refineries and storage terminals in the region.

However, an important caveat remains over the medium term which could significantly alter the dynamics of intra-North American trade. If approved by the US administration, the Keystone XL pipeline would be capable of transporting 700 kb/d of Albertan bitumen to Cushing, Oklahoma and onward to the Gulf Coast. Since these volumes would be cheaper than seaborne crudes due to lower transport costs, they would theoretically back out heavy imports from Latin America and the Middle East. The current understanding is that this long-delayed pipeline, if approved in summer 2013, would not start-up until 2015 at the earliest. Although the *MTOMR* model assumes that almost all Canadian production will remain in the region, the approval of the project could bring forward investments in oil sand projects which would add upside to our production forecasts.

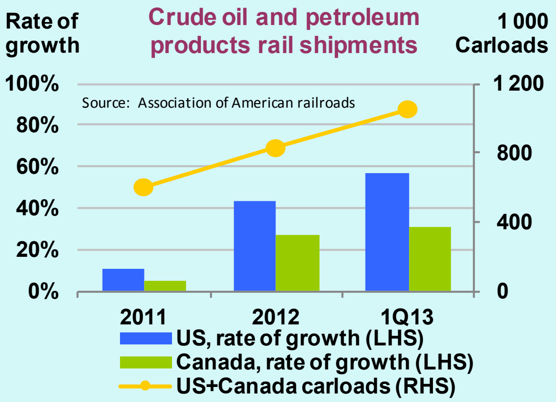
The Middle East will also increase its market share from 48% to 51%, and consolidate its position as the main exporter to North America. However its exports there are set to plunge by 980 kb/d to 1.7 mb/d in 2018. Its retention of market share reflects US Gulf Coast refiners' need for heavy oil and the long-established ties between Middle Eastern producers and US refiners, in particular Saudi Aramco's share in the Motiva joint venture with Shell.

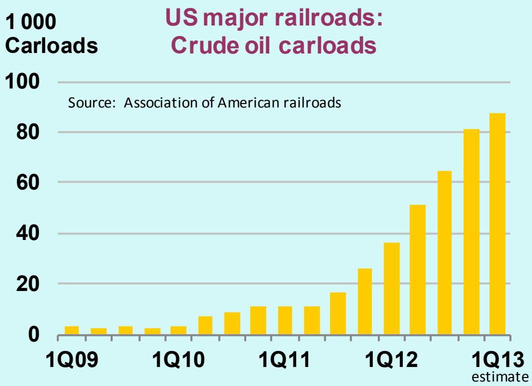
Railing crude in North America

The next five years will see a further increase in US rail shipments of liquids, thus continuing the unexpected revival of rail as a critical means of transporting petroleum in the US. Rail emerged three years ago as a way to avoid the congested midcontinent pipelines and move Bakken crude to refineries on the US Gulf Coast. Instead of being just a temporary measure, the current resurgence of rail appears to have staying power. As the development of LTO resources evolves so will rail transport patterns, with increasing volumes of crude moving by rail to refineries on the East and West Coasts. Rail transport is likely to retain a key role within the broader menu of transport options available to the oil market, thanks in part to its distinctive attributes: flexibility, relatively low investment and permitting costs, and the relatively short lead time.

Railing crude in North America (continued)

North American rail shipments of crude oil and petroleum products increased at an impressive pace. US crude oil carloads increased from about 11 000 (20 kb/d) in 2009 to over 230 000 (450 kb/d) in 2012, according to the figures of the Association of American Railroads. The most recent 1Q13 figures imply that the volume of crude oil shipped by rail in the US is about 680 kb/d, which corresponds to almost 10% of total US crude oil production. Canadian crude and petroleum products rail shipments growth is also strong (+150% in 2012, from 2009 levels). Rail shipments of crude and petroleum now represent 5% and 9% of total rail shipments in the US and Canada, respectively, an increase from 2% and 6% in 2009.





Note: US Major Railroads (Class I freight railroads) include BNSF Railway, CSX Transportation, Grand Trunk Corp, Kansas City Southern Railway, Norfolk Southern Combined Railroad Subsidiaries, Soo Line Corp, and Union Pacific Railroad. They also include US operations of the major Canadian railroads CN and CP.

Railroads and the Bakken revolution

Since the beginning of the LTO boom in the Bakken formation of North Dakota in 2010, rail has carved out a unique niche as a prime means of moving oil to markets. The use of rail began largely as a way to move Bakken production to the US Gulf Coast. Without sufficient pipeline capacity to connect Bakken to refining centres, Bakken faced transportation constraints similar to those at Cushing, and thus sold at significant discount to coastal grades such as Light Louisiana Sweet (LLS). These price discounts provided an incentive for Gulf Coast refiners to capture the arbitrage opportunity between Bakken and LLS by moving Bakken south via rail. According to data from the North Dakota Pipeline Authority, over 2012 rail takeaway capacity in the Williston Basin of North Dakota, where the Bakken formation is located, increased year-on-year by almost 400 kb/d to 660 kb/d in 2012, compared to pipeline capacity growth of only 50 kb/d.

However, rail movements are no longer limited to the Gulf Coast. Growing volumes of Bakken production are finding their way to the Atlantic and Pacific Coasts *via rail*. In fact, rail shipments of Bakken to Gulf Coast refiners could decline as Bakken faces growing competition from other crudes such as Eagle Ford and Permian. With less favourable economics of sending crude to Gulf Coast, more Bakken volumes will be available to move eastward and westward. Several rail offloading facilities have been completed on both coasts, and several more are under development (see *Tables* section). Access to competitively priced Bakken crude oil could support struggling refiners on the East Coast that have historically relied on relatively expensive Brent-linked imports.

As logistics struggle to keep up with fast-rising production capacity, rail seems here to stay for the medium term. Railroad capacity continues to be developed even as pipelines are added. Up to 600 kb/d of incremental pipeline shipping capacity is expected to come online from the Williston Basin by 2015, compared to 2012. Over the same period, 350 kb/d of loading rail capacity is planned in the Williston Basin.

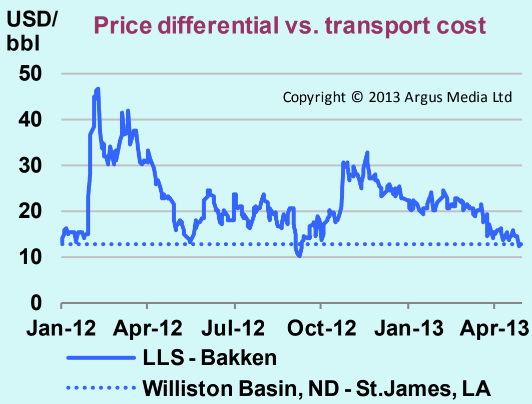
Railing crude in North America (continued)

Offload rail capacity is also on the rise, including gains of 750 kb/d on the East Coast and over 700 kb/d on the West Coast, with West Coast currently lagging 1+ year behind the East Coast in terms of year-to-year capacity additions. In the Gulf Coast itself, 1.2 mb/d of incremental offload capacity for light crude is being developed (that accounts also for inland rail-to-barges transloading facilities). However, that could be served less by Bakken volumes as a ramp-up in production (+ 1 mb/d by 2015) in the Niobrara and the Permian Basin will suffer from insufficient pipeline capacity too. Several projects are already in place or under way for shipping LTO from these sites (+0.8 mb/d by 2015). A list of onload and offload projects by regions is included in the *Tables* section.

Lastly, LTO transport is not the only driver of rail traffic growth. The growth in shale oil and gas production has increased the reliance on the rail network to deliver oilfield services and other materials needed for the drilling process including water, sand, fracking fluids, and steel.

Economics of crude oil rail transport

While rail shipments of oil are by no means unprecedented, in the recent past their role had been mostly limited to that of a stop-gap, temporary measure pending the building of pipelines. What makes the recent rail boom unique is its unprecedented scope and speed, and that it is unlikely to be totally phased out completely even after the many pipeline projects currently under development come to fruition.



Rail transport offers the flexibility to target the most profitable markets, relatively shorter construction lead times and lower construction costs than pipelines, and fewer regulatory hurdles. Despite all these advantages, shipping crude by rail is more expensive than by pipelines. Future rail movements will thus require a sufficiently large price differential between inland crude at the production or gathering site and crude benchmark grades near refinery centres. In fact, one would expect the crude price gap between two locations to migrate to the marginal cost of transport (whether by rail or by pipeline) between those points. As the volumes of Bakken crude being moved to the Gulf Coast recently increased, the differential between LLS and Bakken crude at Clearbrook, Minnesota narrowed (despite Clearbrook not being the best indicator of Bakken anymore because of the large volumes that are being railed), close to the level of the cost of transporting crude from North Dakota to Louisiana, USD 12.75/bbl.

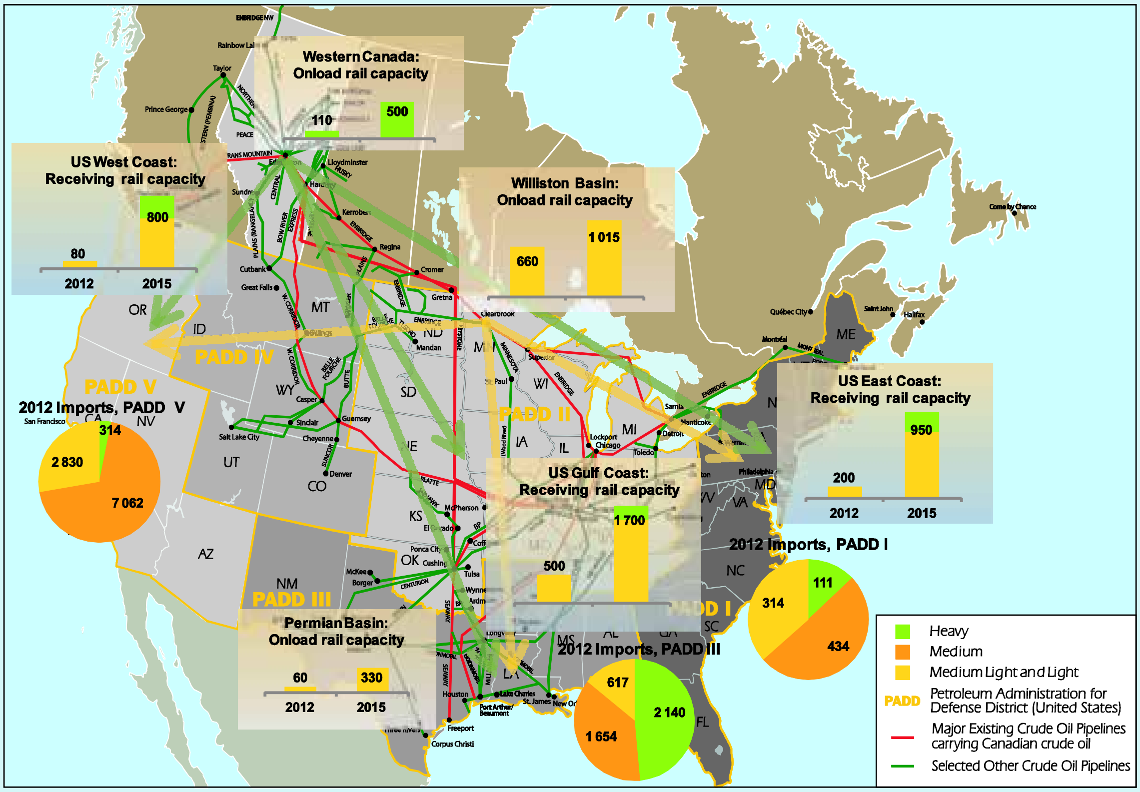
Rail options for Canadian bitumen

Rail is also becoming a major means of crude transportation in the Canadian province of Alberta. We anticipate that loading capacity there may reach 500 kb/d by 2015, from an estimated 200 kb/d shipping capacity today.

We do not, however, expect rail boom on a similar scale than in case of US LTO as most Alberta crude production is in the form of bitumen, rather than LTO. Shipping bitumen by pipeline is more complex than shipping light crude oil, as the former typically has to be thinned with diluents to flow through the pipe, usually in a ratio of 70:30. Moreover, as bitumen is denser and more viscous than light oil, more energy is needed to move it through the pipeline. In contrast, moving bitumen by rail requires less diluent – only about 15% to 20% – or no diluent at all.

Railing crude in North America (continued)

LTO and bitumen rail flows and rail terminal capacities in North America



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Note: The base of this map is sourced from the Canadian Association of Petroleum Producers.

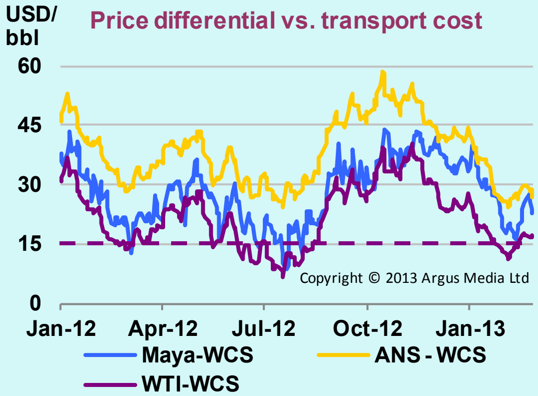
Despite the potential cost savings on diluent, there are additional costs involved in moving bitumen by rail, however. In the case of a 85:15 blend (so-called railbit), insulated railcars are required to prevent the heated mixture from solidifying in cold weather. In the case of raw bitumen, special rail cars with steam coils are required for re-heating bitumen at the destination, and the offloading terminals have to be equipped to heat the rail cars to remove bitumen. Also, as bitumen is heavier than the traditional 70:30 dilbit blend, rail cars can carry less of it and it is more costly to clean the cars afterwards.

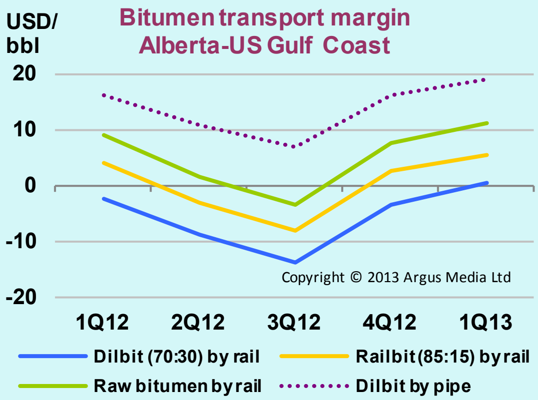
The current price benchmark for Western Canadian Sedimentary Basin crudes, Western Canadian Select (WCS), is heavily discounted compared to similar heavy sour price benchmarks such as Maya in the US Gulf or even ANS in the US West Coast. Canadian industry players tend to see USD 15/bbl between WCS and WTI as a breakeven point to ship bitumen by rail to the US Gulf Coast.

We made a simple calculation of how much profit/loss producers can realise by shipping bitumen to US Gulf Coast by rail to capture Maya prices, as opposed to WCS prices. Our findings show that future eventual pipeline transport would be the most cost-effective option for producers, though. Railing raw bitumen or the 85:15 blend is profitable at present. The economics of shipping bitumen to the West Coast may be more attractive, as the higher price of Alaskan North Slope (ANS), the local price benchmark offsets the longer distances. Indeed, we observe a build-up of offloading/transloading capacity for heavy crudes in both the US West Coast and the US Gulf Coast.

Railing crude in North America (continued)

Uncertainty surrounding the permitting of future major pipeline projects, such as the trans-border Keystone XL pipeline (the final decision is expected in August or later according to TransCanada, the project sponsor), or new takeaway capacity to the Canadian West Coast, may help to further entrench the role of rail in crude transport, especially because bitumen production in Alberta is projected to increase by 400 kb/d by 2015. As it turns out, the optimal transport solution may involve a combination of truck, rail, existing pipelines and barges.





Note (right chart): We assumed that a train car can carry 650 barrels of dilbit vs. 590 barrels of railbit vs. 550 barrels of raw bitumen. As the costs of diluent, we took the price of natural gasoline at Mt Belvieu and we assumed that producers can re-sell or re-use this diluent getting back 85%. Lastly, we assumed that the cost of shipping a train car is USD 13 000 per rail car (*i.e.* USD 20 per barrel of dilbit). We did not consider the cost of special equipment cleaning costs or differences in refining yields. For pipeline transportation, we assumed a cost of USD 10/bbl.

Rail transport and safety

Increasing volumes of crude oil transported by rail raise questions of safety. Our analysis reveals that compared to pipelines, rail incident rates are higher while the opposite holds for spill rates. Readily available statistics on rail transport are inadequate, lacking transport volumes and distances. Data on rail incidents are detailed, but navigating data is challenging as double counting might occur. According to news reports, EIA is addressing existing concerns and is preparing new rail data collection to better cover railroad movements.

We have analysed rail incidents involving crude oil transportation using detailed data on individual train incidents in 2004-12 from the US Department of Transportation. Our calculations imply that between 2004 and 2012, for every 10 mb of crude oil shipped by rail five incidents occurred, while 86 barrels of crude oil were spilled on average. Since the start of Bakken boom, rail incidents increased, but spills have been mostly contained. However, in March 2013, a train derailment in Minnesota that leaked around 700 barrels will result in higher spill levels for 2013.

The data also show that about one third of all US-based incidents over the 2009-12 period involved crude from Williston basin. This represents 18% of spilled crude oil. In 2012, however, 50% of the volume spilled occurred in incidents involving trains carrying Bakken crude. Regarding crude from Permian, in 2012, 17% of all incidents involved trains carrying this crude, but the spills were minimal.

Comparing incident risks and spill volumes between rail and pipe is tricky as the data are not directly comparable. In addition to volumes transported, one has to consider the distance of transport. While barrel-miles data can be easily obtained on pipelines, it is not the case for rail. Assuming 1 000 miles for an average train carload shipment,[5] the incidence and spill rates discussed above also correspond to per-billion-barrel-miles representation.

[5] Most of the Bakken crude is currently being shipped to St. James, Louisiana, approximately 1 700 miles. Therefore, we consider average distance of 1 000 miles being rather conservative.

Railing crude in North America (continued)

Shipping crude oil by rail: Incidence of incidents and volumes released

	2009	2010	2011	2012	2013*	2004-2012 total
Number of crude oil rail cars[1]	10 840	29 605	65 749	233 811	87 306	376 139
Volume of crude oil shipped (kb)[2]	7 588	20 724	46 024	163 668	61 114	263 297
Number of incidents[3]	1	11	31	81	4	135
Volume released (barrels)[3]	0	117	94	90	715	2 269
Incidents per 1mb shipped[4]	**0.1**	**0.5**	**0.7**	**0.5**	**0.1**	**0.5**
Barrels released per 1mb shipped[4]	**0.0**	**5.7**	**2.0**	**0.5**	**11.7**	**8.6**
Trains originating in North Dakota						
Number of incidents[3]	0	6	10	26	1	
Percentage of all spills	0%	2%	8%	50%	0%	
Trains originating in Permian Basin						
Number of incidents[3]	0	0	1	14	0	
Percentage of all spills	0%	0%	0%	1%	0%	

[1]Source: American Association of Railroads.

[2]Assuming 700 barrels per rail car.

[3]Source: Hazmat Intelligence Portal, US Department of Transportation. Retrieved on 30 April 2013.
Incident is reported in case of a release of hazardous material or in a case of damage that, if worse, could have resulted in a release.
For detailed definition, please see http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/reporting_instructions_rev.pdf.

[4]Assuming average transport distance of 1 000 miles, the figures correspond to incident and spill rates per billion barrel-miles.

* Preliminary figures. As of 1Q13. We included March 2013 train derailment in Minnesota that leaked approximately 700 barrels.

To quantify the risk of a pipeline incident, we used US Department of Transportation's data on individual pipeline incidents resulting in crude oil release. Crude oil barrel-miles data come from the same source. Our calculation implies 0.09 incidents and 26 barrels released per 1 billion barrel-miles of crude oil transported by pipeline during a 2004-12 period. Comparing that with figures for rail, we quantify the risk of a train incident to be 6-times higher than that of a pipeline, while pipelines spill 3-times more per 1 billion barrel-miles of crude oil transported, over the 2004-12 period.

Any spill constitutes a railway incident in these calculations, while only spills over 5 gallons constitutes a pipeline spill. Putting both modes of transport on a level playing field by considering spills over 5 gallons only, the rail versus pipeline incident ratio would be only 2:1.

Shipping crude oil by pipeline: Incidence of incidents and volumes released

	2009	2010	2011	2012	2004-2012 total
Billion barrel-miles of crude oil transported by pipeline[1]	1 641	1 804	1 814	1 848	16 357
Number of incidents involving crude oil release[2]	158	156	147	188	1 482
Thousand barrels released[2]	26	53	36	16	424
Incidents per 1 billion barrel-miles	**0.10**	**0.09**	**0.08**	**0.10**	**0.09**
Barrels released per 1 billion barrel-miles	**15.7**	**29.2**	**19.7**	**8.5**	**25.9**

[1]Year 2012 is estimated.

[2]Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety;
Incident is reported in case of a spill of 5 gallons.

Regional trade: where will backed-out crudes find a home?

Despite the commissioning of over 2.5 mb/d of new refining capacity and persistently low production from Iran, crude exports from the **Middle East** are estimated to remain relatively stable, inching up by a minor 30 kb/d over the forecast. As the US takes less Middle Eastern crudes, more of these grades will head to East of Suez markets. Other Asia and China are forecast to import 830 kb/d and 320 kb/d, respectively more of these crudes in 2018. Exports of crude to traditional markets in OECD

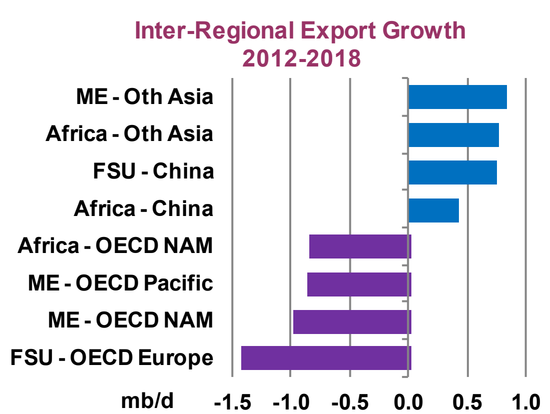
Europe and OECD Pacific are set to decline by a combined 1 mb/d as a further 1.2 mb/d tranche of OECD refining capacity is rationalised. In this case, the blow may be softened somewhat by increasing product exports to those markets.

African exports are foreseen to decline by 110 kb/d to 6.9 mb/d in 2018 following a 380 kb/d contraction forecast in Algerian supply and pessimistic projections of growth in Angola and Nigeria. Additionally, the region is expected to add over 400 kb/d of refining capacity over the forecast which will mainly be used to supply domestic, rather than export markets. With shipments to North America plummeting by 840 kb/d, consignments to OECD Europe will contract by a steep 630 kb/d as the refinery sector there is rationalised. In contrast, Other Asia is projected to step up its imports of African crudes by 760 kb/d. India in particular is projected to run these crudes in its new refining complexes due to come online over the forecast.

Latin American exports are foreseen to remain relatively constant at 2.1 mb/d despite the commissioning of a net 200 kb/d of regional refining capacity. The 320 kb/d drop in OECD North America exports will see crudes make their way East, notably to Other Asia. Exports there are set to rise by 350 kb/d facilitated by the expansion of the Panama Canal, currently expected to be completed in 2014, permitting Suezmax sized tankers to navigate from the Atlantic to Pacific basins. Although China is seen continuing to take 500 kb/d of heavy Venezuelan crude across the forecast, it is worth noting that Chinese companies, particularly PetroChina, have been investing heavily in infrastructure in the region to facilitate such trades, thus suggesting that importing these crudes may be a long-term strategy.

Due to the addition of over 700 kb/d of regional refining capacity, exports from the **Former Soviet Union** are seen slipping by 240 kb/d to 6.1 mb/d over the forecast. Nonetheless, the region will continue to diversify its exports away from its traditional markets in OECD Europe where imports are seen to fall by 1.4 mb/d to 2.9 mb/d in 2018. Crude will continue to be preferentially exported to lucrative Asian markets, notably China, where FSU exports are projected to more than double from 660 kb/d in 2012 to 1.4 mb/d in 2018. This shift is seen against the backdrop of recent 2012 expansion of the East Siberian Pacific Ocean (ESPO) pipeline and the March 2013 framework agreement for Rosneft to supply CNPC with 1 mb/d of crude in exchange for a loan to finance its purchase of TNK-BP (see: A New Supermajor: How the TNK-BP Acquisition Could Affect Trade Flows in April 2013 OMR). Additionally, ESPO blend crude has also found a home in many ASEAN refineries. Accordingly, FSU exports to Other Asia are projected to almost double to over 700 kb/d by 2018.

Crude imports into the **non-OECD** are projected to surpass those of the OECD in 2018. This is driven by two factors. One is the result of rising oil demand and refinery expansions in China and in India, Malaysia and Thailand in Other Asia. The other concerns the decrease in North American imports and further refinery rationalisation in OECD Pacific and OECD Europe. All told, non-OECD imports are projected to rise from 12.6 mb/d in 2012 to 16.5 mb/d in 2018 while those in the OECD fall from 20.7 mb/d in 2012 to 15.9 mb/d in 2018.



Shifting trade patterns will have wide-ranging consequences for the **tanker market**. As stated previously, although global trade in crude oil is set to decrease by 0.9 mb/d over 2012-18, product trade is set to increase as more products are set to be refined close to the wellhead. The main development since the 2012 *MTOMR* concerns the surge in product trade from the US as it exports products, notably gasoline and naphtha refined from light crudes, around the Atlantic Basin to Latin America and Europe.

How US condensate is changing the world

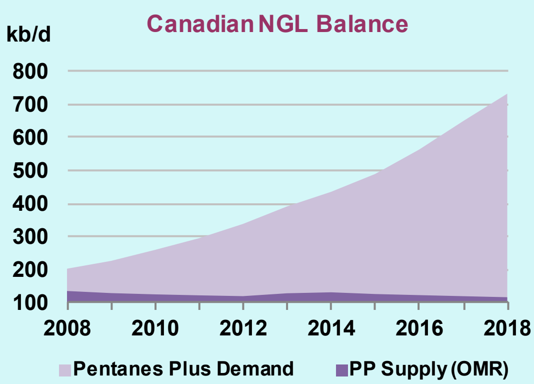
The unique properties and quality of US LTO make surging LTO production both an opportunity and a challenge for US refiners, many of which had been investing for years in units designed to process an ever heavier crude oil slate, and for the oil market as a whole. The emergence of the Eagle Ford as a major tight oil play, in particular, is forcing the refining industry to adjust in order to take advantage of its mix of exceptionally light crude oil and lease condensate. Though estimates cover a wide range, around 0.3-0.5 mb/d of lease condensate supply is expected to be added by 2018 that will come mainly from the Eagle Ford. Assuming that current restrictions on crude and unprocessed lease condensate exports stay in place, the industry is likely to respond to this new supply by reconfiguring its feedstock mix and by expanding condensate splitting capacity.

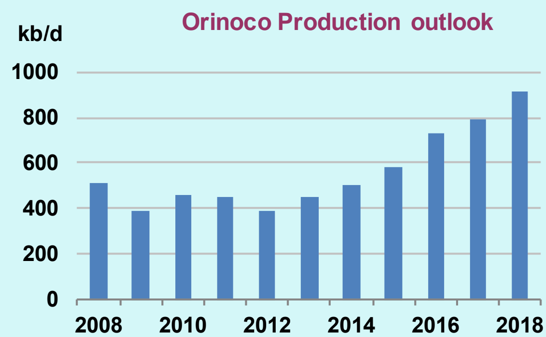
Unlike processed condensate (pentanes plus), exports of which are allowed under US law, unprocessed field condensate or lease condensate is subject to export restrictions under existing US trade regulations. Lease condensate is extracted from oil wells and is liquid at atmospheric pressure, whereas marketed pentanes plus is mostly produced from fractioning plants - wet gas obtained from processing dry gas. The US market's ability to absorb rising volumes of Eagle Ford condensate or process them for export as products will help determine the play's economic viability in the medium term.

Pentanes plus, not field condensate to meet rising Canadian and Venezuelan import demand

While Canadian oil producers have been large users of US condensate to blend and process heavy Canadian crude, they are not expected to provide an outlet for Eagle Ford condensate as they can only import pentanes plus. For Canadian diluted bitumen, Eagle Ford will be used for marginal volumes from those producers which have been granted export licenses. Currently, Canada meets roughly one third of its diluent demand with imports of pentanes plus from the US. In general, Canadian oil producers prefer to use pentane plus, as opposed to field condensate, as the lower API gravity of pentane plus makes it a more efficient diluent.

The same applies to Venezuela, where diluent demand could increase from its 2012 level by as much as 50 kb/d through 2018 if planned new projects in the Orinoco come to completion.



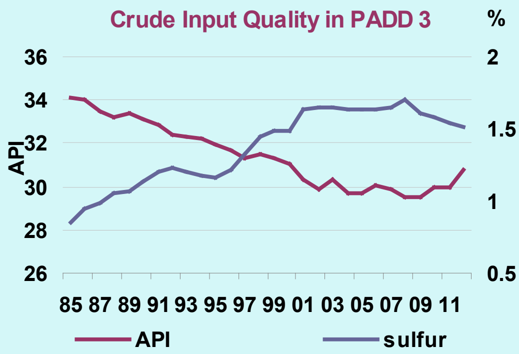


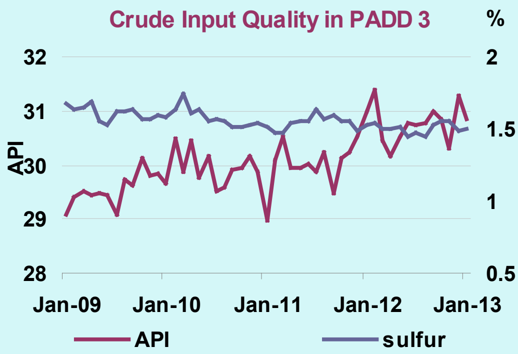
How US condensate is changing the world (continued)

Light crude and condensate do not match desired crude slate of US Gulf Coast refiners

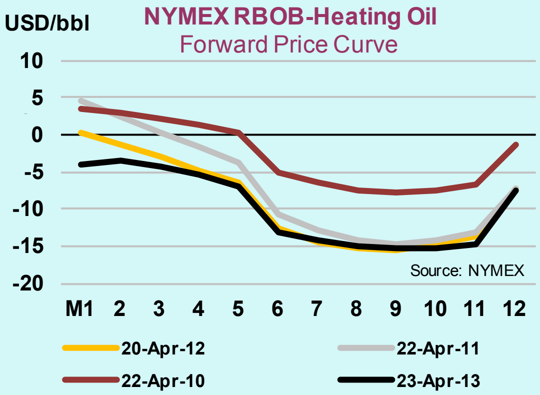
In recent years, most investments at US refineries, particularly on the Gulf Coast, have been made in order to increase yields of high value-added products, such as gasoline and distillates, from heavier crude. As heavy crude had been traditionally selling at a discount to light crude, refineries with upgrading capacity, such as cokers, enjoyed a competitive advantage. But surging LTO production is causing the light/heavy spread to narrow. Given the expected continuing growth in LTO production, there is an emerging mismatch between the desired crude slate for refiners and the crude that is being produced in the US.

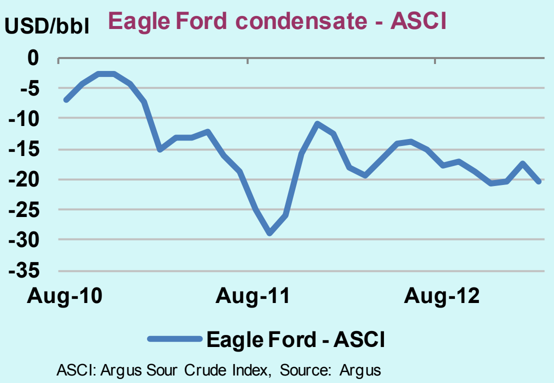
For refiners that have invested in heavy upgrading capacity, using a lighter crude slate (lease condensate or heavier crude blended with condensate) would leave upgrading units, designed to handle heavier crude, underutilised, which is costly. As a result, only a small amount of lease condensate or lighter crude will be processed by refineries with heavy upgrading capacity. Even for less complex refineries, running a lighter crude slate will increase yields of lighter ends, like those used for gasoline blending, at the expense of distillate. This can adversely affect refining economics as gasoline typically trades at a discount to distillate.





Nonetheless, US refineries since 2009 have started to switch towards a lighter and sweeter crude slate. This is already resulting in excess production of light ends, as rising yields and production compound the impact of a structural downtrend in US demand for both gasoline and naphtha.





How US condensate is changing the world (continued)

Surging condensate output will incentivise condensate splitting capacity expansions

Given the mismatch between the desired crude slate of Gulf Coast refiners and the quality of growing tight oil and condensate, investing in condensate splitters is a potentially attractive investment. The steep price discount of condensate to heavier US crude prices – about USD 20/bbl at the time of writing – provides a strong economic incentive to expand splitting capacity. Building new splitters to accommodate cheap light crude will be less costly and quicker than the investments made in heavy upgrading capacity. With the rising production of US production of non-conventional gas, which is driving down naphtha prices in the US, the best bet is that this naphtha will be exported.

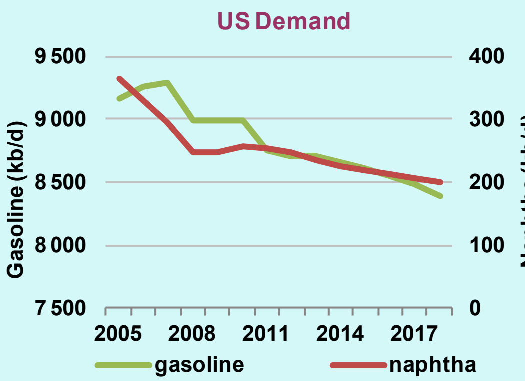
Kinder Morgan plans to double its splitter capacity to 100 kb/d. The first phase of the expansion (25 kb/d) is expected to be completed in 1Q14. Although Valero was granted permission by US regulators to send a limited amount of crude to its Quebec refinery, the company wants to build a new splitter which would allow it to export products (mainly naphtha) out of the US Gulf Coast. Marathon expects that the additional volumes of condensate which will be produced in Ohio's Utica and Pennsylvania's Marcellus tight oil play will be used by its planned new splitter. As the refinery is far away from the US Gulf Coast, products from this splitter would be commercialised in the US. Overall these three projects could increase splitter capacity by 200 kb/d to 300 kb/d. Splitter additions could be even larger in the next five years if the condensate discount versus US heavier crude widens further.

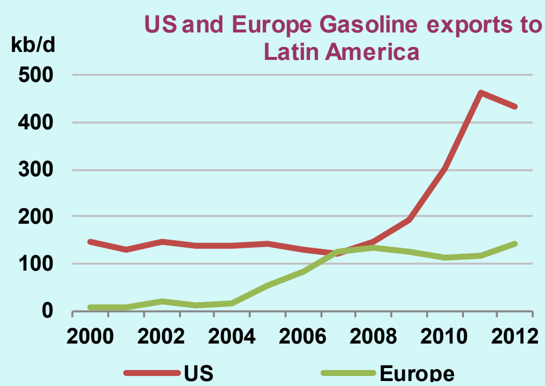
Additional Splitter List

Company	Additional Capacity (kb/d)	Comments
Kinder Morgan	50	Galena Park, Texas (Houston Ship Channel)
Valero	75-125	Three Rivers, Texas & Corpus Christi, Texas
Marathon	75-125	Canton, Ohio & Catlettsburg, Kentucky
Total	**200-300**	

Rising US gasoline exports in search of new markets

With the increase in light ends production, it could add length to the Gulf Coast gasoline market, making more available for export. The major export outlets for gasoline will be Latin America and some other regions such as Africa, Middle East and Asia depending on the relative competitiveness of US gasoline versus European gasoline exports. Latin America should be the region showing fastest growth in gasoline imports due to its growing population, gasoline subsidies and lack of investments in refining.



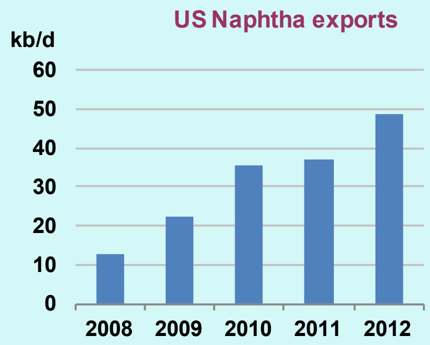


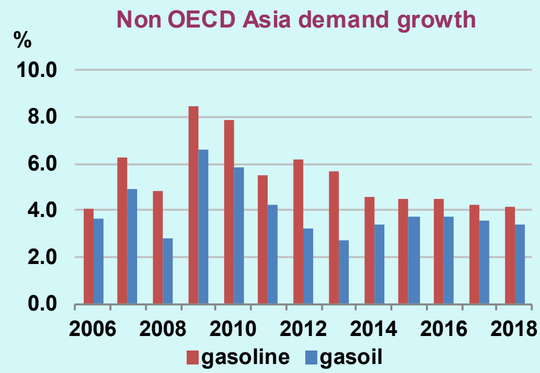
How US condensate is changing the world (continued)

Around 2004, Europe began to quickly ramp up gasoline exports to Latin America, and by 2008, exported a share equivalent to that of the US. However, since 2008 the gap widened again with the US exceeding its market share (versus Europe) by more than 300 kb/d over last two years.

Rising US naphtha exports will target Asia

US naphtha exports have also been trending up in recent years. From a low level of 13 kb/d in 2008, US naphtha exports reached about 50 kb/d in 2012. In October 2012, exports reached a record high of 59 kb/d. Depending on economics, US naphtha could start to compete with European naphtha in Asia as the recent trend suggests.

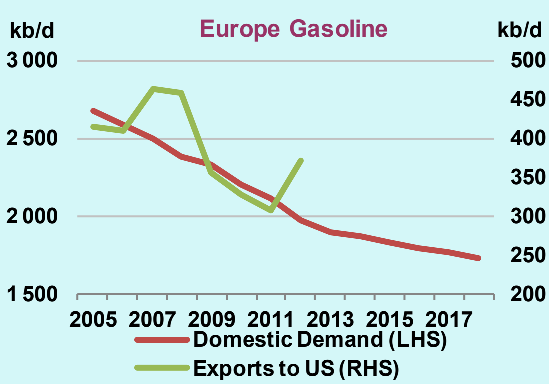


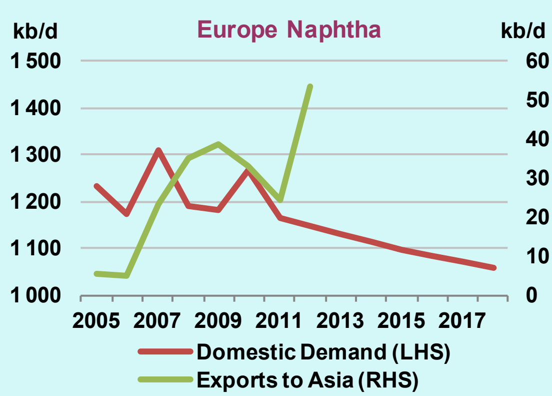


Given the expected continuing strong growth in Asian petrochemical and refining sectors, it is likely that the market will have the capacity to absorb incremental naphtha supplies. Based on forecast strong Asian economic growth (non-OECD: 6.0% and China: 8.5%), feedstock demand will grow for manufacturing gasoline, ethylene and aromatics, which will pull naphtha imports to the continent. The two major driving factors behind this import pull will be: 1) gasoline demand continuing to outpace diesel demand and 2) olefins crackers capacity increasing at a higher rate than splitter capacity. In our outlook, non OECD Asian naphtha demand is projected to grow at 3.9 %.

European refining margins at risk

Unless Europe can export its naphtha surplus, a reduction in European petrochemical capacity could have a further devastating impact on European refining margins. Following a major drop in European gasoline demand and gasoline exports to the US, European margins – notably hydroskimming margins – could shrink significantly. Hydroskimming refineries totaling 620 kb/d of capacity could be at risk if more petrochemical units are closed.





How US condensate is changing the world (continued)

Thus, the next closure could be at one of SABIC's, the world biggest petrochemical group, the plant following the latest announcement by SABIC that some operations will close in Europe following 1Q13 negative earnings.

Conclusion

Unless US trade regulations are amended, rising production of US lease condensate will be consumed domestically. US refining will respond to lower condensate prices by investing in splitters and changing their existing refineries configuration. As US gasoline demand continues its structural decline and the US petrochemical industry further switches away from naphtha in favour of cheaper feedstock such as ethane, more US gasoline and naphtha will be available for export, notably to Latin America and Asia. This could put further pressure on European margins as European gasoline domestic demand is falling, gasoline exports to the US are drying up and European naphtha demand is shrinking due to shut down of uneconomical olefins crackers. The survival of the European refineries will depend on the relative strength of Asian light-ends demand and the degree of competitiveness of US light-ends products produced from cheap light crude.

Table 1

WORLD OIL SUPPLY AND DEMAND

(million barrels per day)

	1Q12	2Q12	3Q12	4Q12	2012	1Q13	2Q13	3Q13	4Q13	2013	2014	2015	2016	2017	2018
OECD DEMAND															
Americas[1]	23.5	23.8	23.9	23.8	23.7	23.7	23.6	23.8	23.8	23.7	23.7	23.6	23.5	23.4	23.3
Europe[2]	13.7	13.8	13.8	13.6	13.7	13.1	13.1	13.6	13.6	13.4	13.3	13.2	13.1	13.0	12.9
Asia Oceania[3]	9.1	8.0	8.2	8.7	8.5	9.0	7.9	8.1	8.5	8.3	8.3	8.3	8.3	8.3	8.2
Total OECD	46.2	45.5	45.9	46.1	45.9	45.8	44.6	45.5	45.9	45.4	45.2	45.1	44.9	44.7	44.4
NON-OECD DEMAND															
FSU	4.4	4.4	4.6	4.6	4.5	4.4	4.5	4.8	4.8	4.6	4.8	4.9	5.0	5.1	5.3
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
China	9.3	9.4	9.6	10.1	9.6	9.8	9.8	9.9	10.4	10.0	10.4	10.8	11.2	11.6	12.0
Other Asia	11.3	11.4	11.1	11.5	11.3	11.6	11.7	11.4	11.8	11.6	11.9	12.2	12.5	12.8	13.2
Latin America	6.3	6.5	6.6	6.7	6.5	6.5	6.6	6.8	6.8	6.7	6.9	7.0	7.2	7.3	7.4
Middle East	7.3	7.8	8.1	7.5	7.7	7.5	7.9	8.3	7.7	7.8	8.1	8.4	8.7	8.9	9.2
Africa	3.5	3.5	3.5	3.6	3.5	3.7	3.7	3.7	3.7	3.7	3.9	4.0	4.2	4.3	4.5
Total Non-OECD	42.7	43.7	44.3	44.7	43.9	44.1	44.9	45.6	45.9	45.1	46.6	48.1	49.5	50.9	52.3
Total Demand[4]	89.0	89.2	90.2	90.8	89.8	89.9	89.5	91.1	91.8	90.6	91.8	93.1	94.4	95.6	96.7
OECD SUPPLY															
Americas[1]	15.6	15.5	15.7	16.6	15.8	16.7	16.5	16.9	17.4	16.9	17.5	18.1	18.6	19.2	19.8
Europe[2]	3.8	3.6	3.2	3.3	3.5	3.4	3.3	3.1	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Asia Oceania[3]	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.6
Total OECD	19.9	19.6	19.4	20.4	19.8	20.6	20.3	20.6	21.3	20.7	21.4	22.0	22.6	23.2	23.7
NON-OECD SUPPLY															
FSU	13.7	13.6	13.6	13.8	13.7	13.8	13.6	13.4	13.6	13.6	13.6	13.8	13.8	13.6	13.7
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	4.1	4.2	4.3	4.2	4.2	4.3	4.3	4.3	4.3	4.3	4.3	4.4	4.5	4.4
Other Asia[5]	3.6	3.5	3.6	3.6	3.6	3.6	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.5	3.4
Latin America[5,7]	4.3	4.1	4.1	4.2	4.2	4.2	4.1	4.3	4.4	4.2	4.6	4.9	5.0	5.2	5.4
Middle East	1.4	1.5	1.5	1.5	1.5	1.4	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.3	1.3
Africa[5]	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.5	2.4	2.5	2.5	2.5	2.6	2.7
Total Non-OECD	29.8	29.2	29.3	29.8	29.5	29.7	29.5	29.4	29.9	29.6	30.1	30.5	30.6	30.8	30.9
Processing Gains[6]	2.1	2.1	2.2	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.4
Global Biofuels[7]	1.5	1.9	2.1	1.9	1.9	1.5	1.9	2.3	2.0	1.9	2.1	2.2	2.3	2.3	2.4
Total Non-OPEC[5]	53.3	52.8	53.0	54.2	53.4	53.9	53.9	54.5	55.3	54.4	55.8	57.0	57.8	58.6	59.3
OPEC															
Crude[8]	31.3	31.7	31.4	30.9	31.3	30.5									
OPEC NGLs	6.1	6.2	6.4	6.4	6.3	6.4	6.5	6.6	6.7	6.6	6.7	6.9	7.0	7.0	7.0
Total OPEC[5]	37.5	37.9	37.9	37.3	37.6	36.9									
Total Supply[9]	90.8	90.8	90.9	91.5	91.0	90.8									
Memo items:															
Call on OPEC crude + Stock ch.[10]	29.5	30.2	30.8	30.1	30.1	29.6	29.1	30.0	29.8	29.6	29.3	29.2	29.6	30.0	30.4

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)

	1Q12	2Q12	3Q12	4Q12	2012	1Q13	2Q13	3Q13	4Q13	2013	2014	2015	2016	2017	2018
OECD DEMAND															
Americas	0.0	0.0	-0.3	-0.3	-0.1	0.1	0.0	-0.3	-0.3	-0.1	-0.2	-0.2	-0.3	-0.3	
Europe	-0.1	-0.1	-0.6	-0.4	-0.3	-0.4	-0.5	-0.6	-0.3	-0.4	-0.5	-0.5	-0.5	-0.5	
Asia Oceania	0.0	0.0	0.1	0.2	0.1	-0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	
Total OECD	-0.1	-0.1	-0.7	-0.4	-0.3	-0.4	-0.4	-0.8	-0.4	-0.5	-0.5	-0.6	-0.6	-0.7	
NON-OECD DEMAND															
FSU	0.0	-0.1	-0.1	-0.1	-0.1	-0.2	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.1	-0.1	
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	
China	-0.3	0.1	0.3	0.3	0.1	0.0	0.2	0.3	0.3	0.2	0.3	0.3	0.3	0.3	
Other Asia	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	
Latin America	0.0	0.0	0.0	0.2	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	
Middle East	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	
Africa	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.4	
Total Non-OECD	-0.2	0.3	0.5	0.6	0.3	0.3	0.4	0.7	0.6	0.5	0.5	0.5	0.6	0.6	
Total Demand	-0.3	0.3	-0.1	0.2	0.0	-0.1	0.0	-0.1	0.2	0.0	0.0	0.0	-0.1	-0.1	
OECD SUPPLY															
Americas	0.0	-0.1	-0.1	0.5	0.1	0.6	0.3	0.6	0.7	0.5	0.7	0.6	0.5	0.5	
Europe	0.0	0.0	0.0	-0.1	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	
Asia Oceania	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	
Total OECD	0.0	-0.1	-0.1	0.4	0.1	0.5	0.3	0.6	0.7	0.5	0.7	0.6	0.7	0.8	
NON-OECD SUPPLY															
FSU	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.1	0.0	-0.1	0.1	0.1	0.0	
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	
China	0.0	0.0	0.1	0.2	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	
Other Asia	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	
Latin America	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.2	-0.1	-0.1	-0.1	0.1	0.2	0.1	0.2	
Middle East	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	0.1	
Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	-0.1	-0.1	-0.2	
Total Non-OECD	0.0	-0.1	0.2	0.3	0.1	0.2	-0.1	-0.1	0.2	0.0	0.3	0.4	0.2	0.3	
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	
Global Biofuels	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	
Total Non-OPEC	0.0	-0.1	0.1	0.6	0.1	0.5	0.0	0.5	0.9	0.5	0.9	1.0	0.9	1.0	
OPEC															
Crude	0.0	0.0													
OPEC NGLs	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	
Total OPEC	0.0	0.0													
Total Supply	-0.1	-0.1													
Memo items:															
Call on OPEC crude + Stock ch.	-0.3	0.3	-0.3	-0.4	-0.2	-0.6	-0.1	-0.6	-0.6	-0.5	-0.9	-1.0	-1.0	-1.1	

Table 2

SUMMARY OF GLOBAL OIL DEMAND

	1Q12	2Q12	3Q12	4Q12	2012	1Q13	2Q13	3Q13	4Q13	2013	2014	2015	2016	2017	2018
Demand (mb/d)															
Americas[1]	23.48	23.78	23.89	23.80	23.74	23.72	23.61	23.84	23.80	23.74	23.70	23.62	23.51	23.40	23.27
Europe[2]	13.66	13.75	13.77	13.63	13.70	13.13	13.11	13.58	13.63	13.36	13.27	13.20	13.12	13.05	12.95
Asia Oceania[3]	9.08	7.97	8.23	8.68	8.49	8.96	7.87	8.05	8.48	8.34	8.27	8.26	8.26	8.25	8.21
Total OECD	46.23	45.49	45.89	46.11	45.93	45.80	44.60	45.48	45.91	45.45	45.24	45.08	44.90	44.70	44.43
Asia	20.57	20.83	20.74	21.62	20.94	21.40	21.48	21.29	22.14	21.58	22.27	23.01	23.73	24.43	25.12
Middle East	7.26	7.79	8.14	7.47	7.66	7.47	7.89	8.31	7.69	7.84	8.10	8.37	8.66	8.95	9.23
Latin America	6.26	6.46	6.64	6.70	6.51	6.49	6.60	6.83	6.78	6.68	6.86	7.02	7.16	7.29	7.41
FSU	4.44	4.42	4.59	4.60	4.51	4.44	4.54	4.77	4.81	4.64	4.77	4.90	5.02	5.15	5.27
Africa	3.51	3.49	3.50	3.58	3.52	3.65	3.68	3.67	3.75	3.69	3.85	4.01	4.17	4.31	4.46
Europe	0.68	0.73	0.72	0.72	0.72	0.68	0.73	0.74	0.74	0.72	0.73	0.74	0.76	0.77	0.78
Total Non-OECD	42.73	43.72	44.33	44.68	43.85	44.13	44.93	45.60	45.92	45.15	46.58	48.06	49.50	50.90	52.27
World	88.96	89.21	90.22	90.79	89.78	89.93	89.52	91.07	91.83	90.60	91.82	93.14	94.40	95.60	96.70
of which:															
US50	*18.48*	*18.71*	*18.72*	*18.51*	*18.61*	*18.56*	*18.52*	*18.66*	*18.56*	*18.58*	*18.54*	*18.47*	*18.39*	*18.30*	*18.18*
Euro5	*8.26*	*8.20*	*8.20*	*8.12*	*8.19*	*7.90*	*7.77*	*8.02*	*8.09*	*7.94*	*7.85*	*7.78*	*7.71*	*7.63*	*7.54*
China	*9.30*	*9.40*	*9.60*	*10.09*	*9.60*	*9.80*	*9.81*	*9.91*	*10.37*	*9.98*	*10.36*	*10.79*	*11.19*	*11.58*	*11.96*
Japan	*5.28*	*4.30*	*4.48*	*4.85*	*4.73*	*5.15*	*4.18*	*4.30*	*4.62*	*4.56*	*4.48*	*4.45*	*4.43*	*4.41*	*4.35*
India	*3.67*	*3.74*	*3.49*	*3.71*	*3.65*	*3.71*	*3.81*	*3.57*	*3.86*	*3.74*	*3.86*	*3.98*	*4.11*	*4.24*	*4.36*
Russia	*3.20*	*3.25*	*3.42*	*3.39*	*3.32*	*3.21*	*3.35*	*3.60*	*3.57*	*3.44*	*3.55*	*3.67*	*3.78*	*3.88*	*3.99*
Brazil	*2.89*	*2.95*	*3.05*	*3.14*	*3.00*	*3.03*	*3.04*	*3.15*	*3.18*	*3.10*	*3.18*	*3.27*	*3.33*	*3.39*	*3.44*
Saudi Arabia	*2.66*	*3.09*	*3.41*	*2.88*	*3.01*	*2.81*	*3.20*	*3.51*	*3.02*	*3.14*	*3.26*	*3.38*	*3.51*	*3.65*	*3.78*
Korea	*2.31*	*2.19*	*2.23*	*2.34*	*2.27*	*2.32*	*2.20*	*2.23*	*2.32*	*2.27*	*2.27*	*2.27*	*2.27*	*2.27*	*2.26*
Canada	*2.20*	*2.25*	*2.38*	*2.34*	*2.29*	*2.27*	*2.25*	*2.35*	*2.33*	*2.30*	*2.29*	*2.28*	*2.26*	*2.24*	*2.22*
Mexico	*2.14*	*2.18*	*2.16*	*2.28*	*2.19*	*2.22*	*2.20*	*2.17*	*2.25*	*2.21*	*2.20*	*2.19*	*2.17*	*2.16*	*2.15*
Iran	*1.83*	*1.86*	*1.71*	*1.71*	*1.78*	*1.79*	*1.77*	*1.71*	*1.72*	*1.75*	*1.76*	*1.78*	*1.81*	*1.84*	*1.86*
Total	*62.22*	*62.14*	*62.85*	*63.36*	*62.64*	*62.77*	*62.11*	*63.19*	*63.90*	*63.00*	*63.61*	*64.31*	*64.96*	*65.59*	*66.10*
% of World	*69.94*	*69.65*	*69.66*	*69.79*	*69.77*	*69.79*	*69.38*	*69.38*	*69.59*	*69.53*	*69.27*	*69.04*	*68.82*	*68.60*	*68.35*
Annual Change (% per annum)															
Americas[1]	-2.8	-0.1	-1.2	-0.7	-1.2	1.0	-0.7	-0.2	0.0	0.0	-0.2	-0.3	-0.4	-0.5	-0.6
Europe[2]	-4.1	-3.0	-6.6	-3.6	-4.3	-3.9	-4.6	-1.3	0.0	-2.5	-0.7	-0.5	-0.6	-0.6	-0.8
Asia Oceania[3]	5.9	7.5	2.9	1.0	4.2	-1.4	-1.2	-2.2	-2.3	-1.8	-0.8	-0.1	0.0	-0.1	-0.5
Total OECD	-1.6	0.3	-2.2	-1.3	-1.2	-0.9	-2.0	-0.9	-0.4	-1.1	-0.5	-0.4	-0.4	-0.4	-0.6
Asia	2.1	2.2	3.6	5.1	3.3	4.0	3.1	2.6	2.4	3.0	3.2	3.3	3.1	3.0	2.8
Middle East	3.6	4.9	3.6	1.2	3.3	2.9	1.4	2.1	3.0	2.3	3.2	3.4	3.5	3.3	3.1
Latin America	3.4	3.2	2.6	4.9	3.5	3.6	2.3	2.9	1.3	2.5	2.7	2.4	2.0	1.8	1.6
FSU	6.3	2.6	1.4	1.5	2.9	0.0	2.7	4.0	4.7	2.9	2.8	2.7	2.5	2.4	2.3
Africa	2.1	2.3	6.3	5.7	4.1	4.0	5.3	4.7	4.8	4.7	4.5	4.2	3.8	3.5	3.4
Europe	2.9	7.1	2.5	0.6	3.2	-0.4	-1.2	2.9	1.6	0.8	1.5	1.6	1.6	1.5	1.5
Total Non-OECD	3.0	2.9	3.4	4.0	3.3	3.3	2.8	2.9	2.8	3.0	3.2	3.2	3.0	2.8	2.7
World	0.5	1.6	0.5	1.3	0.9	1.1	0.3	1.0	1.1	0.9	1.4	1.4	1.4	1.3	1.1
Annual Change (mb/d)															
Americas[1]	-0.69	-0.01	-0.29	-0.17	-0.29	0.23	-0.16	-0.05	0.00	0.00	-0.04	-0.08	-0.11	-0.11	-0.14
Europe[2]	-0.58	-0.42	-0.97	-0.50	-0.62	-0.53	-0.64	-0.18	0.00	-0.34	-0.10	-0.07	-0.07	-0.07	-0.10
Asia Oceania[3]	0.50	0.56	0.23	0.09	0.35	-0.13	-0.10	-0.18	-0.20	-0.15	-0.07	-0.01	0.00	-0.01	-0.04
Total OECD	-0.77	0.12	-1.03	-0.59	-0.57	-0.43	-0.90	-0.41	-0.20	-0.48	-0.21	-0.16	-0.18	-0.19	-0.27
Asia	0.43	0.44	0.73	1.04	0.66	0.83	0.66	0.55	0.52	0.64	0.70	0.73	0.72	0.70	0.69
Middle East	0.26	0.36	0.28	0.09	0.25	0.21	0.11	0.17	0.23	0.18	0.25	0.28	0.29	0.29	0.28
Latin America	0.20	0.20	0.17	0.31	0.22	0.23	0.15	0.19	0.09	0.16	0.18	0.17	0.14	0.13	0.12
FSU	0.26	0.11	0.06	0.07	0.13	0.00	0.12	0.18	0.22	0.13	0.13	0.13	0.12	0.12	0.12
Africa	0.07	0.08	0.21	0.19	0.14	0.14	0.19	0.16	0.17	0.17	0.17	0.16	0.15	0.15	0.15
Europe	0.02	0.05	0.02	0.00	0.02	0.00	-0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total Non-OECD	1.24	1.25	1.46	1.71	1.39	1.40	1.21	1.27	1.23	1.30	1.43	1.48	1.44	1.40	1.37
World	0.47	1.37	0.43	1.12	0.83	0.97	0.31	0.86	1.04	0.82	1.23	1.32	1.26	1.21	1.09
Revisions to Oil Demand from Last Medium Term Report (mb/d)															
Americas[1]	0.00	0.01	-0.26	-0.25	-0.13	0.15	-0.02	-0.35	-0.32	-0.14	-0.15	-0.19	-0.25	-0.29	
Europe[2]	-0.12	-0.07	-0.58	-0.37	-0.29	-0.42	-0.46	-0.60	-0.26	-0.44	-0.46	-0.47	-0.48	-0.48	
Asia Oceania[3]	0.00	-0.02	0.15	0.24	0.09	-0.11	0.12	0.16	0.21	0.10	0.09	0.09	0.09	0.09	
Total OECD	-0.11	-0.09	-0.69	-0.39	-0.32	-0.39	-0.37	-0.78	-0.37	-0.48	-0.52	-0.57	-0.63	-0.69	
Asia	-0.31	0.19	0.38	0.40	0.17	0.10	0.24	0.46	0.37	0.30	0.33	0.31	0.31	0.31	
Middle East	0.08	0.09	0.10	-0.03	0.06	0.09	0.05	0.04	-0.01	0.04	0.03	0.00	-0.03	-0.06	
Latin America	0.01	0.02	0.04	0.20	0.07	0.12	0.06	0.08	0.16	0.10	0.13	0.14	0.14	0.12	
FSU	-0.01	-0.05	-0.12	-0.12	-0.07	-0.18	-0.13	-0.09	-0.12	-0.13	-0.17	-0.16	-0.14	-0.10	
Africa	0.07	0.09	0.13	0.14	0.11	0.13	0.16	0.18	0.20	0.17	0.21	0.26	0.30	0.35	
Europe	0.00	0.00	0.01	0.01	0.00	-0.01	-0.01	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	
Total Non-OECD	-0.17	0.34	0.54	0.60	0.33	0.26	0.36	0.67	0.61	0.47	0.52	0.55	0.58	0.62	
World	-0.28	0.26	-0.15	0.21	0.01	-0.13	-0.01	-0.11	0.24	0.00	0.00	-0.03	-0.05	-0.07	
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)															
World	0.00	0.13	-0.39	0.32	-0.01	0.15	-0.26	0.03	0.03	0.01	0.00	-0.03	-0.03	-0.02	

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)

	1Q12	2Q12	3Q12	4Q12	2012	1Q13	2Q13	3Q13	4Q13	2013	2014	2015	2016	2017	2018
OPEC															
Crude Oil															
Saudi Arabia	9.60	9.71	9.51	9.23	9.51	9.01									
Iran	3.37	3.14	2.81	2.71	3.00	2.68									
Iraq	2.69	2.92	3.07	3.12	2.95	3.01									
UAE	2.61	2.65	2.69	2.67	2.65	2.67									
Kuwait	2.45	2.47	2.49	2.54	2.49	2.58									
Neutral Zone	0.57	0.56	0.53	0.52	0.54	0.52									
Qatar	0.75	0.74	0.75	0.72	0.74	0.74									
Angola	1.77	1.79	1.78	1.79	1.78	1.76									
Nigeria	2.06	2.17	2.17	1.99	2.10	1.98									
Libya	1.30	1.40	1.43	1.42	1.39	1.38									
Algeria	1.16	1.16	1.18	1.16	1.17	1.15									
Ecuador	0.50	0.50	0.50	0.50	0.50	0.50									
Venezuela	2.52	2.50	2.52	2.48	2.50	2.50									
Total Crude Oil	31.33	31.72	31.43	30.85	31.33	30.47									
Total NGLs[1]	6.15	6.19	6.44	6.45	6.31	6.43	6.50	6.61	6.68	6.56	6.75	6.90	7.00	6.97	7.00
Total OPEC[2]	37.48	37.91	37.87	37.30	37.64	36.90									
NON-OPEC[3]															
OECD															
Americas[7]	15.56	15.50	15.66	16.61	15.83	16.72	16.53	16.91	17.38	16.89	17.53	18.07	18.64	19.21	19.76
United States[6]	8.84	8.91	9.07	9.74	9.14	9.81	9.91	10.02	10.24	10.00	10.58	11.02	11.47	11.76	11.92
Mexico	2.92	2.93	2.93	2.90	2.92	2.94	2.91	2.90	2.89	2.91	2.89	2.89	2.87	2.86	2.83
Canada	3.79	3.64	3.65	3.95	3.76	3.95	3.70	3.98	4.24	3.97	4.05	4.15	4.28	4.58	5.00
Chile	0.02	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]	3.80	3.61	3.17	3.34	3.48	3.39	3.30	3.10	3.32	3.28	3.28	3.30	3.33	3.33	3.29
UK	1.10	1.02	0.83	0.89	0.96	0.95	0.89	0.74	0.86	0.86	0.91	0.93	0.99	1.01	1.00
Norway	2.09	1.98	1.75	1.84	1.91	1.83	1.82	1.78	1.88	1.83	1.82	1.84	1.83	1.79	1.75
Others	0.61	0.61	0.59	0.61	0.60	0.61	0.59	0.58	0.58	0.59	0.55	0.52	0.51	0.54	0.53
Asia Oceania[9]	0.52	0.54	0.56	0.50	0.53	0.45	0.52	0.56	0.57	0.53	0.60	0.63	0.63	0.62	0.62
Australia	0.43	0.46	0.48	0.43	0.45	0.37	0.44	0.48	0.49	0.45	0.53	0.56	0.57	0.56	0.55
Others	0.09	0.09	0.08	0.08	0.08	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.06	0.06	0.07
Total OECD	19.88	19.65	19.39	20.45	19.84	20.56	20.35	20.58	21.27	20.69	21.40	21.99	22.61	23.17	23.67
NON-OECD															
Former USSR	13.72	13.60	13.58	13.77	13.67	13.84	13.60	13.43	13.63	13.63	13.58	13.76	13.80	13.65	13.65
Russia	10.72	10.68	10.70	10.83	10.73	10.84	10.73	10.56	10.65	10.69	10.68	10.69	10.72	10.73	10.76
Others	3.01	2.92	2.88	2.94	2.94	3.01	2.87	2.87	2.98	2.93	2.90	3.08	3.09	2.92	2.90
Asia	7.81	7.63	7.74	7.88	7.76	7.81	7.82	7.78	7.77	7.79	7.87	7.94	7.95	8.00	7.83
China	4.18	4.09	4.17	4.27	4.18	4.21	4.27	4.26	4.26	4.25	4.32	4.31	4.35	4.48	4.41
Malaysia	0.70	0.64	0.65	0.69	0.67	0.70	0.69	0.69	0.70	0.70	0.72	0.74	0.74	0.72	0.69
India	0.90	0.91	0.91	0.91	0.91	0.93	0.92	0.91	0.91	0.92	0.90	0.90	0.88	0.84	0.80
Indonesia	0.91	0.90	0.88	0.87	0.89	0.85	0.84	0.81	0.80	0.82	0.77	0.79	0.79	0.79	0.75
Others	1.11	1.09	1.13	1.14	1.12	1.12	1.11	1.10	1.11	1.11	1.16	1.19	1.19	1.17	1.18
Europe	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.13	0.13	0.12	0.11	0.10	0.09
Latin America	4.28	4.15	4.11	4.20	4.18	4.18	4.13	4.27	4.40	4.25	4.56	4.85	5.01	5.18	5.35
Brazil[6]	2.26	2.12	2.07	2.14	2.15	2.14	2.13	2.24	2.35	2.21	2.40	2.62	2.78	2.93	3.19
Argentina	0.68	0.67	0.68	0.67	0.67	0.64	0.62	0.62	0.61	0.62	0.61	0.63	0.66	0.69	0.68
Colombia	0.93	0.95	0.94	0.97	0.95	0.99	0.98	1.01	1.04	1.01	1.14	1.12	1.10	1.10	1.03
Others	0.41	0.41	0.42	0.42	0.41	0.41	0.40	0.40	0.40	0.40	0.41	0.47	0.47	0.46	0.45
Middle East[4]	1.40	1.46	1.50	1.49	1.46	1.43	1.46	1.46	1.45	1.45	1.42	1.37	1.29	1.26	1.32
Oman	0.89	0.91	0.93	0.95	0.92	0.93	0.95	0.97	0.97	0.96	1.00	0.97	0.95	0.94	0.93
Syria	0.17	0.16	0.16	0.16	0.16	0.13	0.12	0.12	0.11	0.12	0.09	0.09	0.06	0.07	0.16
Yemen	0.14	0.18	0.21	0.19	0.18	0.18	0.19	0.18	0.18	0.18	0.16	0.13	0.11	0.09	0.08
Others	0.20	0.20	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.17	0.17	0.16	0.16	0.15
Africa	2.43	2.26	2.25	2.29	2.31	2.31	2.33	2.36	2.48	2.37	2.51	2.50	2.48	2.58	2.65
Egypt	0.74	0.74	0.73	0.73	0.73	0.73	0.72	0.71	0.70	0.71	0.69	0.69	0.68	0.67	0.65
Equatorial Guinea	0.29	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.30	0.29	0.32	0.31	0.29	0.27	0.26
Sudan	0.10	0.06	0.07	0.10	0.08	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.08	0.07	0.06
Others	1.30	1.18	1.17	1.19	1.21	1.19	1.21	1.25	1.38	1.26	1.39	1.42	1.43	1.57	1.67
Total Non-OECD	29.79	29.24	29.32	29.76	29.53	29.70	29.47	29.42	29.85	29.61	30.07	30.55	30.64	30.78	30.89
Processing Gains[5]	2.14	2.11	2.16	2.13	2.14	2.18	2.16	2.20	2.18	2.18	2.21	2.26	2.29	2.33	2.38
Global Biofuels[6]	1.54	1.85	2.13	1.88	1.85	1.51	1.93	2.30	2.05	1.95	2.10	2.23	2.30	2.34	2.36
TOTAL NON-OPEC[2]	53.35	52.85	52.99	54.22	53.35	53.94	53.90	54.51	55.34	54.43	55.79	57.03	57.84	58.62	59.31
TOTAL SUPPLY	90.83	90.76	90.86	91.52	90.99	90.84									

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*				Russia	Messoyakha	125	2017
USA	Caesar	40	2012	Italy	Tempa Rossa	50	2015	Russia	Bazhenov layer (incl Priobskoye)	200	2017-18
USA	Who Dat	55	2012	Denmark	Hejre	40	2016	Russia	Gazprom Condensate	170	ongoing
USA	Liberty	40	2013	Norway	Skarv	80	2013	Kazakhstan	Kashagan phase 1a	375	2013
USA	Axe & Dalmation	10	2013	Norway	Goliat	100	2014	Azerbaijan	West Chirag Oil	150	2014
USA	Knotty Head	20	2013	Norway	Gudrun/Sigrun	70	2014	*Asia*			
USA	Stones	80	2013	Norway	Knarr (Jordbaer)	25	2014	India	Vasai West and Bombay High redev.	100	2017
USA	Big Foot	75	2014	Norway	Ekofisk extension	50	2015	India	Rajasthan Block: Mangala, Aishwariya, Bhagyam	150	ongoing
USA	Lucius	70	2014	Norway	Eldfish extension	20	2015	Indonesia	Banu Urip	150	2014
USA	Great White (incr)	40	2014	Norway	S Trost	15	2015	Indonesia	Gendalo Gehem	100	2015
USA	Gunflint/Freedom	120	2015	Norway	Edvard Grieg	80	2015	Malaysia	Gumusut	130	2013
USA	Jack/St Malo	170	2015	Norway	Froy redevelopment	35	2016	Malaysia	Kebabangan	25	2015
USA	Mars B	100	2015	Norway	Draupne	20	2016	Malaysia	Malikai	50	2016
USA	Tubular Bells	100	2015	Norway	Hild	30	2016	Thailand	Manora	15	2014
USA	Vito	90	2015	Norway	Luno	30	2016	Vietnam	Dua and other Chim Sao increments & Ham Rong	40	2013
USA	Kaskida	140	2016	Norway	Dagny/Eirin	35	2017	*Latin America*			
USA	Mad Dog tie-backs	100	2018	Norway	Yme	20	2017	Brazil	Bauna and Piracaba, formerly Tiro/Sidon	80	2012
Canada	Algar Lake	11	2013	Norway	Johan Sverdrup	140	2018	Brazil	Lula, NE Pilot, FPSO Cidade Paraty	120	2013
Canada	Germain	35	2013	Norway	Other redevelopment: Hod, Ringhorne, Varg			Brazil	Papa Terra - BC-20	120	2013
Canada	Kearl Phase I	110	2013	UK	Huntington	30	2012	Brazil	Parque das Baleias P-58 (pre-salt)	175	2014
Canada	West Ells	38	2013	UK	Jasmine	35	2013	Brazil	Argonauta, Ostra (Parque das Conchas)	40	2014
Canada	Black Gold	30	2014	UK	Cheviot (former Emerald)	30	2014	Brazil	Carioca (pre-salt)	50	2015
Canada	Hangingstone	57	2014	UK	Golden Eagle	60	2014	Brazil	Piracuca (condensate)	15	2015
Canada	Kirby South Phase 1	35	2014	UK	Fyne, Solan, Andrew	60	2014	Brazil	Franco transfer of rights, P-74 & P-75	180	2016
Canada	MacKay	100	2014	UK	Emerald	25	2014	Brazil	Carimbe (tieback to Barracuda)	90	2017
Canada	Sunrise	50	2014	UK	Clair expansion	35	2015	Brazil	Iara	120	2018
Canada	Corner	75	2015	UK	West Franklin	20	2015	Brazil	Carcara	60	2018
Canada	Dover	110	2015	UK	Mariner	35	2016	Brazil	Maromba	90	2018
Canada	Dover West Clastics	50	2015	UK	Schiehallion Redevelopment/Quad 204	140	2016	Brazil	Parque das Baleias P-58 (pre-salt), Sul	150	2012-18
Canada	Kearl Phase II	80	2015	UK	Lochnagar and other Rosebank	120	2017	Brazil	Roncador Modules P-55, P-62	300	2013-14
Canada	Surmont II	80	2015	UK	Forties redevelopment	50	ongoing	Brazil	Sapinhoa, Sapinhoa Norte	250	2013-16
Canada	Taiga	30	2015	UK	Redev. (Gannett, Auk, Tweedsmuir, Thistle, Dunbar)	60	ongoing	Brazil	Tartaruga Mestica (fmr Aruana)	100	2013-18
Canada	Thickwood	30	2015	*OECD Asia Oceania*				Brazil	OGX Fields	120	2013-2016
Canada	Kirby North Phase 1	40	2016	Australia	Montara (and Skua & Swift)	35	2011	Brazil	QGEP: Atlanta EPS and Full Development	100	2014-18
Canada	Legend Lake	30	2016	Australia	Coniston	30	2013	Brazil	Lula Alto, Centro, Sul	200	2015-16
Canada	Narrows Lake	104	2016	Australia	North Rankin and Gorgon Liquids	50	2014	Colombia	Various: Cupiagua, Castilla, Chichimene, CPE-6	90	2013-17
Canada	Grand Rapids	54	2017	Australia	Balnaves and other additions	50	2014-16	*Middle East*			
Canada	Grouse SAGD Project	50	2017	*FSU*				Bahrain	Awali EOR	35	2013
Canada	Jackpine Expansion	100	2017	Russia	Bolshekhetsky	100	2013	Oman	Mukhaizna EOR	140	2012
Canada	Firebag V-VI	60	2018	Russia	Arkutun-Daginskoye	90	2014	Oman	Harweel and other PDO EOR	80	ongoing
Canada	Fort Hills I	120	2018	Russia	Novoportovskoye (yr round), Suzun	170	2014	*Africa*			
Canada	Joslyn	90	2018	Russia	Prirazlomnoye	120	2014	Congo	Moho North	100	2016
Canada	Telephone Lake	50	2018	Russia	Trebs & Titov	120	2014	Equatorial Guinea	Belinda (Alen)	40	2014
Mexico	Ayatsil	100	2014	Russia	Tsentralnoye	100	2015	Ghana	Tweneboa and Enyenra	105	2014
Mexico	Tsimin	100	2014	Russia	Vladimir Filanovsky	150	2015	Ivory Coast	Acajou	10	2017
Mexico	Xux	40	2015	Russia	Chayadinskoye	50	2015	Mauritania	Banda (Tullow)	10	2015
Mexico	Utsil	15	2015	Russia	Russkoye	150	2016	Niger	Tenere Bilma	70	2015
Mexico	Navegante	15	2015	Russia	Tagul	100	2016	Uganda	Albert Basin (Tullow/Heritage) next phases	150	2017
Mexico	Onel	15	2016	Russia	Pyakyakhinskoye	30	2016				
Mexico	Chicontepec Expansion	160	ongoing	Russia	Yurubcheno-Tokhomskoye	150	2016				

Table 3B: SELECTED 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
Crude Oil Projects								*NGL & Condensate Projects*			
Algeria	El Merk	135	2013	Iraq	Halfaya	100	2013	Algeria	MLE (Condensate)	10	2013
Algeria	Bir Seba (Blocks 433a/416b)	36	2014	Iraq	Badra	110	2013	Algeria	MLE (NGLs)	14	2013
Angola	PSVM (Block 31)	150	2012	Iraq	Gharaf	230	2013	Algeria	Tisselit Nord (Condensate)	10	2013
Angola	Kizomba D-Satellites (Block 15) Clochas & Mavacola	140	2012	Iraq	Halfaya	100	2013	Algeria	Hassi Messaoud (LPG)	50	2012
Angola	Sangos/N'Goma (Block 15)	85	2014	Iraq	Zubair Phase 2	200	2017	Algeria	El Merk (Condensate)	30	2013
Angola	Platino, Chumbo, Cesio (Block 18W)	150	2013	Libya	Area 47 Ghadames Basin	50	2018	Algeria	El Merk (NGLs)	31	2013
Angola	SE PAJ (Block 31)	150	2014	Nigeria	Usan	180	2012	Algeria	Gassi Touil (NGLs)	10	2013
Angola	CLOV (Block 17)	160	2014	Nigeria	Zabazaba/Etan	120	2015	Angola	Soyo LNG Project (Condensate)	10	2013
Angola	Cabaca Norte-1 (Block 15)	40	2014	Nigeria	Erha North	50	2015	Angola	Soyo LNG Project (NGLs)	50	2013
Angola	Malange	50	2015	Nigeria	Bonga SW & Aparo	140	2016	Angola	Mafumeira Sul (NGLs)	10	2015
Angola	Lianzi (Congo-Brazzaville joint zone)	45	2015	Nigeria	Bonga NW	50	2016	Iran	Pars 9&10 (Condensate)	20	2013
Angola	Mafumeira Sul (Block 0)	110	2015	Nigeria	Nsiko	100	2016	Iran	Pars 9&10 (NGLs)	20	2013
Angola	Negage	50	2015	Nigeria	Egina	200	2017	Iran	Pars 12 (Condensate)	20	2015
Angola	Gindungo, Canela, Gengibre (Block 32)	150	2016	Nigeria	Bosi	135	2017	Iran	Pars 12 (NGLs)	6	2015
Angola	Lucapa (Block 14)	100	2016	Nigeria	Uge	110	2017	Iran	Kharg NGL	20	2015
Angola	Cinguvu\Nzanza	40	2016	Qatar	Duhkan	75	2015	Iraq	Khor Mor Gas Field (Condensate)	15	2012
Angola	Mostrado, Cola, Salsa, Manjericao (Block 32)	90	2017	Qatar	Bul Hanine increment	50	2016	Iraq	Khor Mor Gas Field (NGL)	10	2012
Angola	Chissonga (Block 16)	150	2017	Saudi Arabia	Manifa 1	500	2013	Libya	NC-98 Condensate	100	2015
Angola	Platino, Chumbo, Cesio (PCC) (Block 18W)	150	2018	Saudi Arabia	Manifa 2	400	2014	Nigeria	OKLNG (NGLs)	30	2017
Angola	Negage (Block 14)	50	2018	Saudi Arabia	Khurais Expansion	300	2016	Nigeria	Gbaran/Ubie (Condensate)	20	2017
Ecuador	Pungarayacu–Phase 1	30	2015	Saudi Arabia	Shaybah Expansion	250	2016	Qatar	Barzan (Condensate)	23	2013
Ecuador	Pungarayacu–Phase 2	25	2018	UAE	Lower Zakum expansion	125	2013	Saudi Arabia	Manifa (Condensate)	65	2014
Iran	Paranj	25	2013	UAE	ADCO Onshore-Sahil, Asab, Shah	65	2013	Saudi Arabia	Hasbah NGLs	30	2014
Iran	Yaran	12	2014	UAE	ADCO Onshore Qusawirah\Bidah al Qemzan	65	2013	Saudi Arabia	Shaybah (NGLs)	240	2013
Iran	Foroozan	60	2014	UAE	Nasr	65	2015	UAE	IGD–Integrated Gas Dev. (Condensate)	30	2013
Iran	Azadegan	75	2015	UAE	Umm al Lulu	100	2016	UAE	IGD–Integrated Gas Dev. (NGLs)	110	2013
Iran	Yadavaran I	85	2015	UAE	Upper Zakum expansion	200	2016	UAE	Habshan-5 (Condensates)	120	2013
Iran	South Pars	35	2015	UAE	Satah al Razboot (SARB)	100	2018	UAE	Habshan-5 (NGLs)	80	2013
Iraq	Rumaila	400	2013	Venezuela	Junin Block 2-PetroVietnam	200	2012	UAE	Shah Sour Gas (Condensates)	35	2015
Iraq	Majnoon	200	2013	Venezuela	Junin Block 4–CNPC	400	2013	UAE	Shah Sour Gas (NGLs)	32	2015
Iraq	Badra	110	2013	Venezuela	Junin Block 5–ENI	240	2013	*GTL Projects*			2013
Iraq	Gharaf	230	2013	Venezuela	Carabobo 1	400	2016	Nigeria	Escravos GTL	33	2013

Table 4
WORLD REFINERY CAPACITY ADDITIONS*

(thousand barrels per day)

	2013	2014	2015	2016	2017	2018	Total
Refinery Capacity Additions and Expansions[1]							
OECD North America	105	29	75				209
OECD Europe	-326				214		-112
OECD Pacific	-60	-499					-559
FSU	162	48	160	215			585
Non-OECD Europe							
China	730	270	1 000	1 460	400	440	4 300
Other Asia	300	272	-185		525	380	1 292
Latin America	-226	285	175	98	215	765	1 312
Middle East	531	20		358	465	731	2 105
Africa	40	46		95	195		376
Total World	1 257	471	1 225	2 226	2 014	2 316	9 508
Upgrading Capacity Additions[2]							
OECD North America	60	221	64				345
OECD Europe	-40		115		106		181
OECD Pacific	18	-46		80			52
FSU	195	154	183	150	90	95	866
Non-OECD Europe		75	134				209
China	462	112	231	642		90	1 537
Other Asia	317	161	20		180	31	709
Latin America	-26	60	170	20	247	260	731
Middle East	394	196	40	95	241	221	1 187
Africa					107		107
Total World	1 380	932	957	987	971	697	5 923
Desulphurisation Capacity Additions[3]							
OECD North America	240	85	60				385
OECD Europe	-200		35		114		-51
OECD Pacific	-89	-82					-170
FSU	114	160	50	35			359
Non-OECD Europe		45	20				65
China	799	139	331	850		164	2 283
Other Asia	284	104	- 98		284	10	583
Latin America	90	111	160		70	245	676
Middle East	466	30	40	222	262	446	1 465
Africa	95	37			42		174
Total World	1 799	630	598	1 106	772	865	5 769

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.
* New OECD members Chile and Israel are still accounted for in Latin America and Middle East, respectively. Estonia and Slovenia have no refineries.

Table 4A
WORLD REFINERY CAPACITY ADDITIONS*: Changes from Last Medium-Term Report

(thousand barrels per day)

	2012	2013	2014	2015	2016	2017	Total
Refinery Capacity Additions and Expansions[1]							
OECD North America							
OECD Europe					-200	214	36
OECD Pacific			-105				-105
FSU							
Non-OECD Europe							
China	202	240	-410	400	790	100	1 452
Other Asia		-120	120	-265		275	10
Latin America					-50	50	
Middle East	-120	80	-417	-400		400	-386
Africa							
Total World	82	200	-812	-265	540	1 039	1 007
Upgrading Capacity Additions[2]							
OECD North America		-71	71				
OECD Europe				-106		106	5
OECD Pacific							
FSU		-25		25			
Non-OECD Europe			41	84			125
China	107	23	-213	-66	447		258
Other Asia				-105		90	-15
Latin America		35			-84	117	68
Middle East	-88	94	-217	-241		241	-186
Africa						50	50
Total World	19	57	-319	-409	363	604	305
Desulphurisation Capacity Additions[3]							
OECD North America							
OECD Europe						114	115
OECD Pacific							
FSU		-30		30			
Non-OECD Europe	-20			20			
China	58	330	-232	-229	597		488
Other Asia				-124		104	-20
Latin America					-30	30	
Middle East	- 209	221	-220	-262	50	262	-118
Africa			37				37
Total World	-171	521	-415	-565	617	510	502

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.

* New OECD members Chile and Israel are still accounted for in Latin America and Middle East, respectively. Estonia and Slovenia have no refineries.

Table 4B: SELECTED REFINERY CRUDE DISTILATION PROJECT LIST

Country	Project	Capacity (kbd)[1]	Start Year	Country	Project	Capacity (kbd)1	Start Year
OECD North America							
Canada	North West Redwater Partnership - Edmonton	50	2015	China	Sinopec/KPC - Zhanjiang, southern Guangdong	300	2016
United States	BP PLC - Whiting	20	2013	China	CNPC/Qatar Petroleum/Shell - Zhejiang / Taizhou	400	2017
United States	ConocoPhillips - Billings	10	2013	China	Sinopec/Saudi Aramco/exxonmobil - Quanzhou, fujian	240	2018
United States	ConocoPhillips - Borger	50	2013	China	China National Petroleum Corp. - Wanzhou	200	2018
United States	Valero Energy Corp. - Sunray	25	2013	*Other Asia*			
United States	National Cooperative Refining Assoc. - McPherson	15	2014	Bangladesh	BPC / KPI - Chittagong	80	2017
United States	Holly Corp. - Woods Cross	14	2014	China, Taiwan	Chinese Petroleum Corp. - Kaohsiung	-205	2015
United States	Western Refining Inc. - El Paso	25	2015	India	Indian Oil Co. Ltd. - Paradip	300	2013
OECD Europe				India	Nagarjuna oil Co - Cuddalore	120	2014
France	Petroplus - Petit Couronne	-162	2013	India	Indian Oil Co. Ltd. - Koyali, Gujarat	80	2018
Germany	Shell - Harburg	-110	2013	Malaysia	Petronas - Rapid Pengerang	300	2018
Hungary	MOL Hungarian Oil & Gas Co. - Szazhalombatta	26	2013	Pakistan	Attock Refinery Ltd. - Rawalpindi	12.4	2014
Italy	Eni - Porto Marghera	-80	2013	Pakistan	IPIC/PARCO - Khalifah Coastal Refinery	250	2017
Turkey	Turcas Petrol+SOCAR - Aliaga/Izmir	214	2017	Thailand	Thai Oil Co. Ltd. - Sriracha	30	2014
OECD Pacific				Thailand	PTT PLC - Bangchak Bangkok	20	2015
Australia	Caltex Refineries (NSW) Ltd. - Kurnell	-124	2014	Vietnam	Petro vietnam/KPC/Idemitsu Kosan - Nghi Son	195	2017
Japan	Cosmo Oil Co. Ltd. - Sakaide	-110	2013	*Middle East*			
Japan	Idemitsu Kosan Co. Ltd. - Shunan, Yamaguchi (Tokuyama)	-120	2014	Iran	National Iranian Oil Co. - Arak	80	2013
Japan	JX Energy - Unidentified	-200	2014	Iran	National Iranian Oil Co. - Lavan Island	21	2013
Japan	Tonen/General Sekiyu Seisei KK - Kawasaki	-67	2014	Iraq	INOC-ORA - Karbala	140	2016
Japan	Tonen/General Sekiyu Seisei KK - Wakayama	-38	2014	Kuwait	Kuwait National Petroleum Co. - Mina Abdulla	147	2018
Non-OECD Europe				Kuwait	Kuwait National Petroleum Co. - Mina al-Ahmadi	-86	2018
FSU				Oman	Sohar Bitumen Refinery - Sohar	30	2013
Chechen Republic	Rosneft - Grozny	20	2015	Oman	Oman Refinery Co. - Sohar	72	2016
Kazakhstan	Kazmunigas - Atyrau	48	2014	Oman	Oman Refinery Co. - Al-Duqm	150	2018
Russia	Alliance Co. - Khabarovsk	20	2013	Saudi Arabia	SATORP (Saudi Aramco Total Refining and Petrochemical CO) - Jubail	400	2013
Russia	Rosneft - Tuapse	140	2013	Saudi Arabia	Saudi Aramco - Rabigh 2	50	2017
Russia	Lukoil - Volgograd	120	2015	Saudi Arabia	Saudi Aramco - Jizan	400	2017
Russia	West Siberian Oil Refinery - Tomsk	60	2015	Saudi Arabia	Aramco Sinopec - Yanbu	400	2018
Russia	Verkhoturye - Sverdlovsk	60	2015	UAE-Abu Dhabi	Abu Dhabi National Oil Co. - Ruwais2	417	2015
Russia	Lukoil - Volgograd	-100	2015	UAE-Dubai	Emirates National Oil Co. - Jebel Ali	20	2014
Russia	Lukoil - Kstovo, Nizhny Novgorod	95	2016	Yemen	Yemen - Hunt - Marib	15	2017
Russia	Antipinsky Refinery - Antipinsky	120	2016	*Latin America*			
China				Argentina	Repsol YPF SA - La Plata	25	2013
China	China National Petroleum Corp. - Huabei	100	2013	Aruba	Valero Aruba Refinery - San Nicolas	-271	2013
China	Sinopec - Anqing	70	2013	Brazil	Petrobras (Premium I) - Maranhao	300	2018
China	Sinopec/Saudi Aramco/exxonmobil - Quanzhou, fujian	40	2013	Brazil	Petrobras (Premium II) - Ceara	300	2018
China	Sinopec - Wuhan	20	2013	Brazil	Petrobras/Petroleos de Venezuela SA - Pernambuco State Abreu e Lima	115/115	2014/2015
China	Sinochem (KPC+Shell 24.5% ?) - Quanzhou Fujiang	240	2013	Brazil	Petrobras/Petroleos de Venezuela SA - COMPERJ	165/165	2017/2018
China	Sinopec - Yangzi	60	2013	Colombia	Empresa Colombiana de Petroleos - Cartagena, Bolivar	85	2014
China	China National Petroleum Corp. - Pengzhou	200	2013	Colombia	Empresa Colombiana de Petroleos - Barrancabermeja-Santander	50	2017
China	Sinopec - Jiujiang	70	2014	Costa Rica	Recope/CNPC - Limon	65	2016
China	Sinopec - Shijiazhuang	60	2014	Cuba	Cuba Petroleos - Cienfuegos	85	2014
China	CNOOC/Local Ningbo Daxie - Zhejiang	140	2014	Jamaica	Petrojam Ltd. - Kingston	20	2013
China	CNPC/Rosneft - Tianjin	260	2015	Peru	Petroperu SA - Talara, Piura	33	2016
China	Sinopec - Caofeidian	240	2015	Venezuela	Petroleos de Venezuela SA - Santa Inés (Barinas)	60	2015
China	China National Petroleum Corp. - Kunming/Anning	200	2015	*Africa*			
China	China National Petroleum Corp. - Jinxi	200	2015	Algeria	Naftec SPA - Skikda	40	2013
China	China National Petroleum Corp. - Fushun	70	2016	Algeria	Sonatrach - Algiers	18	2014
China	China National Petroleum Corp. - Daqing Heilongjiang	90	2016	Algeria	Naftec SPA - Arzew	75	2016
China	China National Petroleum Corp. - Karamay, Xinjiang	100	2016	Algeria	Naftec SPA - Skikda	75	2017
China	Sinopec - Zhenhai	300	2016	Angola	Sonangol - Lobito	120	2017
China	CNOOC - Huizhou	200	2016	Cameroon	SONARA - Cape Limboh Limbe	28	2014
China	CNPC/PDVSA - Jieyang, Guangdong	400	2016	Uganda	Tullow -JV - Albertine Graben	20	2016

Table 5
WORLD ETHANOL PRODUCTION[1]

(thousand barrels per day)

	2012	2013	2014	2015	2016	2017	2018
OECD Americas[2]	894	884	953	991	1 008	1 008	1 006
United States	864	853	921	955	975	977	979
Canada	29	31	31	35	33	29	26
OECD Europe[3]	67	77	90	94	98	100	100
Austria	2	2	2	2	2	2	2
Belgium	6	6	6	6	6	6	6
France	13	15	18	18	20	20	20
Germany	14	13	14	15	15	15	15
Italy	1	2	3	3	3	3	3
Netherlands	4	5	5	6	6	6	6
Poland	5	5	6	6	7	7	7
Spain	7	8	9	9	9	9	9
UK	5	8	11	12	14	15	15
OECD Asia Oceania[4]	7	8	10	10	11	11	12
Australia	7	8	9	9	9	10	10
Total OECD	**968**	**970**	**1 053**	**1 095**	**1 117**	**1 119**	**1 118**
FSU	3	2	2	3	3	3	4
Non-OECD Europe	1	1	1	1	1	1	1
China	41	46	52	53	54	55	55
Other Asia	27	36	42	46	47	51	52
India	8	10	11	12	12	13	13
Indonesia	1	2	2	3	3	3	4
Malaysia	0	0	0	0	0	0	0
Philippines	3	3	5	6	7	9	9
Singapore	1	1	1	1	1	1	1
Thailand	11	14	15	15	15	17	17
Latin America	405	459	482	522	552	563	571
Argentina	4	5	8	8	10	10	10
Brazil	386	436	452	492	519	530	536
Colombia	6	7	8	8	8	8	9
Middle East	0	0	0	0	0	0	0
Africa	3	5	6	8	10	10	11
Total Non-OECD	**482**	**549**	**585**	**634**	**668**	**684**	**695**
Total World	**1 450**	**1 520**	**1 638**	**1 728**	**1 785**	**1 803**	**1 813**

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)

	2012	2013	2014	2015	2016	2017	2018
OECD Americas[2]	65	89	90	90	89	89	88
United States	63	84	84	84	84	84	84
Canada	2	5	6	6	5	5	4
OECD Europe[3]	163	161	172	195	199	204	206
Austria	3	4	4	4	4	4	4
Belgium	6	6	7	7	7	7	7
France	32	35	38	39	39	39	39
Germany	52	42	44	49	51	51	51
Italy	9	9	9	11	11	11	11
Netherlands	8	8	10	11	11	12	12
Poland	5	5	6	6	7	7	7
Spain	11	14	16	20	20	24	24
UK	3	4	4	5	5	6	6
OECD Asia Oceania[4]	8	9	10	10	11	11	12
Australia	2	2	3	3	4	4	4
Total OECD	**236**	**260**	**272**	**294**	**299**	**304**	**305**
FSU	1	1	1	1	1	1	1
Non-OECD Europe	3	3	3	3	3	3	3
China	4	5	6	6	7	7	9
Other Asia	59	60	64	67	71	78	81
India	1	1	2	2	2	3	3
Indonesia	26	21	23	23	23	24	26
Malaysia	5	6	6	7	8	10	8
Philippines	3	4	4	4	4	5	5
Singapore	13	15	15	16	18	18	19
Thailand	12	13	14	16	16	18	19
Latin America	106	100	112	125	134	142	146
Argentina	47	40	42	46	51	51	54
Brazil	47	48	57	65	68	76	76
Colombia	7	7	8	9	10	10	11
Middle East	0	0	0	0	0	0	0
Africa	0	1	3	4	4	5	5
Total Non-OECD	**173**	**170**	**188**	**205**	**220**	**236**	**244**
Total World	**409**	**429**	**460**	**500**	**518**	**540**	**549**

1 Volumetric production; to convert to energy adjusted production, biodiesel is assumed to have 90% energy content of conventional diesel.

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 5B: SELECTED BIOFUEL PROJECT START-UPS

Country	Project	Output	Capacity (kbd)	Capacity (mly)	Start Year
OECD Americas					
USA	KiOR - Columbus, Mississippi	synthetic gasoline	1	50	2012
USA	Diamond Green - Norco, Los Angeles	biodiesel (hydrotreated)	9	520	2013
USA	AltAir/ Tesoro - Anacortes, Washington	biodiesel (hydrotreated)	7	380	2013
USA	Renewable Energy Groupd - Emporia, Kansas	biodiesel	4	230	2013
USA	Renewable Energy Groupd - St Rose, Louisiana	biodiesel	4	230	2013
USA	Abengoa Bioenergy - Hugoton, Kansas	cellulosic-ethanol	2	95	2013
USA	POET - Emmetsburg, Iowa	cellulosic-ethanol	2	95	2013
USA	Dupont - Nevada, Iowa	cellulosic-ethanol	2	105	2014
USA	BP Biofuels - Highlands County, Florida	cellulosic-ethanol	2	135	Cancelled
Canada	Great Lakes Biodiesel - Welland, ON	biodiesel	3	170	2012
Canada	Lignol - Vancouver, British Columbia	cellulosic-ethanol	1	75	2015e
Canada	Mascoma - Drayton, Alberta	cellulosic-ethanol	1	75	2015e
OECD Europe					
Finland	UPM - Lappeenranta	biodiesel (hydrotreated)	2	110	2014
Finland	Forest BtL Oy - Ajos	synthetic diesel, biokerosen	2	130	2016e
France	UPM - Strasbourg	synthetic diesel	2	120	2015
Hungary	Pannonia Ethanol - Dunafoldvar	ethanol	4	250	2012
Italy	Chemtex - Piedmont	cellulosic-ethanol	1	76	2012
Netherlands	Woodspirits - Delfzijl	cellulosic-methanol	5	290	2016e
Switzerland	Green Bio Fuel Switzerland - Bad Zurzach, Aargau	biodiesel	2	135	2014
UK	Vivergo - Hull	ethanol	7	420	2012
Asia					
Australia	National Biodiesel - Port Kembla, New South Wales	biodiesel	5	290	2013
China	COFCO/Sinopec - Shuangcheng	cellulosic-ethanol	1	63	2013
Indonesia	Perkebunan Nusantara & Ferrostaal Indonesia - Sei Mangkei	biodiesel	5	280	2014
Latin America					
Argentina	Louis Dreyfus - General Lagos	biodiesel	6	340	2012
Argentina	ACA Bio - Cordorba	ethanol	3	120	2013
Argentina	Green Pampas - Timbues	ethanol	7	380	2014e
Brazil	Tres Tentos Agorindustrial - Rio Grande	biodiesel	3	180	2013
Brazil	Solazymes - Moema	biodiesel (algae)	2	125	2013
Brazil	GraalBio - Alagaos	cellulosic-ethanol	1	80	2014
Brazil	Raizen Energia	cellulosic-ethanol	1	40	2014
Brazil	Vale SA - Para	biodiesel	7	405	2015e

Table 6: NORTH AMERICAN CRUDE OIL RAIL TERMINALS LIST

Location	Company	Capacity (kbd) 2012	2013	2014	2015	Location	Company	Capacity (kbd) 2012	2013	2014	2015	LTO/Heavy
Onload Rail Capacity						Various sites (Edmonton, Estevan, Calmar, AB...)	CP					
Williston Basin						Fort Saskatchewan, AB	CN					
Stanley, ND	EOG Rail	65	65	65	65	Edmonton, AB	Gibson					
New Town, ND	Dakota Plains	30	30	80	80							
Various sites (Minot, Dore, Donnybrook, ND...)		30	30	30	30	*Receiving Rail Capacity*						
Epping, ND	Inergy COLT Hub	120	120	120	120	*US Gulf Coast*						
Tioga, ND	Hess Rail	60	60	60	60	St. James, LA	Plains (former USDG)	130	140	140	140	LTO
Dickinson, ND	Bakken Oil Express	100	100	100	100	St. James, LA	NuStar/EOG	80	140	140	280	LTO
Trenton, ND	Savage Services	90	90	90	90	St. James, LA	Nustar		70	140	140	LTO
Berthold, ND	Enbridge	10	80	80	80	Sites in Baton Rouge, LA and Seabrook, TX	LBC Tank Terminals					
Fryburg, ND	Great Northern Midstream		60	60	60	Sunshine, LA	CN/LBC Tank Terminals					Heavy
Dore, ND	Musket	60	60	60	60	Mobile, AL	CN/ARC		75	75	75	LTO/Heavy
Ross, ND	Plains	20	65	65	65	Natchez, MS	CN/Genesis		15	40	40	Heavy
New Town, ND	Plains/Van Hook	35	65	65	65	Walnut Hill, FL	Genesis Energy		75	75	75	LTO
Zap, ND	Global/Basin Transload	40	40	40	40	Geismar, LA	Crosstex Energy	5	15	15	15	LTO
Fairview, MT	Northstar Transloading			100	100	Baton Rouge, LA	Genesis Energy			65	65	LTO/Heavy
Niobrara						Osceola, AR	Indigo Resources			140	140	LTO/Heavy
Carr, CO	Plains	15	30	30	30	Port Arthur, TX	GT Logistics	100	100	100	100	LTO
Tampa, CO	Plains		65	65	65	Hayti, MO	Marquis Energy	70	140	140	140	LTO
Casper, WY	Granite Peak/Cogent		80	80	80	St. Louis, MO	Seacor Holdings	70	70	70	70	LTO
Douglas, WY	Enserco		60	120	120	St. James Parish, LA	Petroplex/Macquarie			70	70	LTO
Guersney, WY	Eight Eight Co		60	60	60	Houston, TX	Watco/Kinder Morgan/Martin Midstream			210	210	LTO/Heavy
Windsor, CO	Musket Corp.	10	30	30	30	Beaumont, TX	Jefferson Refinery		70	70	70	LTO
Hudson, CO	Hudson Terminal Railroad		6	6	6	Hull, TX	Keyera			50	50	Heavy
Eagle Ford						Corpus Christi, TX	Trafigura	30	30	30	30	LTO
Gardendale, TX	Plains		40	40	40	*US East Coast*						
Harwood, TX	EOG	45	45	45	45	Albany, NY	Global Partners	50	50	160	160	LTO
Live Oak, TX	Howard Energy					Albany, NY	Buckeye Partners		135	135	135	LTO
San Antonio, TX	Hondo Railroad		30	30	30	Yorktown, PA	Plains (former USDG)		130	130	130	LTO
Elmendorf, TX	Frontier logistics					Westville (Eagle Point), NJ	Sunoco Logistics/Carlyle	45	140	140	140	LTO
La Feria, TX	Atlas Oil					Philadelphia (Eddystone), PA	Enbridge/Canopy Prospecting Inc.		80	160	160	LTO
Permian Basin						Delaware, PA	PBF Energy	40	110	110	110	LTO/Heavy
Barnhart, TX	EOG	2	2	2	2	New Brunswick (Saint John), QU	Irving Oil	70	70	70	70	LTO/Heavy
Pecos, TX	Watco/Kinder Morgan/Martin Midstream	60	60	60	60	Linden (Bayway), NJ	Phillips 66			60	60	LTO
Wink, TX	Genesis Energy		75	75	75	Perth Amboy, NJ	Buckeye Partners					LTO
Carlsbad, NM	Cetane Energy & Murex		70	70	70	*US West Coast*						
Loving, NM	Rangeland		120	120	120	Anacortes , WA	Tesoro	40	50	50	50	LTO
Various sites (Odessa, TX; Albuquerque, NM...)	Atlas oil	5	5	5	5	Bakersfield, CA	Plains			70	70	
Mesquite, TX	Crosstex					Blaine (Cherry Point), WA	BP			60	60	LTO
Anadarko and Utica						Ferndale , WA	Phillips 66	20	20	40	40	LTO
Sayre, OK	Logimarq		30	30	30	Bakersfield, CA	Alon			65	65	LTO/Heavy
Stroud, OK	EOG/Watco/KM		90	90	90	Martinez , CA	Tesoro		5	5	5	LTO
Black Run, OH	Crosstex					Grays Harbor, WA	Westway/Imperium/USDG			30	90	LTO/Heavy
Western Canada						Port of Tacoma (Sound Terminal), WA	Targa Resources		30	70	70	LTO/Heavy
Fort McMurray (South Cheecham), AB	Enbridge/Keyera		30	30	60	Benicia , CA	Valero			70	70	LTO
Hardisty, AB	Gibson			60	120	Clatskanie, OR	Global Partners	10	30	30	30	LTO
Lloydminster, AB	Altex	15	15	15	15	Tacoma , WA	US Oil and Refining	10	10	10	10	LTO
Lashburn, SK	Altex	15	15	15	15	Port of Vancouver, WA	Tesoro/Savage			120	280	LTO/Heavy
Unity, SK	Altex		15	15	15	Anacortes (Puget Sound), WA	Shell					LTO
Lynton, AB	Altex		12	12	12	Wilmington , CA	Valero					LTO
Bruderheim, AB	Canexus	8	30	70	70	Port of Prince Rupert, BC	Nexen					Heavy
Various sites (Lloydminster, AB; Bromhead, SK...)	Torq Transloading	45	100	180	180	Valdez, AK	G7 Generations Ltd					Heavy

Source: Company data, News reports, RBN Energy, IEA estimates

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