OIL REVIEW

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NATIXIS

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Natixis Commodities Research
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Abhishek has appeared on CNBC, Bloomberg TV, presented at Oil & Gas conferences and is quoted regularly by financial media globally. He has also published articles in energy journals such as Petroleum Economics. Recently he was invited to give a talk at United Nation's Global Commodities meeting in Geneva.

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Content

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Executive Summary

This Oil Review focuses upon the main markets of the Atlantic Basin countries. In addition to providing a detailed analysis of the latest developments in North America and Europe, we have also provided insights into South American oil producers. After the annexation of Crimea and subsequent escalation of tensions in Ukraine, Russian energy has become an increasingly important consideration for global markets. We have therefore included a detailed section examining the current state of Russia's oil industry.

Russia

Russian finances are heavily dependent on energy taxes, in particular mineral extraction taxes, export duties and excise duties on oil and oil products. Facing a possible downturn in crude output over the coming years, the government is seeking a balance between higher energy taxes versus fiscal incentives to encourage investment in new output. Low oil prices and the third wave of sanctions against Russia could further impact Russia's economic growth.

Growth in conventional output will slow, before moving into reverse around 2016 as depletion rates at Russia's mature fields begin to exceed additions of new capacity. To boost crude output over the medium term, Russian energy companies must invest in unconventional oil: Arctic, shale and deep-water reserves. This will require extensive financing, and it will require the application of new technology.

Russia has been "turning east" for some years now, as investment in new output and new transport infrastructure targets the expanding energy markets in Asia. The current tensions over Ukraine are helping to accelerate this process, as was evident from the major natural gas deal signed in May between Gazprom and CNPC. Over coming years, a greater proportion of Russian energy exports will increasingly be directed towards markets in Asia, reducing the availability of supplies to Europe.

Europe

Europe's economic situation remains difficult. Many of the continent's major structural problems are still unresolved, and the growing geopolitical tensions in MENA and Ukraine are damaging export markets, to the detriment of Germany's export-oriented economy in particular.

Against this bleak backdrop, European refineries continue to face huge economic challenges. While European demand for gasoil is supported by Europe's growing dependency on diesel-powered motor vehicles, this creates a natural overcapacity among other oil products, in particular gasoline. The cheapness of US crude versus Europe's Brent benchmark has in effect removed the primary export market for Europe's surplus gasoline which had previously underpinned European refiners' profitability. Worse still, growing competition from new and upgraded refineries in Middle East and Russia threatens to eat into refiners' profits from mid-distillate products. To make a bad situation worse, an imminent tightening of MARPOL and SECA rules on bunker fuel will require substantial investment from European refineries to meet the new low-sulphur requirements.

North America

US demand for oil is expected to rise by over 0.9% in 2014, slightly lower than last year's demand growth of +1.7% yoy. Demand will be driven by growth in distillates and gasoline. Demand for crude from refiners will remain high as modest growth in domestic consumption is supported by strong oil product exports (+27% yoy in 2014H1). Hence refinery operable volumes have remained high, with record utilisation rates (+2.2%pts yoy in 2014H1).

On the supply side, US crude output is expected to rise by up to 1mn b/d in 2014, similar to the rapid expansion in 2013. This is supported by the uptick in rig counts and increase in the number oil wells drilled due to improved drilling efficiencies in the first half of 2014. With increased horizontal drilling activity expected in the Permian and Eagle Ford basins, encouraged by the potential for exporting condensates, investments in US oil E&P will remain strong as long as US oil prices remain above $85-90/bbl. Higher output from the Gulf of Mexico is also expected to support overall US oil production. E&P spending in 2014 is expected to be higher than the already elevated levels experienced in 2013 and 2012.

Investment in pipelines is forecast to remain close to 2013 highs. Pipeline capacity is expected to increase by 2.8-2.9mn b/d in 2014, and with crude-by-rail volumes increasing by another 1mn b/d in 2014, we can expect increased mobilisation of US crude from well-heads to those regions which possess available refining capacity or better distribution networks.

All in all, the rapid increase in US crude oil production and limited crude exports in the near term will put a cap on US oil prices. Over time, as more companies obtain licences to export US crude, either via post-stabiliser or splitter processing, we could see crude stockpiles in PADD3 beginning to diminish. In theory, US companies could export up to 1mn b/d of condensates if they were permitted to do so. This could help to support US crude prices in 2015 relative to Brent prices.

If the US authorities fail to liberalise crude exports fast enough, there is a risk that accumulation of crude stocks in the US Gulf Coast could exhaust available storage capacity. In such a scenario, downward pressure upon LLS prices would soon feed through to downward pressure on WTI as light crude will get backed up at Cushing, especially during non-peak season.

Canadian investment in E&P is expected to increase once again in 2014, after a drop in 2013 as companies focused instead on expanding the transportation infrastructure. In 2013, spending on pipelines and rail network increased as crude take-away capacity represented a major bottle-neck in Canada, with the vast majority of export demand emanating from the US.

In 2014, Canada-US pipeline capacity is unlikely to rise as much as had been expected, since most of the projects have been delayed to 2015 or beyond. In 2015, pipeline capacity additions are expected to be add somewhere between 350-700,000b/d. Crude-by-rail volumes could increase by more than 76,000b/d in both 2014 and 2015 depending on developments in rail infrastructure.

With only a limited increase in take-away capacity, the discount of WCS to WTI is expected to decline marginally from highs of $21.2/bbl in 2013Q4 to somewhere around $18.5/bbl by the end of 2014.

In **Mexico**, the brave reforms initiated by President Enrique Pena Nieto offer potential salvation for Pemex and the Mexican energy industry over the medium term. However, in the short term, they also serve to highlight the dangerous deterioration in Pemex's financial integrity, after a decade of investment which has added little to either current or potential output. This weakness has been compounded by Pemex's growing army of past and present employees, necessitating a proposed restructuring of Pemex's pension system to reduce its outstanding financial obligations.

Given the fall in investment that has occurred over the past few months as Pemex waits to see which of its existing assets it will be allowed to retain, the main near-term risk is a drop in Mexican crude output. While this is unlikely to be nearly as extreme as the drop associated with the rapid decline of Cantarell production, we could nevertheless envisage a decline in Mexican crude output of as much as 200,000b/d between 2013-15.

South America

Brazil's oil industry has underperformed for a number of years, with output declining since the peak in late-2010/early-2011. Despite expectations for a strong rebound in output during 2014, the first half of the year has delivered another disappointing result. However, the headline numbers obscure a widening disparity between on-going weakness in conventional oil output versus rapidly expanding pre-salt output. The development of its pre-salt fields is clearly one of the strongest features of the Brazilian energy industry, and this could indeed lead to an acceleration in Brazilian crude output from 2015 onwards.

Colombia has experienced a great deal of success over the past decade in expanding its energy output, as a restructured energy industry has benefited from the advantages of increased private sector involvement. These gains may prove increasingly difficult to sustain, however, particularly if the government is unsuccessful in its efforts to negotiate peace with the country's various armed guerrilla factions.

Venezuela may have the largest crude reserves in the world, but acute economic mismanagement is preventing the country from achieving even a fraction of its energy potential. Under circumstances in which sovereign default would otherwise have been inevitable, Venezuela's finances are currently being propped up by Chinese credit. While this helps to preserve the flow of cheap crude exports to China, its perpetuation of the economic status quo is nevertheless proving detrimental to those (mainly Chinese) energy companies which are attempting to develop the country's vast Orinoco Belt reserves.

Oil Price Outlook

We expect Brent to average $107.9/bbl in 2014 and $106.7/bbl in 2015. Oil prices will be driven mainly by the rising non-OPEC supply growth, which is expected to outpace the growth in global oil demand. Geopolitical risks will continue to play an important role in determining global oil prices.

Russia

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Growth in conventional output will slow, before moving into reverse around 2016 as depletion rates at Russia's mature fields begin to exceed additions of new capacity. To boost crude output over the medium term, Russian energy companies must invest in unconventional oil: Arctic, shale and deep-water reserves. This will require extensive financing, and it will require the application of new technology.

Russia has been "turning east" for some years now, as investment in new output and new transport infrastructure targets the expanding energy markets in Asia. The current tensions over Ukraine are helping to accelerate this process, as was evident from the major natural gas deal signed in May between Gazprom and CNPC. Over coming years, a greater proportion of Russian energy exports will increasingly be directed towards markets in Asia, to the detriment of supplies to Europe.

Macroecomic Outlook

The Russian economy expanded by +0.9% yoy in 2014Q1 and +0.8%yoy in 2014Q2. Despite this growth, we expect the Russian economy to contract by -0.6% over the year as a whole due to the latest round of sanctions that was imposed on Russia by the west and the counter-sanctions imposed by Russia in return. In 2015 we project a growth rate of +0.6%, although this could be revised downwards if oil prices remain low and current developments continue to deteriorate further. In contrast, the IMF retains a more optimistic view and expects the Russian economy to expand by +0.2% yoy in 2014 and +1% yoy in 2015.

The third wave of sanctions imposed on Russia is targeted at three main areas:

- Limiting access to capital markets for Russia's state controlled financial institutions and major energy companies;
- Curtailing Russia's access to certain oil-field technologies and;
- Introducing trade restrictions, especially on arms and dual use goods.

All of them undermine Russia's growth prospects, which together with high interest rates (Russia's key rate at 8.0%), restricted access to international capital markets and massive capital outflows (estimated at $74.6bn over 2014H1) are clearly detrimental for the Russian economy.

A slowdown has already been noted in various sectors, with industrial production and manufacturing slowing to 0.4% yoy and 0.3% yoy respectively in June 2014 and production of utilities contracting by 0.8% yoy in the same month. The prospect of these sectors showing any improvement remains limited due to gradual broadening of sanctions. The Ruble remains weak, and together with an expected acceleration in food prices, this is likely to lead to a significant rise in inflation, which will in turn weigh on consumption and GDP in Russia.

Russia's oil sector

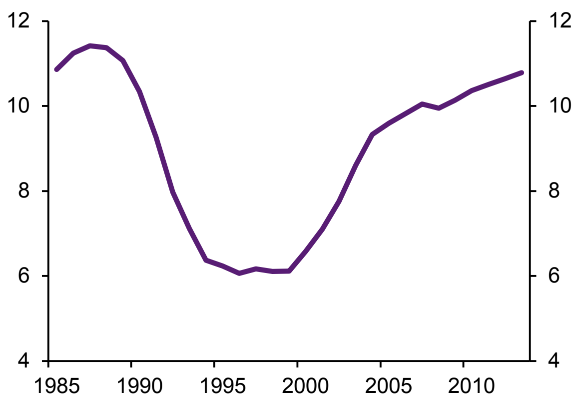
Reserves

According to the Oil and Gas Journal, Russia's proven oil reserves are estimated to be 80bn bbl (8th largest crude oil reserve). However, this amount might be underestimated, since the country has a significant reserve of shale oil (the biggest reserve in the world with 75bn bbl of recoverable resources, according to Platts' 2013 estimate) and substantial potential in its arctic reserves in areas such as the Kara Sea where Exxon is involved, which potentially hold 45bn boe of oil resources, according Rosneft, which plans to drill its first well this year.

Oil Production

According to ESAI, Russia produced 10.46mn b/d of oil (up 1% yoy) in 2013, which represented 13% of world production. Most of Russia's oil is currently produced in the West Siberia region (around 6.4mn b/d in 2012) and the Urals-Volga (which produced around 2.3mn b/d in 2012). The rest of the country's production is located variously in East Siberia (including the Vankor Field, launched in 2009, providing nearly 400,000b/d in 2013), the Yamal Peninsula, the North Caucasus, Timan Pechora and Sakhalin Island (where Exxon Mobil and Shell have a stake in Sakhalin I and Sakhalin II projects).

Russia crude oil production (mn b/d)



Sources: Natixis, BP

Projects to develop three large deposits were launched last year; Trebs and Titov in West Siberia, Srednebotuobinskoe in eastern Siberia and the Arctic Prirazlomnoye. According to Lukoil, which is involved in the projects with Bashneft, the Trebs and Titov fields are expected to start commercial production in 2016, providing 100,000b/d by 2020. The Srednebotuobinskoe project includes Rosneft and CNPC, and this field is expected to provide 20,000b/d in 2014 and 100,000b/d from 2017. The Prirazlomnoye field is being developed by Gazprom and has the capacity to produce 130,000b/d. Production in the Prirazlomnoye field started in December 2013. The Yurubcheno-Tokhomskoye field (0.1bn of boe with a peak output of 200,000b/d) is expected to come on-stream in 2016.

Maintaining oil revenue is critical to the Kremlin's projection of Russian power, with around half of government income being generated from oil. In 2010, the energy ministry warned that without big policy changes, particularly in the sphere of taxation, production could fall to 7.7mn b/d by 2020 from 10.1mn b/d in 2010, as decline rates from Russia's large, ageing fields will begin to accelerate while conventional greenfield projects are unlikely to be able to replace this lost output.

The government has therefore embarked on a dual path of raising revenue from existing oil and gas output, while at the same time attempting to incentivise development of new unconventional oil and gas reserves.

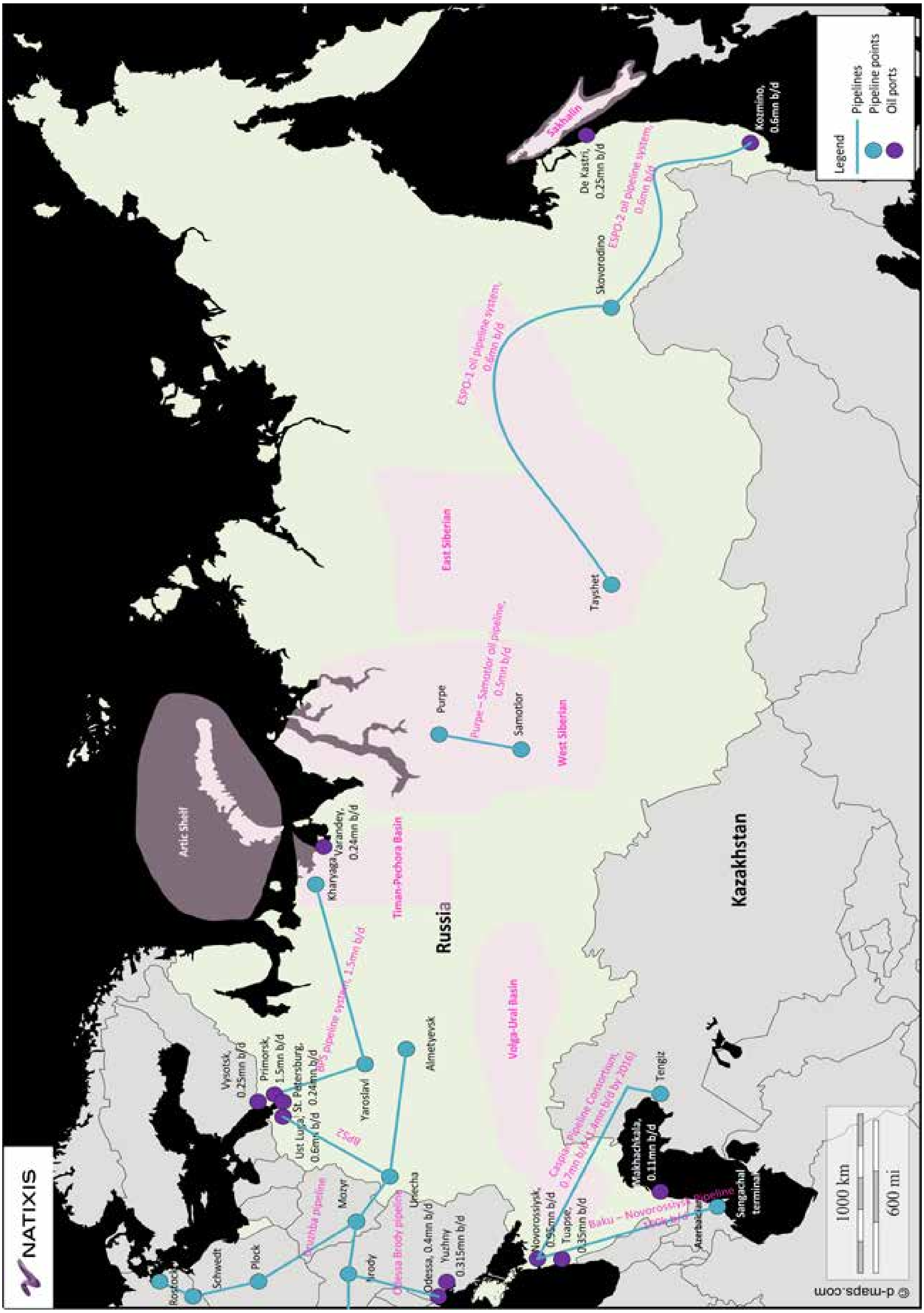
The government derives the majority of its energy income from three separate taxes and duties; mineral extraction tax (MET), export duty (crude and oil products sold abroad) and excise duty (oil products sold at home). While MET rates have been increased for existing fields, exemptions have been given for high viscosity oil as well as early production at new fields north of the arctic circle and on Russia's continental shelf. The tax incentives are as high as $21 per barrel in order to attract foreign investment and know-how. Among prospective shale oil fields, reductions in MET rates of between 20% and 100% are applicable dependent upon reservoir permeability and layer thickness. MET rates for ageing fields begin to decline above 80% depletion rates to encourage maximum extraction from existing fields.

These discounts on MET rates, in particular for new, unconventional oilfields, are intended to encourage investment in future crude production. In parallel, exemptions to crude export duties have been introduced for high viscosity fields as well as those in either the arctic or Russian continental shelf (including Caspian, Nenets, Yamal-Nenets and East Siberia).

The Russian government's efforts to raise revenue from MET while at the same time incentivising investment in new oil and gas fields are expected to continue. There is also substantial scope to increase government revenue from natural gas, although the recent deal with CNPC may be a retrograde step given that this deal was only completed after the government agreed to reduce MET rates for the underlying gas producers.

While US shale oil production is estimated to be over 3mn b/d, in Russia tight oil represents only 0.2% of total production, mainly because Russia has not fully developed shale oil technology and exploration. This production comes from the Bazhenov shale in west Siberia, Russia's biggest shale oil field. The EIA estimated risked shale oil in place at 1,243bn bbl, with 74.6bn bbl as the risked, technically recoverable shale oil resource. According to BP's 2014 Energy Outlook, Russian production from tight reserves is expected to grow to 1mn b/d by 2035. Despite the Ukrainian crisis, in May 2014 Total agreed a deal with Lukoil to develop

Main Russian Oil Pipelines and Ports



Sources: Natixis, D-maps

shale oil prospects in the Bazhenov area (western Siberia). Together they will set up a joint venture in which Total plans to invest between $120mn and $150mn in the first two years to explore and develop four licenses in a 2,700 square kilometers area in the Khanty-Mansy autonomous district. Seismic explorations are planned for 2014 and drilling in 2015. The Russian portion of Total's overall oil output is around 207,000b/d and Total plans to increase this to 400,000b/d by 2020.

2014 Oil Output Forecast

Ignoring the 2008-2009 period where the global financial crisis influenced national output, Russian crude oil production has increased each year since 1999. Meanwhile Russian majors are facing difficulties halting decline rates at mature west Siberian fields where 60% of the national output is produced. This has started to reflect in Russian crude and condensate production growth that appears to have reached a peak as oil output reached a post-Soviet monthly high of 10.59mn b/d in January 2014 according to ESAI. In 2014 Russian oil output is expected to either remain unchanged or increase marginally by 35,000b/d to measure 10.5mn b/d against 10.46mn b/d in 2013. The year-on-year output increase expected in 2014 is due to production gains that occurred in late 2013. In 2015, output is expected to fall by around 25,000b/d to 10.47mn b/d.

The biggest fear this year would come from the Ukrainian crisis, as foreign companies (mostly from western countries) accounted for roughly 10% of total Russian output. Further sanctions from USA and Europe could have a big impact on national oil output and investment in future projects.

Crude Exports

Russia has six main blends of oil. The Urals blend is Russia's main export grade and accounts for more than 80% of Russia's exports. Its quality can vary according its export point. On average Urals has a gravity of 31.3° and 1.25% sulphur content but its gravity can vary between 31° and 33° and its sulfur content between 0.8% and 1.8%.

Russian crude oil grades

Grade	API (°)	Sulphur (%)
Urals	31.3	1.25
Eastern Siberia-Pacific Ocean	35	0.50
Siberian Light	35.1	0.57
Sokol	36.7	0.24
Vityaz	41	0.18
Yuzhno Khylchuyu	33.7	0.76

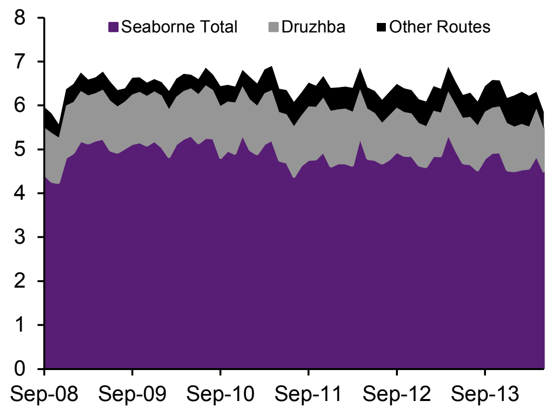
Sources: Natixis, IEA

Russia exported around 45% of its crude oil production in 2013, ie around 4.7mn b/d. The majority of this was exported to Europe (3.05mn b/d) although Asian exports increased to 750,000b/d. This gradual shift from European to Asian exports has been a strategic trend for some years now, but it is expected to accelerate in the immediate future. Russia plans to triple crude exports to China to 1mn b/d from 300,000b/d (2013) over the next decade.

In 2010, Rosneft began to ship 300,000b/d of crude to China, under a $25bn loan for oil deal. In June of last year, Rosneft and CNPC signed a deal to double oil flows to China to reach 600,000b/d ($270bn, over 25 years). On 1 January 2014, Rosneft started to send 140,000b/d of crude oil to CNPC via a pipeline from Kazakhstan to China under a 5-year agreement with an additional of 40,000b/d to CNPC through the ESPO pipeline.

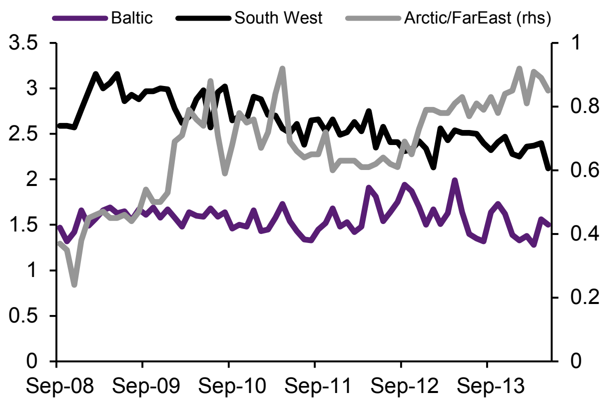
In October 2013, Rosneft signed an agreement with China's Sinopec to supply 200,000b/d of crude over 10 years for a value of $85bn.

Russian crude exports (mn b/d)



Sources: Natixis, IEA

Russian crude exports by sea (mn b/d)



Sources: Natixis, IEA

Last year, Rosneft also pledged to supply the planned Tianjin refinery which should probably start in 2020. The crude will be shipped by tanker from Kozmino port according to Rosneft. PetroVietnam has also signed a deal in May 2014 for Rosneft to supply the Dung Quat Oil Refinery with 6mn tonnes/yr (120,000b/d) from 2014 to 2039, via the Kozmino terminal, once the refinery has completed the final stage of its modernization.

Exports at Kozmino were expected to increase from 300,000b/d in 2010 to 600,000b/d in 2014, although volumes are currently believed to be around 440-460,000b/d so far this year, according to sources.

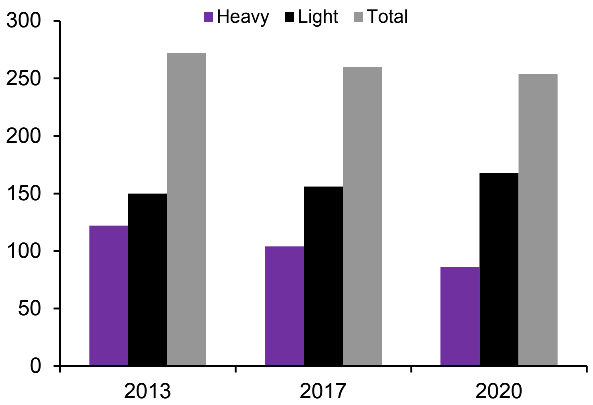
Refining Sector

The old Soviet Union left a huge refining system in Russia, the third largest in the world behind the US and China, with approximately 6.2mn b/d of total capacity. But much of this was constructed before the 1970s, with a focus on production of fuel oil rather than middle and light distillate products for transport needs.

Russia's refining sector is nevertheless changing rapidly. A combination of adjustments to export tax rates and excise duties on oil products represents a clear plan to modernise Russia's refining system with the aim of increasing output of cleaner, higher quality products. At the same time, it should allow the government to receive a higher proportion of revenue from both domestic sales and exports of oil products.

According to Rosneft, total Russian refinery throughput could fall to 4.7mn b/d from 5.5mn b/d currently as they cut down on high fuel oil producing refineries, but the share of output accounted for by light products should increase. Investment in new plant would then be expected to take refinery capacity up to around 6.8mn b/d by 2018, with this new refining capacity producing more light and middle distillate products.

Rosneft throughput forecast after upgrade (mn tonnes/yr)



Sources: Natixis, Rosneft

2014 Refining Outlook

According ESAI, Russian refiners processed 5.8mn b/d of crude (equal to 92% of total capacity) in the first three months of 2014, representing 360,000b/d yoy growth. In the second quarter, Russian refinery utilisation rates are believed to have dropped by 3% pts compared to the previous quarter according to the seasonal maintenance programme provided by the Energy Ministry earlier this year. A big part of this additional first quarter throughput has been generated by simple refineries (annual throughput: 821,000b/d, annual growth: 269,000b/d) with a large component of fuel oil output. As Russia plans to increase export taxes on fuel oil in 2015, we do not expect refinery processing volumes to carry on increasing since refining profits are being transferred from the bottom of the barrel to the middle, with older, less complex refineries potentially making a loss.

2011 changes to Russian export taxes

Product	Previous export tax rate (% of crude export tax rate)	Export tax rate (% of crude export tax rate)
Diesel and jet	67%	66%
Fuel oil	46.70%	66%
Gasoline	90% (from May11)	90%

Sources: Natixis, Ernst and Young

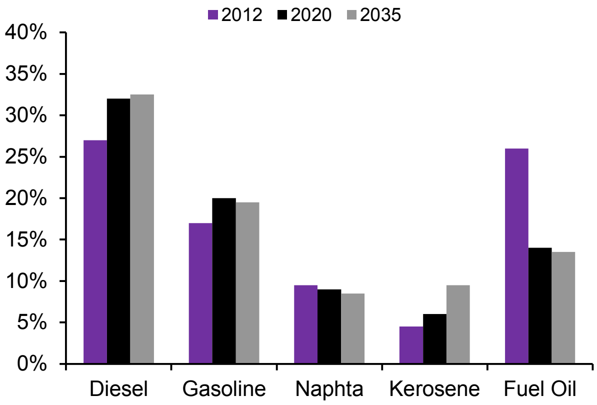
Planned changes to Russian export taxes

Product	2014	2015	2016
Crude oil	59%	57%	55%
Fuel Oil (%of crude oil)	66%	66% or 100%	100%
Diesel (% of crude oil)	65%	63%	61%

Sources: Natixis, Ernst and Young

In this case these refineries are likely to reduce their processing rates considerably, resulting in Russian refinery processing volumes falling to 5.5mn b/d or even lower after 2015 unless investments are made to modernise these refineries or Russia decides to postpone the hike in fuel oil export tax. According to IEA, a total of 885,000b/d of upgrading capacity and 420,000b/d of CDU capacity investment will come on-stream in the FSU countries over the 2013-19 period, alongside 385,000b/d of desulphurisation capacity. According to ESAI, the upgrading units will be mostly in the form of hydrocracking capacity which is expected to rise by more than 700,000b/d between 2013 and 2020 in Russia, generating increased yields of high value products. The ratio of hydrocracking and catalytic cracking capacity to crude distillation will be expanded to 25% from around 10%.

Main oil product yields in Russian refineries with the new policies scenario



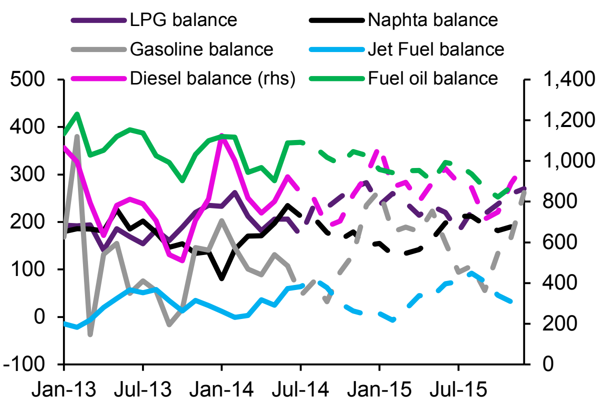
Sources: Natixis, IEA

Russian Oil Product Exports

In the short term, fuel oil exports should decrease as the changes to Russian export taxes act as a disincentive for Russian refiners to export fuel oil. Instead we would expect to see an increase in crude oil exports, especially to Asian countries, as Russia is gradually increasing its eastbound exports.

In the medium term (2020), the upgrade to Russia's refining system is expected to have a major impact on international oil product markets. According to IEA, Russian exports of mid-distillates will increase from 0.9mn b/d in 2013 to almost 1.2mn b/d in 2019 vs a decline in fuel oil exports from 1.3mn b/d in 2013 to just over 0.6mn b/d in 2019. In combination with the gradual shift in crude exports from Europe to Asia, the increase in oil product exports is expected to add further downward pressure to Europe's already compressed refinery margins. Also changes to the export tax system might further help the profitability of upgraded Russian refineries in the long term.

FSU oil products supply-demand balance (000b/d)



Sources: Natixis, ESAI

Notes: dotted points are forecasts, supply/demand balance is supply minus demand

Oil and Oil Product Taxes

On 30 September 2013, Vladimir Putin signed Law No. 263-FZ, changing the current rates of export duty and establishing the future base rates of mineral extraction tax on crude oil. The new rates came into force on 1 January 2014. The law establishes the rates of MET per tonne of oil produced as seen in the table.

Mineral extraction tax

Year	MET tax / metric tonne (RUB)
2013	470
2014	493
2015	530
2016	559

Source: Natixis

In response to a shortage of gasoline in the spring of 2011, Russian authorities increased the gasoline export tax to 90% of the crude tax rate (as well as reviewing excise rates on oil products). The fuel oil export tax was brought up to the same level as diesel and jet fuel, with the aim of incentivising the oil industry to invest in the secondary refining process.

After the subsequent backlash from the oil industry at the sharp hike in oil product export taxes, Russian authorities reduced the underlying export tax on crude oil in October 2011, which was cut to 60% from 65%. In 2014, this base tax rate on crude exports was further reduced to 59%, and it will decline progressively to 55% by 2016. There are further incentives given to oil producers investing in hard-to-recover oil plays (as discussed earlier).

As the export tax on diesel is gradually cut to 61% of the crude export rate, the incentive for refiners to crack fuel oil

into lighter products is expected to increase, particularly as the tax on fuel oil will be increased towards 100% of the crude export levy from 1 January 2015. This will largely affect simple refineries that produce approximately equivalent volumes of fuel oil and diesel. Until now these refineries were exporting this fuel oil to markets with more complex refineries such as the US.

There is still uncertainty over the convergence of tax rates between fuel oil and crude oil should the modernisation of refineries run behind schedule. Export duty on gasoline remains unchanged at 90% of the crude export levy.

Among excise duties (charged on local sales of oil products), Russian authorities have progressively increased the rates applicable to lower value and higher polluting fuels, while rates on the cleaner class-5 gasoline have increased more slowly. These higher excise duties are helping to push domestic Russian fuel prices up towards international prices, in the process allowing the government to take a larger share of domestic oil revenue. The shift in excise duties favouring production of cleaner fuels is also encouraging refiners to upgrade older refineries to produce a higher volume of cleaner fuels.

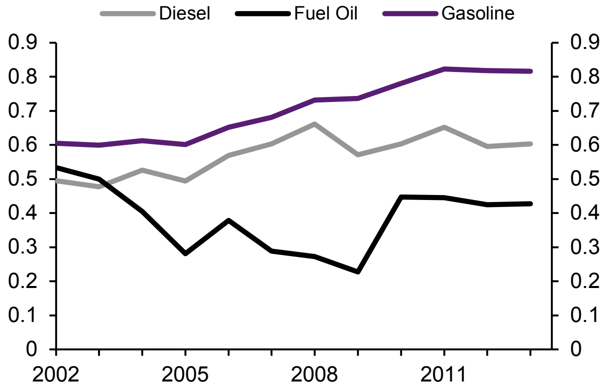
Oil Demand

Among the BRICS economies, Russia is the least energy efficient, requiring 0.4 tonnes of oil-equivalent energy to generate each $1,000 of GDP (based on 2013 data from Datastream and BP). This compares vs 0.38 tonnes of oil-equivalent energy per $1,000 of GDP in China, 0.31-0.33 tonnes per $1,000 of GDP for South Africa and India and just 0.125 tonnes per $1,000 of GDP in Brazil.

This heavy energy intensity is in large part a legacy of the old soviet system, where government policy skewed resources towards certain sectors such as heavy industries and defence which consume energy more intensively than other sectors of the economy. Thanks to Russia's rich endowment of natural resources, there remains little incentive to change this policy mix.

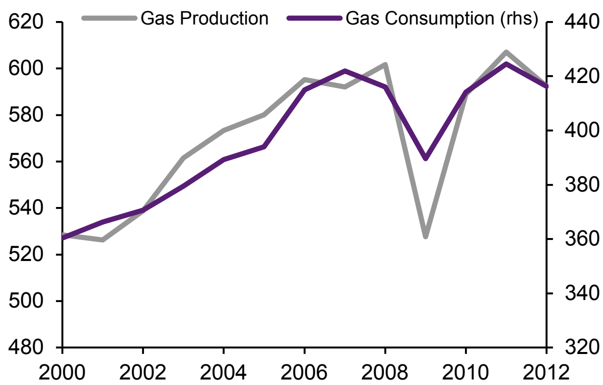
During the decade between the Russian financial crisis (1998-09) and the global financial crisis (2008-09), the Russian economy grew rapidly, expanding at an average annual growth rate of 7.5%. Despite this rapid economic growth, Russian consumption of oil grew very slowly, rising by just 0.9% per annum over the same period, according to BP data. During this period, economic growth in less energy-intensive sectors of the economy helped to bring down Russia's energy intensity of output significantly. The decline in the Russian population between the soviet breakdown until 2008 also contributed to the lower demand for oil products.

Oil products demand (mn b/d)



Sources: Natixis, JODI

Annual natural gas production and demand (bcm)



Sources: Natixis, BP

With Russia's industrial complex in decline, fuel oil consumption has declined since 1999. Fuel oil was also being replaced by other fuels, especially in the power sector, which also contributed to the slower growth in total oil products demand.

Since the low point in 2009, Russian demand for oil has expanded by more than 3% per annum, even as economic growth has slipped back to an average of little more than 3% per annum since the beginning of 2010. Russia's car fleet has been increasing over this period, encouraged by the increase in Russia's population since 2008, resulting in higher demand for gasoline. Russia's refinery upgrade process and a concomitant increase in refining capacity may also play a role in the increase in energy consumption.

2014 Demand Outlook

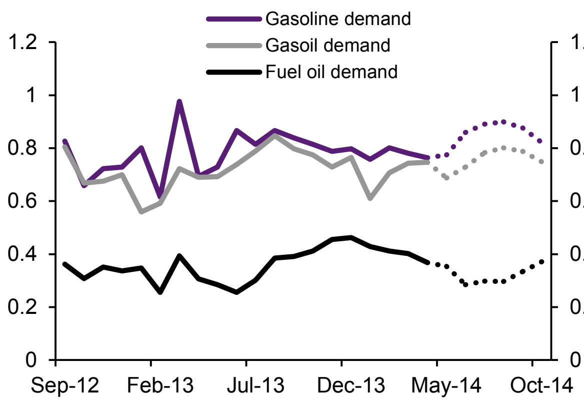
ESAI forecasts that Russian demand for gasoline and gasoil will increase only slightly in 2014, rising by 17,000b/d and 11,000b/d to 0.817mn b/d and 0.735mn b/d respectively in

2014 compared to 2013. Fuel oil demand will increase in 2014 to 395,000b/d from 354,000b/d last year. In 2013, Russian demand for gasoline, gasoil and fuel oil increased by 3.1% yoy, 1.3% yoy and 5.7% yoy respectively.

Of Russia's 735,000b/d of gasoil consumption, 64% is attributed to road transport (mostly freight), according to estimates by Russian railways. Another 8% is rail and most of the remaining 28% is agriculture.

Following the Crimea annexation, forecasts for Russian growth have generally been revised downwards. IEA revised its 2014 Russian oil demand forecast to 3.48mn b/d in April 2014 and 3.47mn b/d in May 2014 respectively against 3.51mn b/d in February 2014. However, this remains higher than last year (3.42mn b/d) and 2012 (3.3mn b/d). The 2014 number assumes a low risk scenario with a "limited and short lived impact of the Crimea crisis." In a high risk scenario, with a more severe shock to the economy and investment activity and further economic sanctions from western countries, Russian oil demand could decrease to 3.3mn b/d.

Oil products demand forecasts (mn b/d)



Sources: Natixis, ESAI

Notes: dotted points are forecasts

Impact of tensions between Russia and Ukraine?

To what extent could tensions between Russia and Ukraine affect Russian crude output and the supply of oil to Europe? In the aftermath of the Malaysian Airline MH-17 crash, the US imposed tighter sanctions on Russia in an effort to facilitate a negotiated peace settlement between Ukraine and Russian separatists. In July, the US Treasury imposed restrictions on the provision of financing to two major Russian banks and two of Russia's largest energy companies, Novatek and Rosneft. In early-August, the US Department of Commerce imposed significant new restrictions on exports, re-exports, and in-country transfers of goods, software, technology, and data for use in Russia's oil and gas sector related to deepwater, Arctic offshore and shale exploration and production. The European Union followed the US in prohibiting financing for state-owned Russian financial institutions, as well as the supply, transfer or export of goods and technologies destined for Russian deep water, Arctic and shale oil exploration and production.

Tighter economic sanctions could potentially impact Russia's upstream industry, delaying the growth in oil output from unconventional resources deemed essential to sustain Russian government revenues in the future. On the downstream side, the impact of sanctions is likely to be more limited unless sanctions are imposed on components required for the upgrading of Russian refineries or indeed upon the overseas sale of Russian oil products.

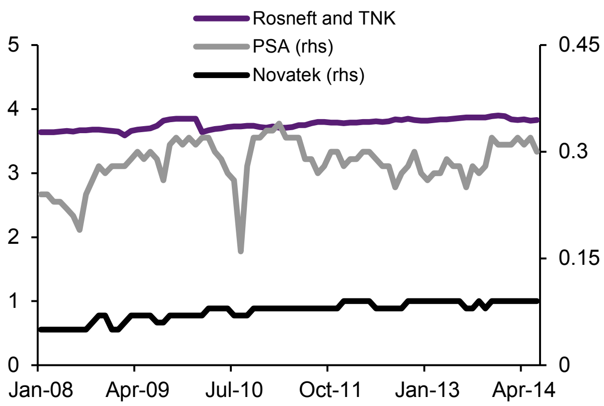
Ukraine itself is very dependent on Russian oil. In 2013, Ukraine produced an average of 65,000b/d of crude oil and petroleum liquids and consumed 280,000b/d. Most of this consumption was met by petroleum product exports from Russia, estimated at around 190,000b/d. Ukraine is also a major transit country for Russian crude exports to eastern and central European countries (90,000b/d of crude oil and products via ports in 2013 as well as 310,000b/d via the Southern Druzhba pipeline). According to the IEA, Slovakia, Hungary and Czech Republic imported 100%, 94% and 65% of their crude imports respectively through the Southern Druzhba pipeline in 2013. Even if this pipeline could be substituted easily with other Russian export facilities (Baltic Sea ports, Northern Druzhba pipeline), the impact of even a temporary shutdown in the Ukrainian oil and gas infrastructure would clearly be felt across eastern and central European countries.

With 30.8bn boe of liquids reserves, Rosneft holds 38.5% of proven Russian reserves. Rosneft produced 4.2mn b/d of crude oil in 2013, representing 40% of Russian crude oil production. This makes Rosneft the world's largest publicly traded oil company by output and reserves. Through its 19.75% equity ownership in Rosneft, BP has the largest Russian exposure among western energy companies. The other significant stake held by western companies is Total's 16.96% stake in Novatek. Other than this, most foreign investments in Russian oil production and development are concentrated in joint venture production sharing agreements (PSA).

The PSAs produced an average of 280,000b/d in 2013. Exxon and Shell (Sakhalin I and Sakhalin II projects) and Total and Statoil (Kharyaga project) are the main western participants in PSAs in Russia.

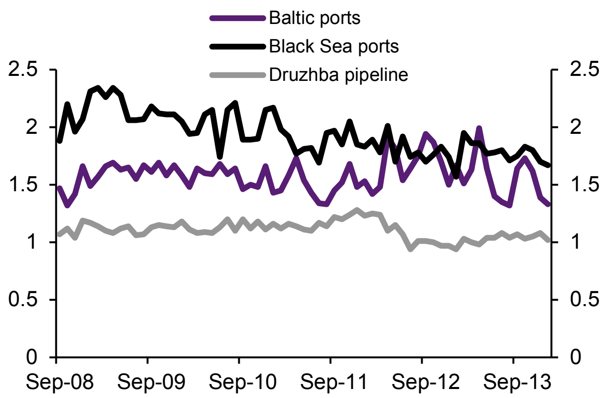
While we do not expect Russian oil producers to withdraw supplies from Europe, these PSAs and cross-shareholdings clearly illustrate the potential damage that tit-for-tat sanctions could have upon European oil supplies.

Foreign companies crude oil output in Russia (mn b/d)



Sources: Natixis , CDU TEK, Bloomberg

Crude oil exports through Europe (mn b/d)



Sources: Natixis, IEA

On 21 May, Russia's Gazprom and China's CNPC signed a long-awaited natural gas deal. Under negotiation for over 10 years, the 30-year natural gas contract will deliver 38bcm/yr natural gas exports to China via a new eastern corridor. Immediately after the signature of the deal, discussions on the construction of an additional western pipeline will commence, which would will run from western Siberia to China with a capacity of a further 30bcm/yr. While phase 1 gas supplies will come from new eastern Siberian fields, the second phase would, if implemented, take gas that might otherwise have been available to European markets. Gas deliveries under the first stage of the agreement are expected to commence within the next 4 to 6 years.

The signature of this $400bn deal marked a major step towards redirecting Russian energy exports away from declining markets in Europe and towards growing markets in Asia. The price of the deal is clearly lower than Gazprom had intended. At a little over $350/1000m^3, this might not have been profitable were it not for the reduced MET rate offered by the government to the projects which will supply gas to the new pipeline.

What is clear from the Gazprom-CNPC natural gas deal is that the effects of the current tensions in Ukraine are more likely to be felt over the long term than over the short term. While an escalation of tensions in Ukraine has the potential to lead to negative short term economic effects, it is clear that the long-term effects will be an acceleration of the shift in Russia's economy away from Europe and towards China and the rest of Asia. In this respect, Russia is turning away from its post-1980 opening up to Europe, and moving towards a more Asian-focused economic model.

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Europe

Europe's economic situation remains difficult. Many of the continent's major structural problems are still unresolved, and the growing geopolitical tensions in MENA and Ukraine are damaging export markets, to the detriment of Germany's export-oriented economy in particular.

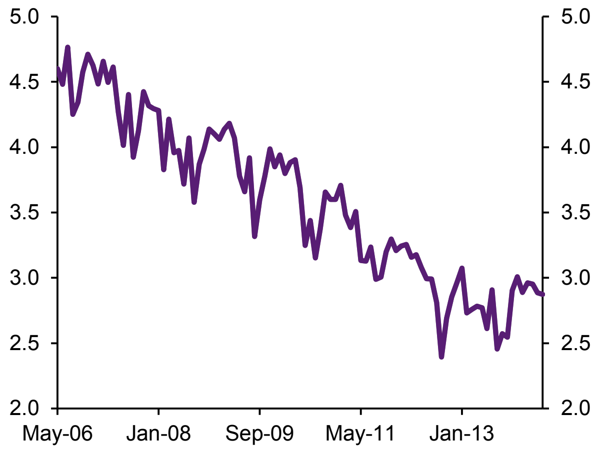
Against this bleak backdrop, European refineries continue to face huge economic challenges. While European demand for gasoil is supported by Europe's growing dependency on diesel-powered motor vehicles, this creates a natural overcapacity among other oil products, in particular gasoline. The cheapness of US crude versus Europe's Brent benchmark has in effect removed the primary export market for Europe's surplus gasoline which had previously underpinned European refiners' profitability. Worse still, growing competition from new and upgraded refineries in MENA and Russia threatens to eat into refiners' profits from mid-distillate products. To make a bad situation worse, an imminent tightening of MARPOL and SECA rules on bunker fuel will require substantial investment from European refineries to meet the new low-sulphur requirements.

Introduction

In 2013, the United Kindom Continental Shelf (UKCS) and Norwegian Continental Shelf (NCS) contained 3bn bbl and 8.7bn bbl respectively in proven oil reserves, according to the BP statistical review (2014). Both continental shelves share many characteristics (eg location, maturity) but face different challenges. While energy companies operating on the UK continental shelf have struggled to find significant discoveries and have seen exploration activity decline since 2008, the Norwegian continental shelf has witnessed an improvement in its exploration activity as is evident from the rapid increase in exploration wells since 2000, and have subsequently discovered many oil fields, including the Johan Sverdup, one of the five largest oil discoveries ever made in the NCS, and the biggest since 1979.

In 2013, total OECD Europe crude oil production declined by 7% yoy. In contrast, for the first five months of 2014, crude oil production increased by 3.1% yoy, mainly driven by an increase in Norwegian oil output. In this section we discuss developments in two of the largest European continental shelves.

OECD Europe - crude oil production (mn b/d)



Sources: Natixis, JODI

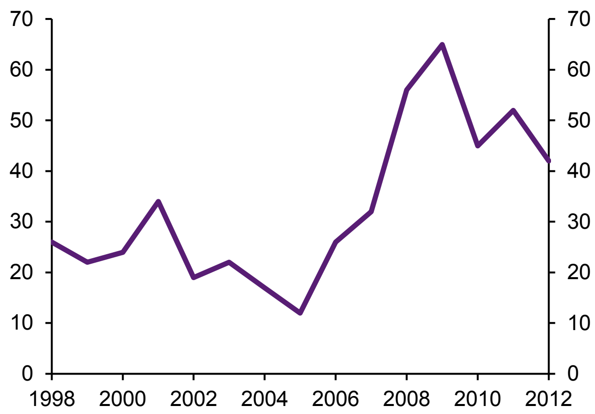
Norway

Before 2000, the Norwegian continental shelf was mainly exploited by large Norwegian companies. While there were typically between 20 to 50 exploration wells drilled per year during the nineties, a decline set in at the end of the decade, resulting in a fall to just 12 exploration wells drilled in 2005 (the lowest level).

Since 1999 the Norwegian government has initiated changes to boost exploration activity, initially awarding licences in mature areas ("Annual North Sea Awards," 1999) and subsequently adding licences in the Norwegian and Barents Sea ("Awards in predefined areas," 2003). In 2004 the government also introduced the exploration tax refund, under which up to 78% of exploration costs are refunded in the year after they are incurred. These measures have helped to bring new companies into the Norwegian continental shelf.

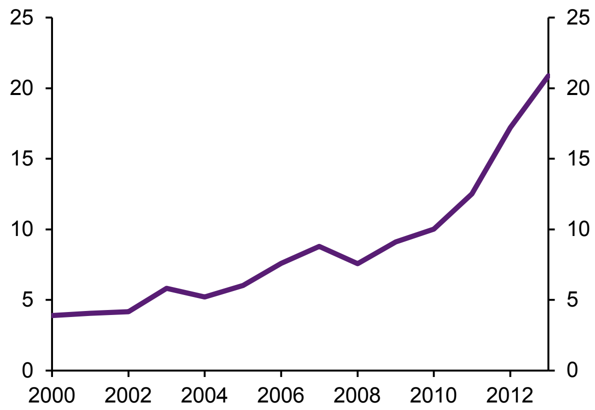
On 15 March 2013, large companies held 31% of the production licences compared with 53% in 1998, with European gas and power companies having increased their stake from almost zero to 15.5%. This has resulted in a more diversified industry mix. Since the 2005 low, the number of exploration wells has increased steadily, peaking at 65 in 2008 but remaining at more than 40 since then.

Exploration wells on the NCS



Sources: Natixis, Norwegian Petroleum Directorate (NPD)

Norway unit operating cost ($/bbl)

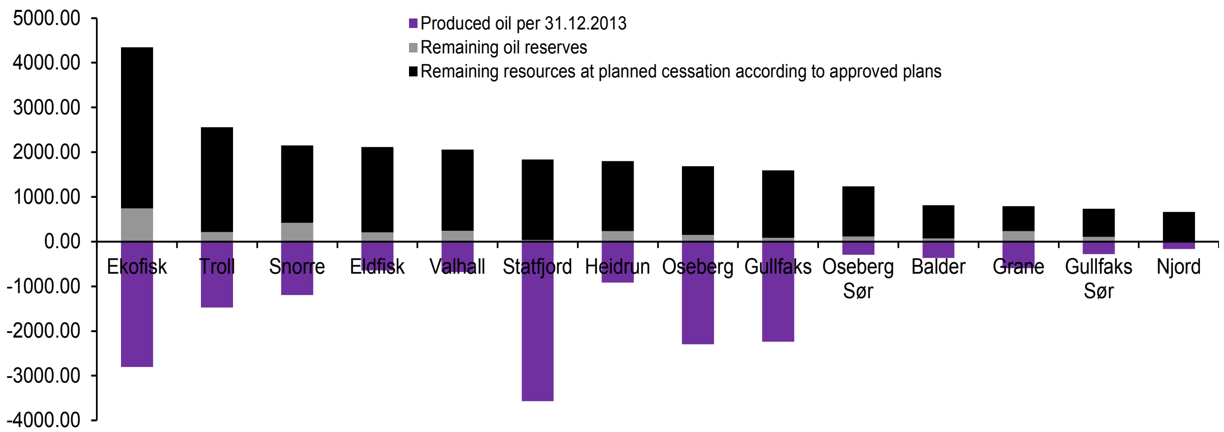


Sources : NPD, Natixis, 1US$ = 6.16NOK

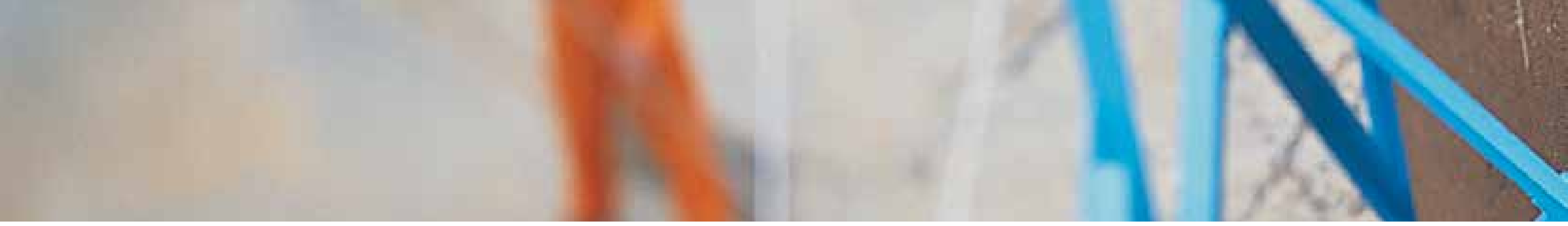
During the last five past years several large fields have been discovered, including the Johan Sverdrup on the Utsira High which is the largest discovery on the NCS since 1979. With a recoverable resource between 1.8bn boe and 2.9bn boe, Johan Sverdrup production could start in 2019 with initial output at 350,000b/d, rising thereafter to a peak of 550,000-650,000b/d.

Two new discoveries, Skrugard and Havis in 2011 and 2012 (now both called Johan Castberg oil fields) represent the first discoveries in the Barents Sea over the past decade. According Statoil in 2013, the fields together contain approximately 400mn to 600mn boe. These two fields have helped to rekindle interest in exploration in the Barents Sea. The Skavl prospect has made the Castberg area oil field development project more robust with the discovery of 20-50mn bbl of recoverable oil in December last year. Exploration is continuing in 2014 and its results should be indicative regarding the potential of this area.

Norway resources overview (mn bbl)

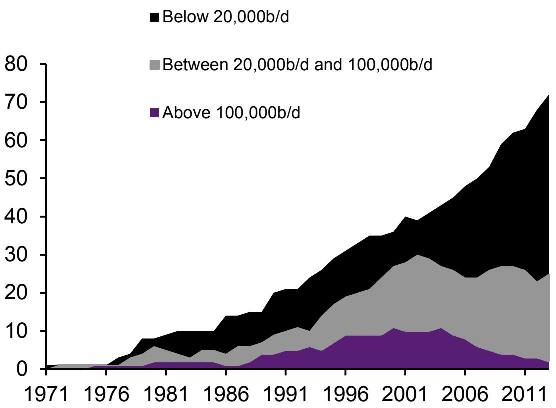


Sources: Natixis, NPD



The Johan Sverdrup and the Johan Castberg fields are crucial to Norway's oil output growth as they are expected to account for more than a quarter of Norwegian oil production once they come on-stream according the Norwegian Petroleum Directorate, while the rest of the new output will come from small fields. Johan Sverdrup and Johan Castberg fields will require their own infrastructure and the impact on the cost of production will not be negligible. The Johan Sverdrup (for a reserve between 1.8 and 2.9bn boe) could cost up to $20bn to develop and the Johan Castberg field $15.5bn for 0.6bn boe. Johan Sverdrup and Johan Castberg are both expected to start-up in 2018.

Number of fields with oil production

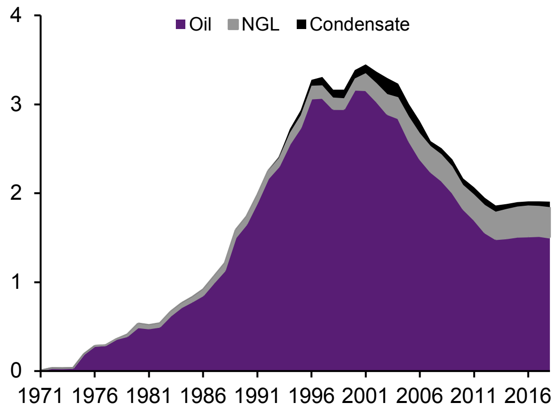


Sources: Natixis, NPD

In May 2013, the Norwegian government proposed changes to the petroleum tax system, with a 51% special petroleum tax starting in 2014 (up from 50%). Oil companies would still be able to deduct most of their investment costs, but slightly less than before. With immediate effect, the uplift (a tax deduction against the special tax of 50%, given over 4 years from investment year) will be reduced from 30% to 22%. The industry expected new rules on the uplift to come soon as some tax advantage were considered as "over compensation". The surprise came when the government did not take into account any public or industry point of view to take this decision. As a result some ambitious projects have been delayed with fears about their profitability eg Statoil's development of the Johan Castberg field last year. This new tax rule could have a negative impact on Norwegian oil production over the coming years.

The Norwegian Petroleum Directorate (NPD) believes that Norwegian production will remain at around current levels, supported by the major discoveries, Johan Sverdrup and Johan Castberg, both expected to come on-stream in the next five years. It is important to note that this forecast takes into account cost levels in the autumn of 2013; a rise in these costs could have negative implications for future output. The Johan Castberg field is particularly sensitive in this respect, since Statoil has already delayed some investment on this field due to uncertainty surrounding the estimation of resources and the less generous tax system. In a recent comment by Statoil's Vice President for development and production, Arne Sigve Nylund, suggested that Statoil needed more time to develop the Johan Castberg project. Although the 2013-2014 exploration campaign helped make a second oil discovery in the Barent's sea, it was below Statoil's volume expectations required to make the Castberg field viable for supporting infrastructure.

Norway oil production forecast (till 2018, mn b/d)



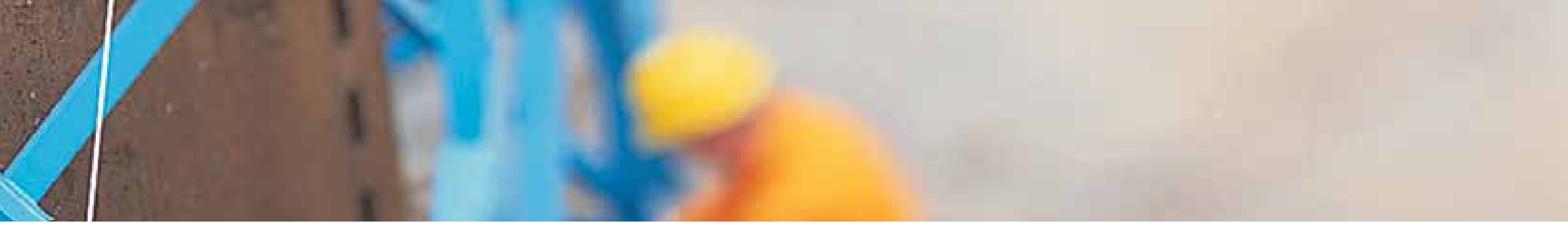
Sources: Natixis, NPD

NPD, IEA and OPEC's expectations for Norwegian crude output are given in the table below. In the year to May, Norwegian oil output increased by 4.5% yoy. We expect Norway's crude oil output to average 1.9mn b/d in 2014 and 1.93mn b/d in 2015, rising by around 4% yoy in 2014 and then at least 2% yoy in 2015. In 2013, Norway produced 1.84mn b/d (-4.4% yoy), according to BP. A number of projects are helping to boost Norway's oil output. Ivar Aasen, Gudrun, Valemon, Gina Krog and Aasta Hansteen fields should further support Norway's oil production from 2016 or 2017 onwards. In addition to that, loadings at Ekofisk have also increased by 51.5% in the first half of 2014.

Norway oil production (mn b/d)

	2013	2014	2015
IEA	1.84	1.83	1.83
OPEC	1.84	1.84	1.88
NPD	1.77	1.8	1.83

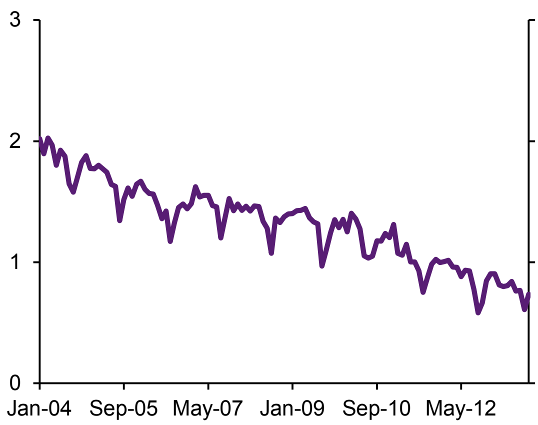
Sources:Natixis, IEA, OPEC, NPD



UK

The oil and gas industry is of great importance to the UK economy as it satisfies 67% and 53% of UK oil and gas demand (2012). The industry paid £5bn in production taxes in the 2013/2014 fiscal year, but this number is down from £6.5bn in the previous year as production has declined steadily from 2010 to 2013, down by 38% to 1.43mn boe/d. Because a significant share of activity takes place in Scotland, the industry also plays a major part in the debate about Scottish independence. The referendum taking place in September this year could therefore have a substantial impact on the future of the UK's oil and gas industry. According to research by Aberdeen University's Professor Kemp, the Scottish share of total oil production in the UKCS was more than 95% while for gas it was 58% in 2010. The Scottish share of total hydrocarbon production (including NGLs) was 80%. Hence if Scotland were to become independent, the UK continental shelf (UKCS) would be expected to be divided on a geographical basis. If a median line were drawn such that all points on the border were the same distance from the Scottish and UK coastline, around 90% of the UK's oil resources would belong to the Scottish jurisdiction.

UK crude oil production (mn b/d)



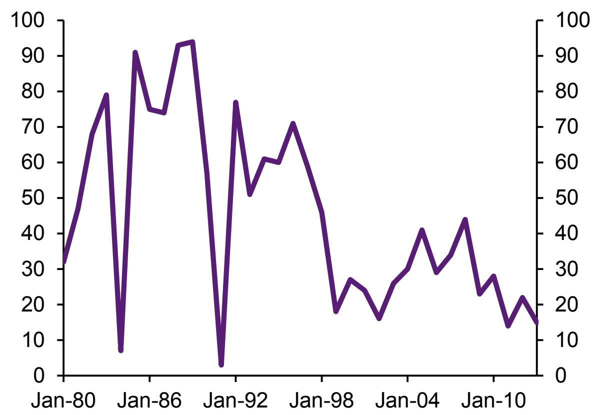
Sources: Natixis, Bloomberg

The Sir Ian Wood's report, published on 24 February 2014, pointed out a number of problems facing the UKCS and gave some recommendations to improve the industry model.

Wood Report: Production Efficiency and Costs

The report mentioned production efficiency, falling to 60% from 80% a decade ago, as one of the biggest factors in the decline in oil production over the last few years, making this one of the main problems to correct. Sir Ian Wood recommended setting up a new regulator to oversee the industry and to ensure that resources were exploited to their full. The regulator could also help on the exploration side, promoting UKCS fields and facilitating timely and effective data sharing.

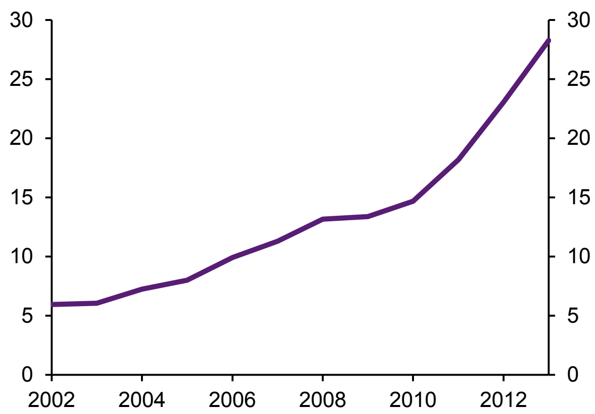
Number of offshore wells drilled



Sources: Natixis, Bloomberg

UK unit production costs have risen over the past few years due to a decline in oil production and an increase of the costs of extraction. On top of this, the low production efficiency level (around 60%) is pushing unit operating costs higher than those in Norway.

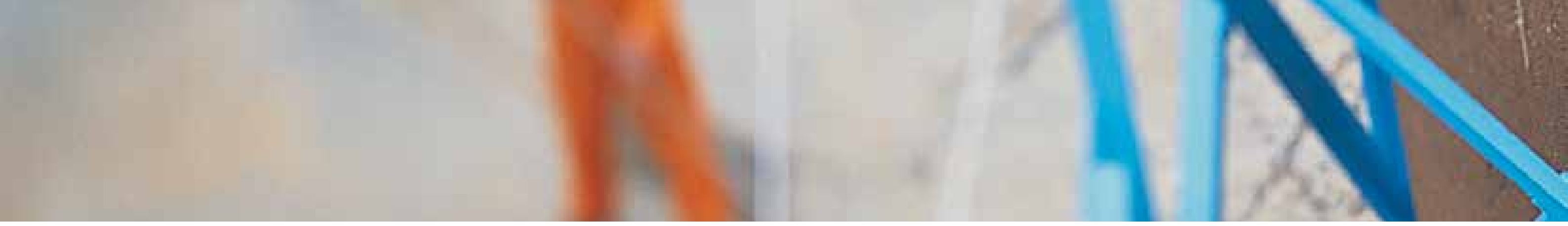
UK operating cost per unit ($/bbl)



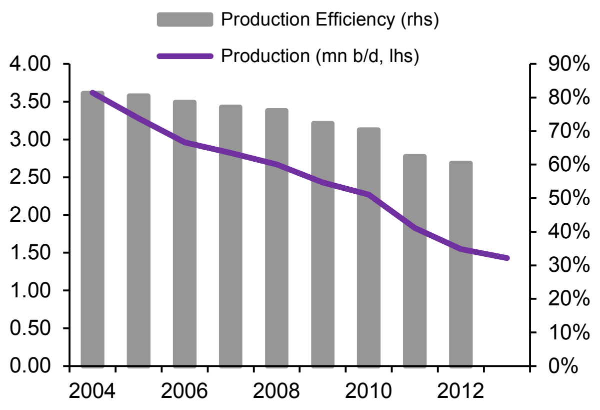
Sources: Natixis, Oil and Gas UK, Natixis, 1US$ = 0.5989£

Wood Report: Brownfield Allowances and Decommissioning

The UK Treasury has an important role to play in terms of the tax environment, eg its Brownfield Allowances (September 2012). A significant number of Sir Ian's interviewees suggested that the government should consider further extension of field allowances to promote new technologies, increase recovery, and encourage major refurbishment of existing fields with the effect of extending field life and postponing decommissioning.



Production efficiency

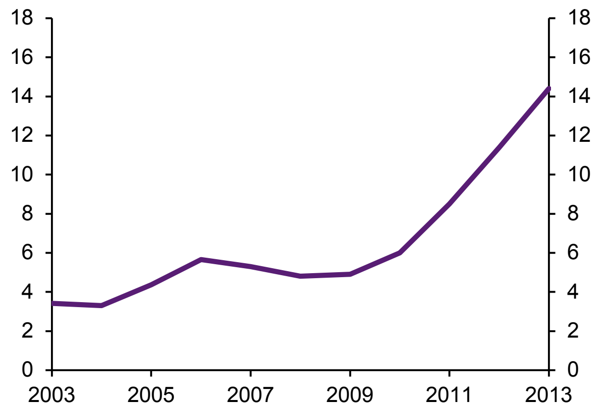


Sources: Natixis, Oil and Gas UK

Such measures may not be enough to stimulate exploration, although the recent discovery of the Johan Sverdrup field on the NCS, close to the border with the UKCS, could encourage exploration in the border area of the UKCS.

According to PILOT (formerly the UK oil & gas task force) estimation, between 0.5bn and 2bn boe are at risk from early decommissioning of existing infrastructure. The 2014 UK Oil and Gas activity survey suggested that decommissioning expenditure out to 2040 is expected to be £40.6bn (£37bn with existing installations and £3.6bn with new fields yet to be installed).

Capex investment on the UKCS (bn £)



Sources: Natixis, Oil and Gas UK

Wood report states that a further 12bn to 24bn boe could be produced in the next 20 years resulting in a £200bn boost to the British economy. Through PILOT, the industry and the government have already taken the initiative with the establishment of a Production Efficiency Task Force. The target is to return to an 80% production efficiency by 2016. The report welcomed work done by PILOT but pointed out the need to improve collaboration between different actors on exploration, infrastructure and decommissioning and to establish a regulator to facilitate and encourage collaboration on exploration, cluster field development and use of infrastructure.

In 2012, the U.K. government introduced tax incentives for investment in existing North Sea fields. This was followed, in 2013, with clarified tax-relief measures for the cost of dismantling old platforms in the North Sea. Since then, there has been a net increase in investment in the UKCS. Industry estimates suggest that field allowances introduced by the UK Treasury unlocked £7bn of new investment in 2013. A quarter of all these capital investments came from Conoco's Jasmine field development in the central North Sea and Shell's Schiehallion, BP's Clair Ridge, and Total's Laggan-Tormore projects in waters off the west of the Shetland Islands. These moves were also aimed at helping big companies sell more mature assets to smaller companies for further development. However, despite this increase, industry fears that investment will halve in the second half of the decade if there is not any further reform of the tax regime, due to high tax rates for some fields and a lack of incentives for long-term investment.

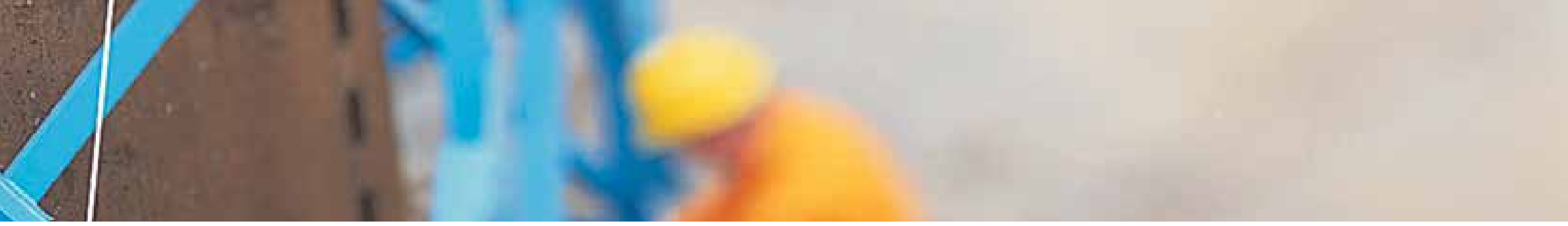
Investment in the UKCS (bn £)

	2011	2012	2013	2014
Total	16.7	21.3	25.8	25
Capex	8.5	11.4	14.4	13
Opex	7	7.7	8.9	9.6
Exploration & Appraisal	1.2	1.7	1.6	1.4
Decomissioning		0.5	0.9	1

Sources: Natixis, Oil and Gas UK

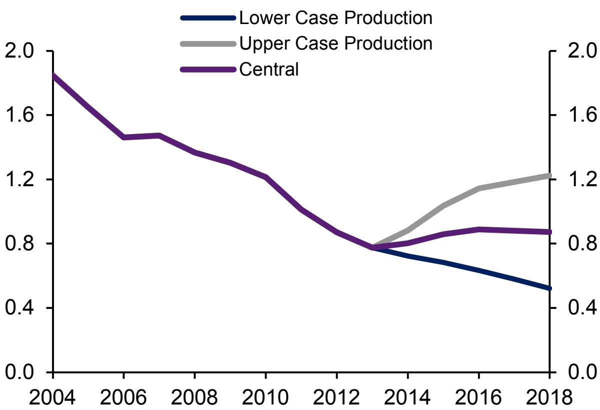
Crude Production Forecasts

We see three potential scenarios until 2018. In our lower case scenario we assume that the industry could reach only 70% production efficiency, while in the upper case scenario we assume that the industry achieves the government's 80% target. In the lower case scenario, we assume that oil production continues to decline at a rate equal to the worst seen during the last 10 years (-11%). In the upper case scenario, we assume that production will increase at a rate equal to the best seen during the last ten years (+3.4%). According to IEA, oil output is expected to bottom out at 725,000b/d in 2014 and then rebound marginally between 2015 and 2017 with an average growth of 40,000b/d until 2018. In the first five months of 2014, UK's oil output was up 2.4% yoy. This was due to some new field start-ups offsetting declining production and currently producing fields undergoing redevelopment efforts. The increases in production through 2018 will come mainly from supplies originating in the west of Shetlands offshore area, which are



expected to add about 200,000b/d of additional production capacity. Total is overseeing the development of the Laggan and Tormore condensate and gas fields and BP is redeveloping Magnus, Claire Ridge and Schiehallion fields.

UK oil production forecast (mn b/d)



Sources: Natixis, Bloomberg

Forecasts from other agencies for UK crude output have been given in the table below. UK's oil output in 2013 averaged 0.866mn b/d (-8.6% yoy), according to BP's latest statistical report.

UK oil production (mn b/d)

	2013	2014	2015
IEA	0.89	0.88	0.91
OPEC	0.87	0.89	0.89

Sources: IEA, OPEC

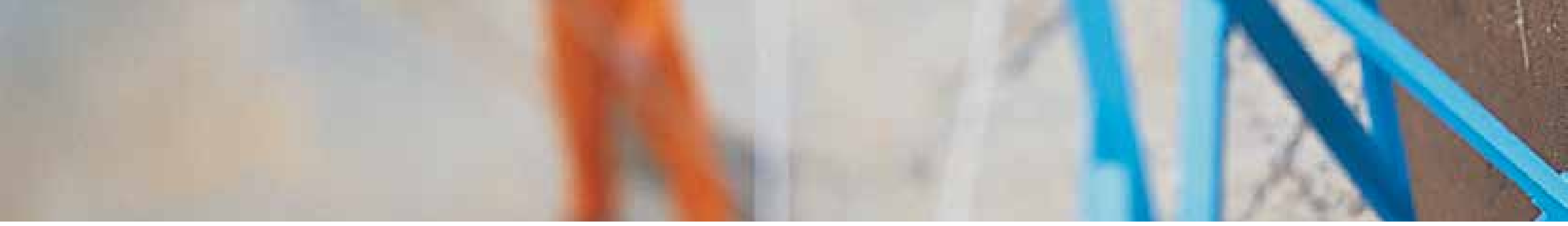
European Refineries

15 EU refineries have been closed down since 2009, cutting EU refining capacity by 8% (from 15.9mn b/d to 14.7mn b/d). While the IEA believes that between 1.5 and 3.5mn b/d of refinery capacity are at risk in the EU between 2012 and 2020, OPEC estimates suggest that roughly 750,000b/d distillation capacity was scheduled for closure or for on-sale as of mid-2013 and 2.5mn b/d is expected to be closed between 2013

European refinery closures since 2009

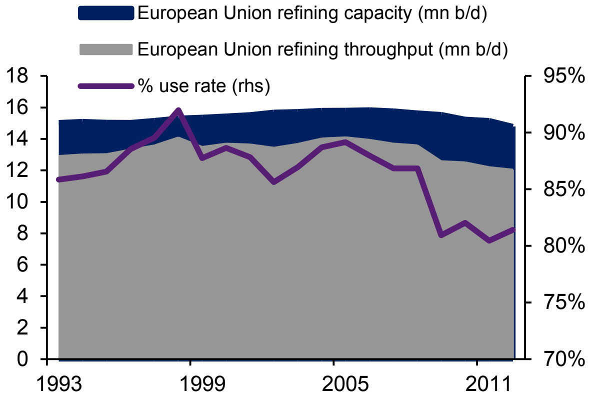
Country	Refinery	Owner	Capacity ('000 b/d)	Status	Period
2014					
Italy	Mantova	MOL	55	Permanent closure	January 2014
2013					
Italy	Falconara	API	83	6 month closure	January - June 2013
Germany	Harburg	Shell	110	Permanent closure	April 2013
Italy	Porto Marghera	Eni	80	Permanent closure	Q3 2013
2012					
France	Berre l'Etang	LyondellBasell	105	Mothballed	January 2012
Romania	Arpechim	Petrom	70	Permanent closure	January 2012
Ukraine	Lisichansk	Rosneft	160	Indefinite closure	March 2012
Czech Republic	Paramo	Unipetrol	20	Permanent closure	May 2012
Italy	Gela	Eni	105	10 month closure	June 12- April 13
UK	Coryton	Petroplus	220	Permanent closure	July 2012
Italy	Rome	TotalErg	86	Permanent closure	September 2012
France	Petite Couronne	Petroplus	162	Permanent closure	December 2012
2011					
Italy	Cremona	Tamoil	90	Permanent closure	October 2011
2010					
France	Reichstett	Petroplus	85	Permanent closure	November 2010
2009					
UK	Teeside	Petroplus	117	Permanent closure	May 2009
France	Dunkirk	Total	140	Permanent closure	September 2009
Germany	Wilhelmshaven	Hestya Energy	260	Permanent closure	October 2009

Sources: Natixis, Platts



and 2018. According to our estimates, around 560,000b/d capacity was shut down temporarily or permanently in 2013.

European refinery utilisation



Sources: Natixis, BP

EU is facing intense pressure from the increasing refining capacity outside of the continent. Middle East oil producers are opening new refineries, eg Jubail in Saudi Arabia (0.4mn b/d). According to OPEC, Middle East refining capacity should increase by 2.1mn b/d in the period between 2013 and 2018.

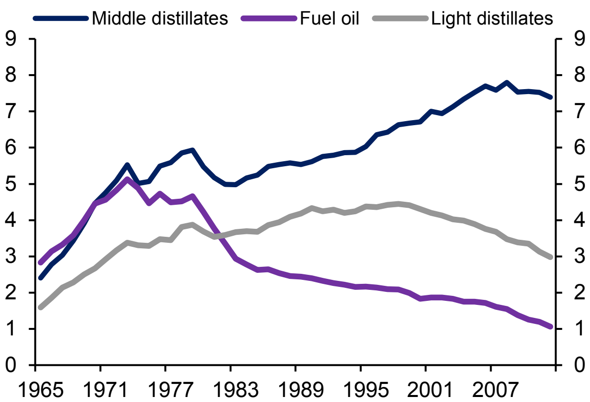
In the US, refiners are benefiting from a combination of abundant cheap domestic crude supplies and the on-going US crude export ban to achieve high refining margins and maximise exports of oil products.

Factoring in the effects of Russia's huge refinery upgrade program, which is expected to boost oil product exports, EU refineries now face an intensely competitive environment.

In addition to the pressure on European refineries that is related to the increased oil product exports from Russia, the US and the Middle East, the on-going depletion in North Sea reserves has further contributed to higher Brent prices. The situation of declining oil output from the North Sea is exacerbated by South Korea's free trade agreement with Europe that has helped to increase crude exports from the North Sea to South Korea since December 2011. The agreement eliminates duties on nearly all trade in goods, making 99% of commerce duty-free over the next five years. This gives refiners in South Korea around $3/bbl discount compared with supplies from other countries. Finally, the loss of crude from some Middle East countries, in particular Libya, has also helped to elevate Brent prices, making it one of the most expensive crudes in the world oil market.

On the demand side the situation is no better. European demand for petroleum products has been falling for a protracted period due to environmental policies requiring improvements in fuel efficiency. This has been compounded by fiscal austerity measures imposed in the wake of the financial crisis, which have caused further weakness in European demand.

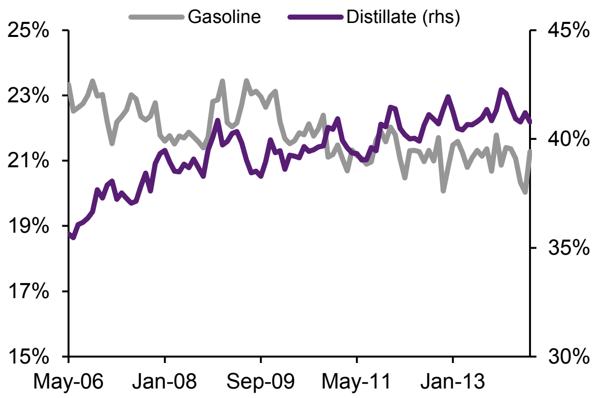
European oil products demand (mn b/d)



Sources: Natixis, BP

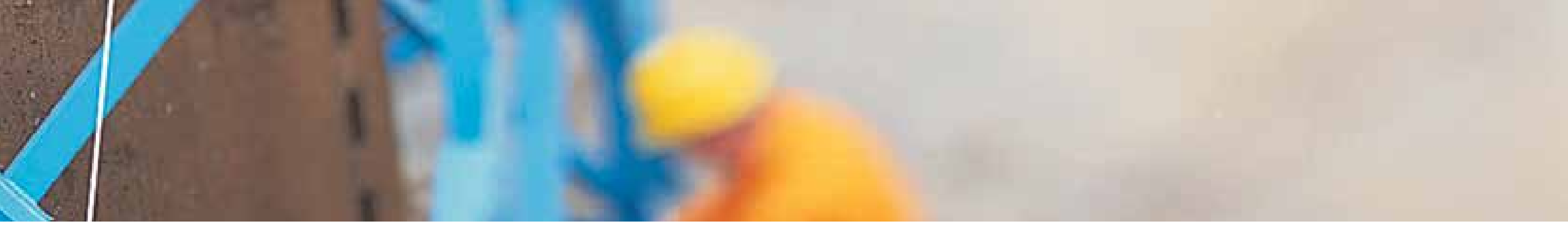
EU refineries were designed to meet strong demand for fuel oil (for heating) and gasoline. As fuel efficiency has become increasingly important over the past two decades, so consumers have increasingly switched from gasoline to diesel. In response, European refineries have boosted diesel yields, which at 40% are one of the highest in the world (vs 22.6% of gasoline), but the imbalance caused by Europe's preference for diesel over gasoline has left refineries with a growing surplus of gasoline. Until recent years, this gasoline could be profitably exported to the US (East Coast in particular). With the rapid expansion in light oil production in the US, however, this export route has become significantly less profitable for European refiners.

OECD Europe - refining yields (%)

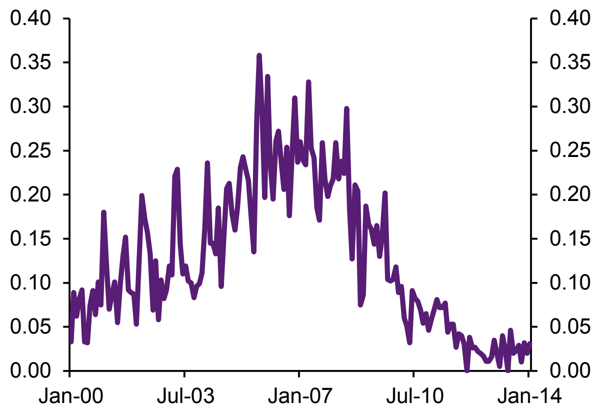


Sources: Natixis, JODI

This combination of high Brent prices, weak European oil product prices and a surplus of unwanted oil products has caused a perfect storm for European refiners in recent years.



US imports of gasoline from OECD Europe (mn b/d)



Sources: Natixis, EIA

IEA projections anticipate an increase in the total yield of middle distillates up to 52.5% in 2035 from 46.6% in 2012 through the closure of refineries with the lowest middle distillates yields and the upgrade of refineries to add middle distillate capacity.

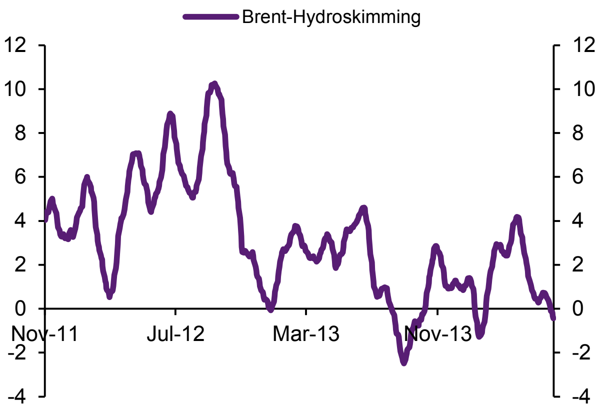
The EU refining sector has been impacted by other environmental legislation, especially in terms of its shipping fuel specifications. While the EU will follow International Maritime Organisation (IMO) decisions on SECA (1 to 0.1% sulphur limit from January 2015), in EU water outside SECA the sulphur limit will be cut to 0.5% in 2020 (depending on the outcome of a review, to be concluded in 2018) from the current 3.5% limit. According to EU refining trade body Europia's estimates, $51bn investment will be required to meet this tougher quality requirement between 2008 and 2020 (including $41bn for the new marine fuel specification). This takes away up to $1/bbl from the refining margin in Europe between 2008 and 2020, increasing the challenges already heaped upon European refineries during this period.

The new Euro-6 emission standards for heavy goods vehicles operating in the EU came into effect in January 2014 and will take effect for light-duty vehicle from September 2014 for all new vehicle in the markets and from September 2015 for all new vehicles sold, increasing operating costs for the existing refiners.

Refining Margins

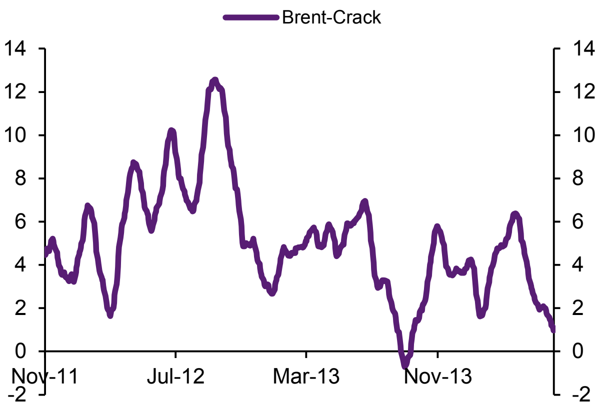
Refining nargins in North West Europe (NWE) and the Mediterranean (Med) have declined due to poor domestic demand and competition from refineries outside the EU area. After refining margins in the Atlantic basin increased temporarily in 2012 due to shutdowns at refineries in Venezuela and the US, EU refiners returned to their loss-making streak once again in 2013. Refining margins in the Rotterdam area for Brent hydroskimming declined by $3.6/bbl in 2013 to measure $1.65/bbl. Similarly, refining margins in the Mediterranean for Urals cracking and topping were down by $2.6/bbl each in 2013. Slightly complex refiners in the Rotterdam area with cracking facilities were able to keep their refineries profitable as margins measured close to $5/bbl, after dropping by $2.8/bbl.

NWE refining margins ($/bbl)



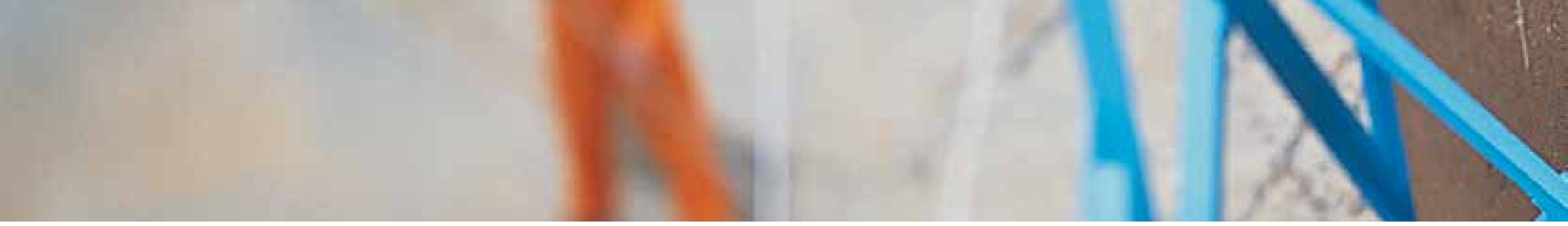
Sources: Natixis, Reuters

NWE refining margins ($/bbl)

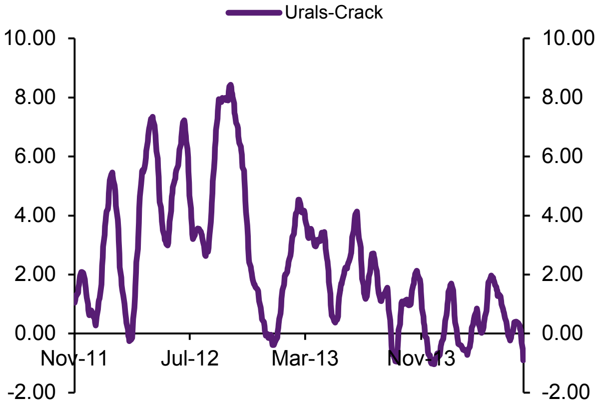


Sources: Natixis, Reuters

In 2014 so far, many refineries have continued to suffer losses as margins for the first half of 2014 for Brent hydro skimming and Brent cracking declined by $1.4/bbl and $1.5/bbl respectively. Refining margins in the Mediterranean region for Urals cracking and topping were down by $1.9/bbl and $1.6/bbl respectively.

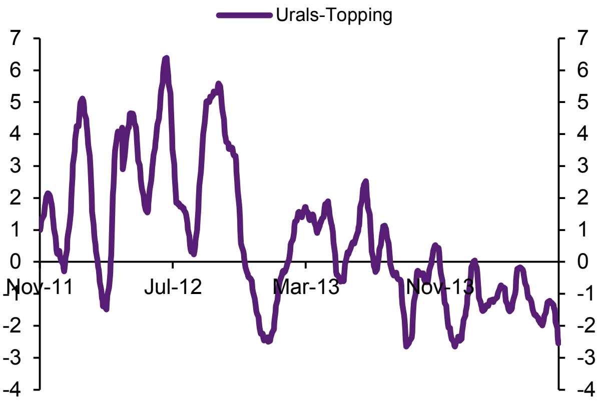


Med refining margins ($/bbl)



Sources: Natixis, Reuters

Med refining margins ($/bbl)

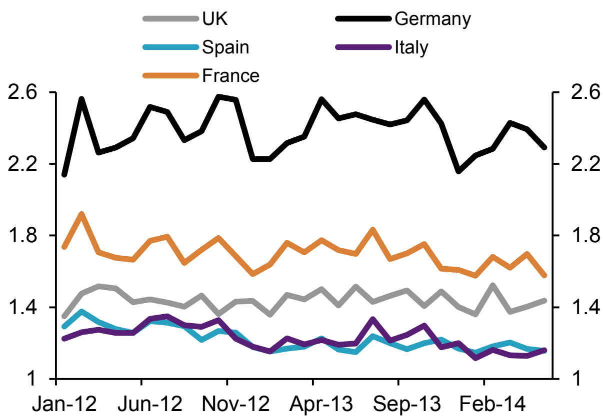


Sources: Natixis, Reuters

EU Oil Demand

Oil demand declined by 1.3% yoy in OECD Europe in 2013. This was a slower pace of decline than the 4% drop in 2012, as some of the key European economies showed signs of recovery in the latter half of 2013. Demand for oil products was almost unchanged, declining by a marginal 0.3% yoy in the last six months of 2013. This improvement in demand was mainly driven by Turkey, Switzerland, UK, Germany and Belgium, followed by Portugal and Norway. To a smaller extent, demand also grew in Austria, Hungary and Luxembourg. Declines continued, however, in Spain, Netherlands, Poland, Italy, France and Greece. Trends in oil demand for the big-5 consumers in the EU is illustrated in the chart below.

European big 5 oil demand (mn b/d)



Sources: Natixis, JODI

Note: Big 5 includes Germany, France, UK, Italy and Spain

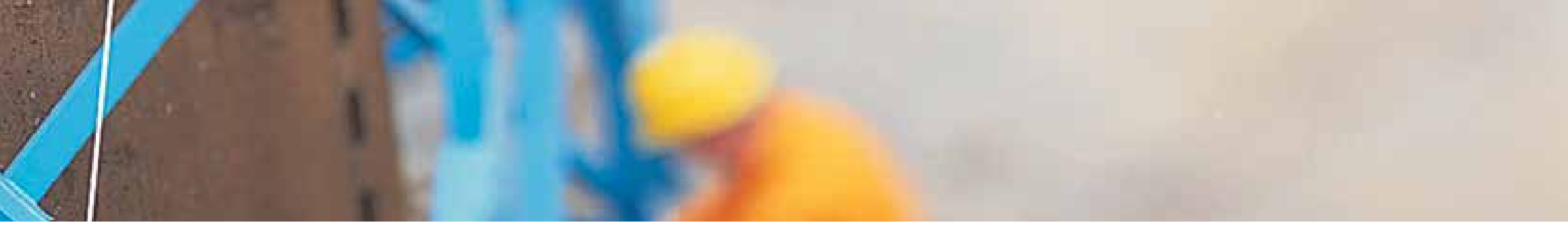
In the first five months of 2014, European demand declined by 2.4% yoy. While Central and eastern Europe experienced growth in demand emanating from Poland, Turkey, Czech Republic, Estonia and Hungary, demand was significantly down for France, Italy, Germany, Switzerland and UK. Weak demand for oil in Germany, the power-house of Europe, clearly suggests slower growth in industrial activity. Warm weather also led to lower demand for gasoil so far in 2014. Signs of negative growth in Italy and weak PMI numbers in France suggest further challenges ahead for the European economy in 2014.

Natixis forecasts project Eurozone, UK, eastern Europe and Turkey's GDP to grow by 1% yoy, 2.5% yoy, 2.9% yoy and 2.9% yoy respectively in 2014. However, poor economic conditions in the EU, particularly France and Italy, could slow the overall recovery in EU demand. We expect OECD Europe's demand to remain weak in 2014 on the back of weak European economy. In 2015, we expect OECD Europe's demand to stabilise as EU economy recovers along with the growth in global economy.

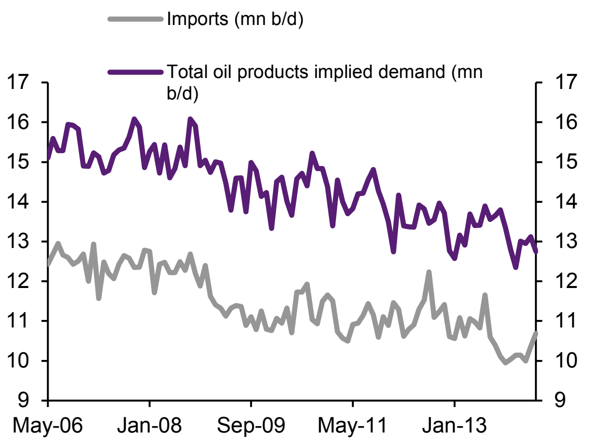
Europe refining margin comparison ($/bbl)

			2013		2014 (Jan-Jun)	
Region	Refinery type	Crude	Average refining margin	yoy change	Average refining margin	yoy change
Rotterdam	Hydroskimming	Brent	1.65	-3.57	1.32	-1.36
Rotterdam	Cracking	Brent	3.99	-2.84	3.44	-1.51
Rotterdam	Topping	Urals	0.59	-2.79	-0.59	-2.39
Mediterranean	Cracking	Urals	1.62	-2.57	0.39	-1.97
Mediterranean	Topping	Urals	-0.11	-2.57	-1.24	-1.69

Sources: Natixis, Reuters

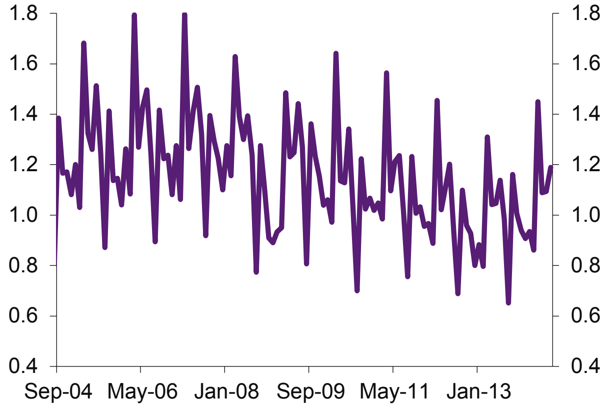


OECD Europe - crude imports vs oil products demand (mn b/d)



Sources: Natixis, JODI

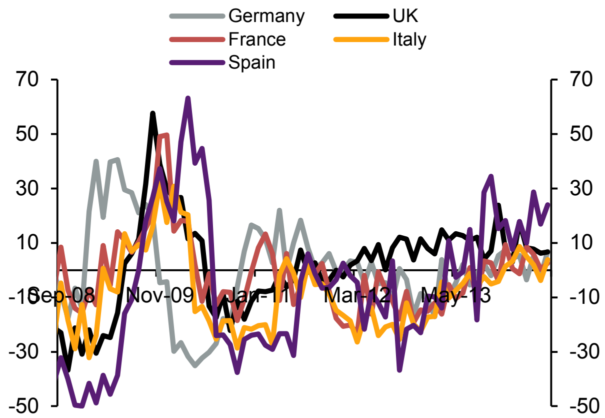
Passenger car sales in Europe (mn)



Sources: Natixis, Bloomberg

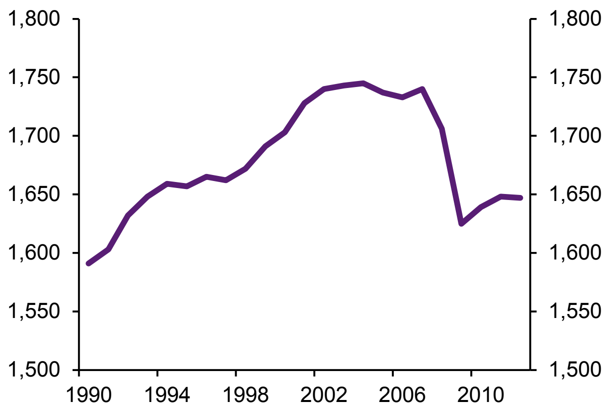
Vehicle efficiency improvements will continue to impact European gasoline demand. Increased passenger vehicle sales so far in 2014 have replaced ageing and inefficient cars with newer, smaller, more efficient vehicles. Average engine size of new vehicles has declined, from highs of 1,740cc in 2007 to 1,621cc in 2013, the lowest since 1992. Improved combustion processes and turbocharging allow manufacturers to extract more power from small engines, hence substituting 6-cylinder engines by 4-cylinder engines.

European car sales (%, yoy)



Sources: Natixis, ACEA, Bloomberg

Average CC of new registered car



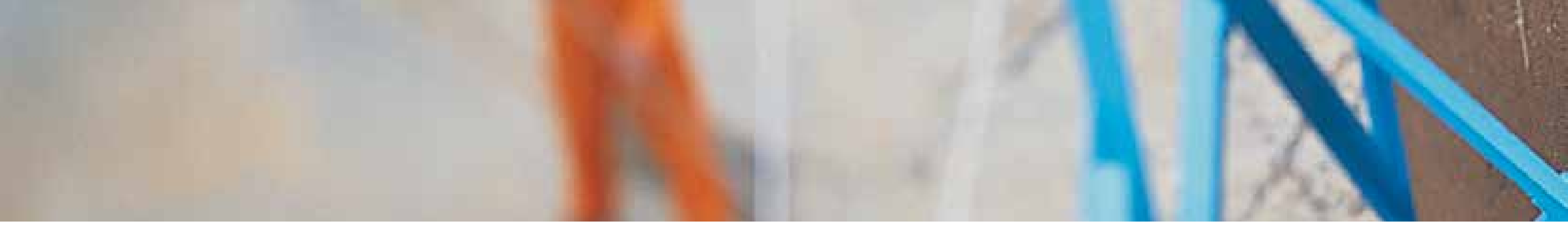
Sources: Natixis, ACEA

Note: Western Europe includes EU15+EFTA

European (EU-28) passenger car registrations increased by 6.5% yoy in 2014H1, totalling 6.62mn units after declining by 1.5% yoy in 2013. This was driven by stronger sales in western Europe, Spain and UK in particular.

The registration of commercial vehicles in the EU-27 rose by 9.3% in the first half of 2014. Most of the rise in commercial vehicles was in light commercial vehicles (3.5tonnes), sales of which were up 10.9% yoy vs the same period whereas sales of heavy trucks (16tonnes) were up by 5.7% yoy. All major markets saw a rise in the sales of LCV. In the HCV category, major markets other than France and UK performed well.

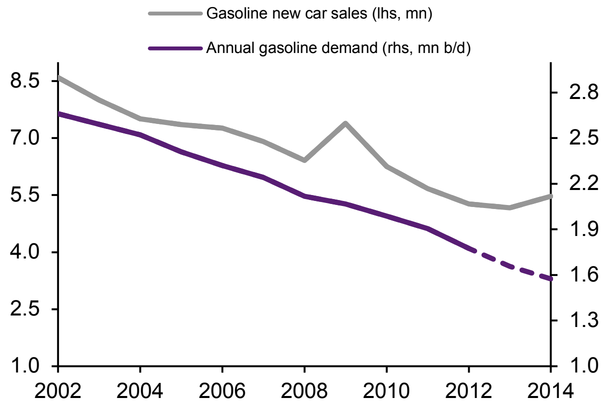
Tightening of sanctions on Russia and potential counter -sanctions from Russia on EU could impact the EU economy severely and hence also the demand for oil products. Although demand for oil products is likely to decline in general, we could see an unexpected increase in demand for gasoil, particularly in the winter months, if Russian cuts off gas supplies to EU in retaliation.



Gasoline

European gasoline demand declined by 3% yoy in 2013. New gasoline-powered car sales in the EU were down by 2% yoy in 2013 due to the on-going increase in diesel car penetration. Due to the increase in overall car sales in the EU (gasoline and diesel) in 2014, as individuals and companies replace their ageing and inefficient fleet with new vehicles, gasoline car sales are expected to rise by up to 6% yoy this year. Despite this increase in vehicle sales, demand for gasoline fuel may not improve by nearly as much due to improving car efficiencies. Miles per gallon is expected to rise from 45mpg in 2010 to 49mpg in 2015 and ultimately to 65mpg in 2020. This is substantially higher than US requirements of 42.5mpg in 2020. So far in the first half of 2014, gasoline demand in Europe has fallen by 2% yoy to measure 1.84mn b/d.

Western Europe - new car sales vs gasoline demand



Sources: Natixis, ACEA

Note: Western Europe includes EU15+EFTA, Natixis forecast for 2013 based on extrapolation of 2013H1 data, 2014 data is based on Natixis economic growth forecasts for euro area.

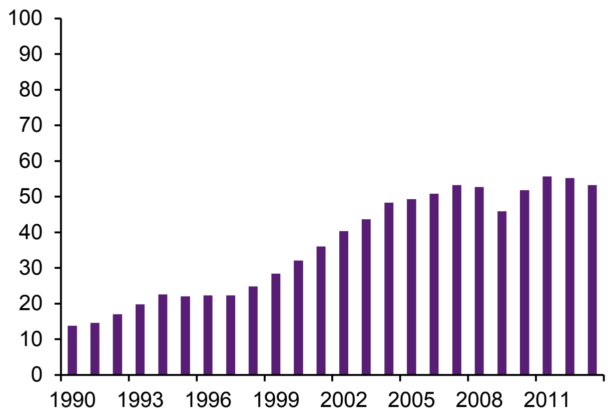
The latest data by Eurostat on performance of passenger transport indicates that passenger km travelled by car have been declining since their peak in 2009, falling by 0.7% in 2010 and 0.2% in 2011. We would expect similar decline rates from 2012 onwards, including in 2014.

Eurobob prices in the first half of 2014 have averaged $977.45/tonne. Gasoline prices in Europe have remained above $950/tonne for the last 4 years, after averaging $700 or lower prior to 2010 (with 2008 as an exception). As gasoline demand is price elastic, we would expect demand to have been impacted negatively by these higher gasoline prices, hence the decline in passenger km travelled.

Distillates

European distillates demand increased by 0.2% yoy in 2013. Most of the increase in demand emanated from UK, Turkey, Switzerland, Germany and France which counteracted the steep decline in demand for diesel from Greece, Italy, Spain and Poland.

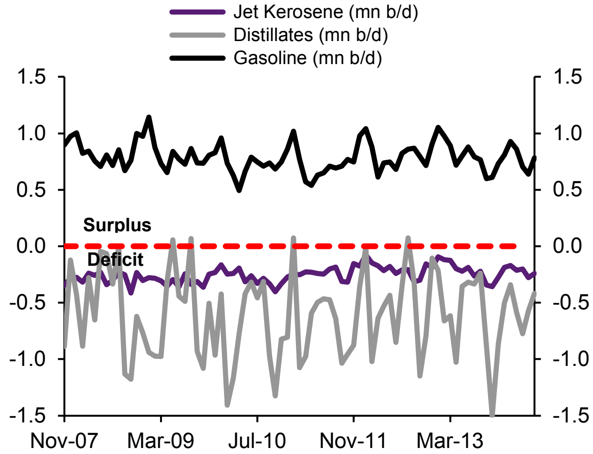
% share of diesel in new passenger car registration in western Europe



Sources: Natixis, Reuters

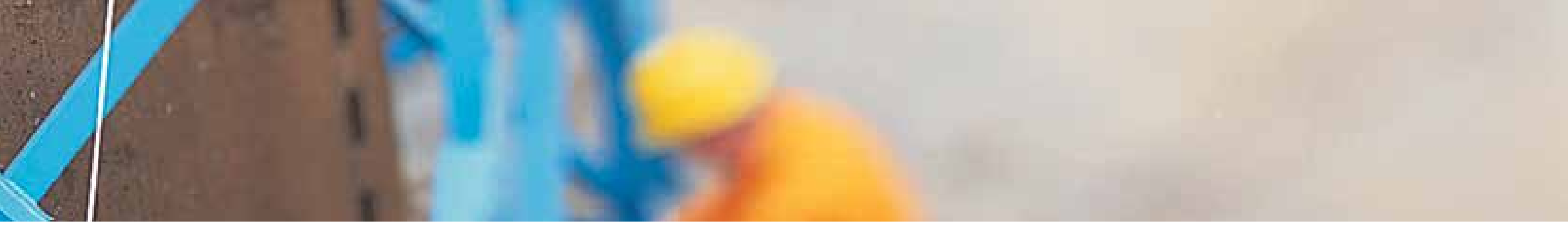
Diesel car penetration is high in western EU and it has continued to rise, albeit marginally, increasing in 2013 to 55.3%. In addition to passenger cars, most commercial vehicles run on diesel. Sales of commercial light-duty and heavy-duty trucks were up in 2014. This has led to increased diesel yields for European refiners as they try to fill the large demand-supply deficit created in Europe.

OECD Europe-oil products surplus/deficit



Sources: Natixis, JODI

In a potential reversal of this trend towards diesel-powered vehicles, concerns that diesel engines cause higher pollution are beginning to emerge, with particularly acute problems seen in many European cities in the spring of 2014. Even

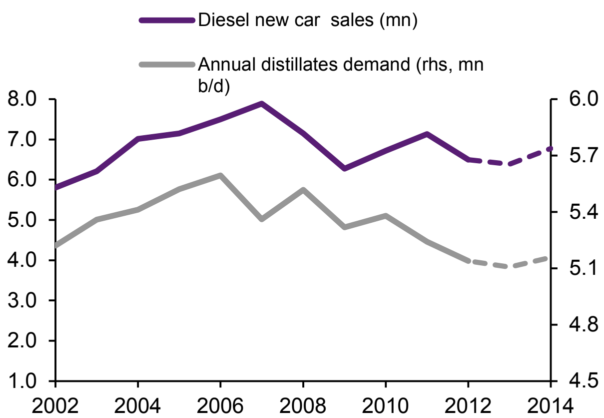


though new diesel engines with the correct filtration systems fitted will result in very low emissions of CO2 and particulates, political pressure to equalise the tax treatment on gasoline and diesel could impact negatively upon diesel demand, at the same time pushing up gasoline demand.

European freight transport by road declined by 1.25% yoy in 2011, according to the latest data from Eurostat. We expect similar decline rates in 2012 as the EU economy continued to shrink. Freight transport growth is expected to have increased in 2013 as GDP growth and PMI indices improved from the second quarter of 2013, which was evident in stronger European demand for distillates from April 2013 to December 2013. According to ACEA, trucks transport 18bn tonnes of goods per year, which is roughly 75% of all goods carried over land in Europe.

So far in first five months of 2014, demand for distillates is down by 3% yoy to measure 5.7mn b/d, thanks to a combination of factors including weakness in the economy and also a relatively warm winter. Efficiency gains in trucks and passenger cars will further exacerbate this decline.

Western Europe - new car sales vs distillates demand



Sources: Natixis, ACEA, JODI

Note: Western Europe includes EU15+EFTA, Natixis forecast for 2013 based on extrapolation of 2013H1 data, 2014 data is based on Natixis economic growth forecasts for euro area.

ULSD prices declined by 4.2% yoy (-$41/tonne) in 2013. Prices fell further in the first half of 2014, down by around $8/tonne. Since 2011, gasoil prices have averaged around $950/tonne, substantially higher than the lows of around $600-650/tonne prior to 2011 (except 2008). We expect gasoil prices to be supported by the changes in EU bunker fuel law by end of this year, on top of increasing gasoil demand-supply deficit due to the shut-down of unprofitable refineries.

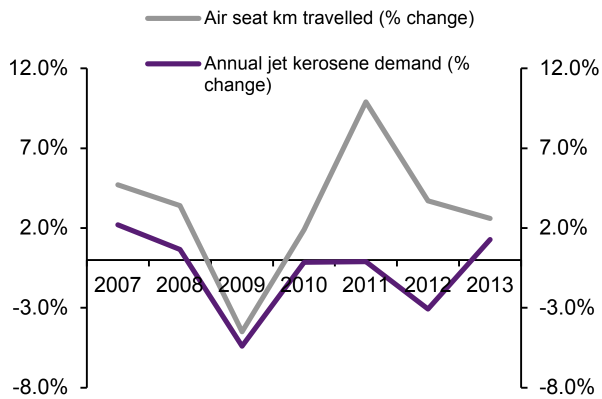
Jet Kerosene

European demand for jet kerosene increased by 1.3% yoy in 2013 to average 1.23mn b/d. Jet kerosene demand is correlated to total air seat kilometres travelled in the EU, as illustrated in the chart. Air seat km travelled is heavily seasonal, driven by the timing of annual holidays. Hence European imports of jet kerosene are also seasonal as domestic refining capacity is insufficient to meet seasonal peaks.

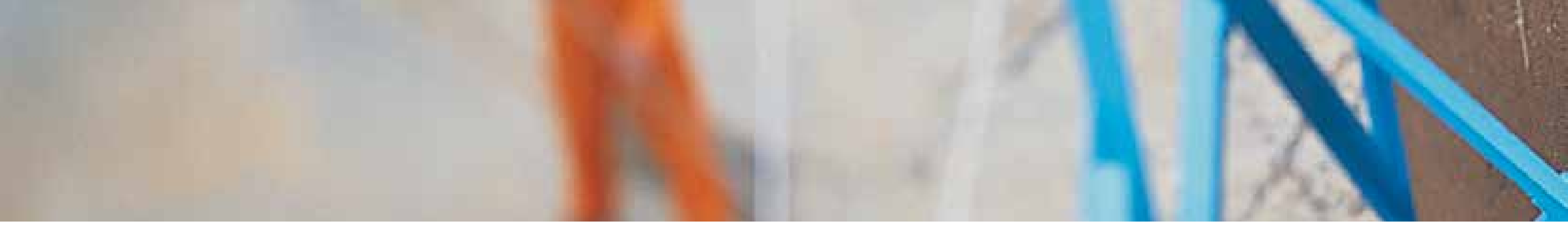
European carriers saw traffic rise 3.8% in 2013 compared to 2012, a slowdown compared to annual growth of 5.3% in 2012. Capacity rose 2.8% and load factor was 81% in 2013, second highest among the regions and a 0.5% pt rise over 2012. Modest economic improvements in the EU-27 since the third quarter of 2013 and rising consumer and business confidence provided a stronger demand base for international travel; and after weakness in the earlier part of 2013, job losses in the EU stabilized at the end of 2013. Unemployment in the EU-27 has declined from 10.9% in June 2013 to 10.2% in June 2014, according to Eurostat.

Jet kerosene demand from Jan-May 2014 averaged 1.16mn b/d, down 1% yoy so far this year. We expect demand to remain weak in 2014. Escalation in Russia-Ukraine crisis could further impact air travel, not just to Russia but also to countries that require travelling over Russian or Ukrainian air space. If the European economy recovers in 2015, as expected, then we could see an increase in air passenger kilometres travelled next year and hence an increase in demand for the aviation fuel.

OECD Europe - jet kerosene demand growth



Sources: Natixis, JODI, IATA

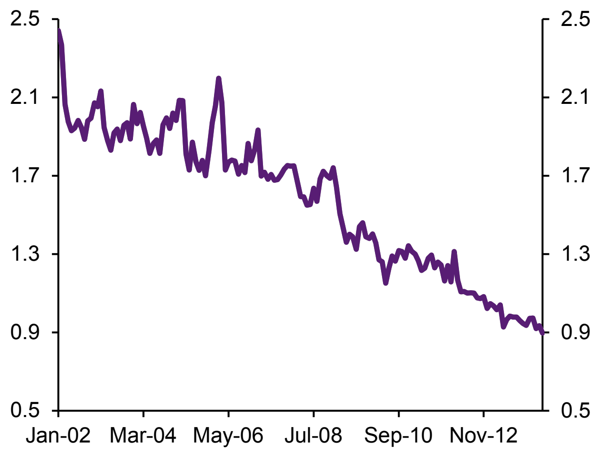


Fuel Oil

European residual fuel oil demand declined by 11.6% yoy in 2013. So far in first five months of 2014, it is down by 9% yoy to measure 940,000b/d.

The maximum permissible sulphur content in ECAs is scheduled to be reduced to 0.1% in 2015, considerably below what is feasible for maritime bunker fuel oil. Hence, in the near term, the demand for fuel oil is likely to be replaced with maritime gasoil. Current maritime fuel use in EU ECAs is estimated at 367,000b/d (20mn tonnes), of which the majority is bunker fuel oil. In other words, these tighter limitations mean EU refiners will need to supply an additional 112,500b/d (15mn tonnes) of gasoil to the shipping industry in 2015. Building the 10 upgrading projects needed to produce this gasoil would require an investment of $6-7 bn. If these investments are not made in Europe, reliance on foreign imports will only increase.

OECD Europe - residual fuel oil demand (mn b/d)



Sources: Natixis, JODI

Eventually ships will have to switch to gasoil (MGO), which would be the only option among the fuel grades presently available. Furthermore, as the demand for it increases, marine gasoil will also presumably go up in price. As an alternative to low-sulphur fuels, ships can opt for LNG-powered ships. European Commission has encouraged the use of marine LNG as ship fuel through the expansion of LNG-bunkering facilities around the EU coastline. EU transport funding instruments, such as TEN-T and Marco Polo Programmes give financial support to green maritime-based projects. But until recently neither ship owners nor ports wanted to take the first step in investing in LNG-based facilities. Member states, the European Commission and the European Parliament agreed in 2014 to ensure that a sufficient number of big European ports would have developed LNG refuelling infrastructure for maritime transport by 2025.

From July, first inland shipping can officially bunker with LNG in the Seinehaven, in Rotterdam Botlek, which is a first for Europe. An increased global interest from ship operators has been witnessed in recent months with contracts for building the first LNG-fuelled ferry for domestic Danish trade being signed in June 2014. The ship will be the first LNG-fuelled ferry designed for domestic trade in the European Union. The effort is still limited and the deadline set by EU is also applicable in the long term. In the near term, we would expect LNG to displace only limited volumes of marine gasoil, if any .

A second challenge is the proposed tightening of the MARPOL global specifications from the current 3.5% to 0.5% sulphur in 2020. Global maritime fuel demand is expected to increase from 200mn tonnes in 2010 to 250mn tonnes in 2025.

European oil demand (mn b/d)

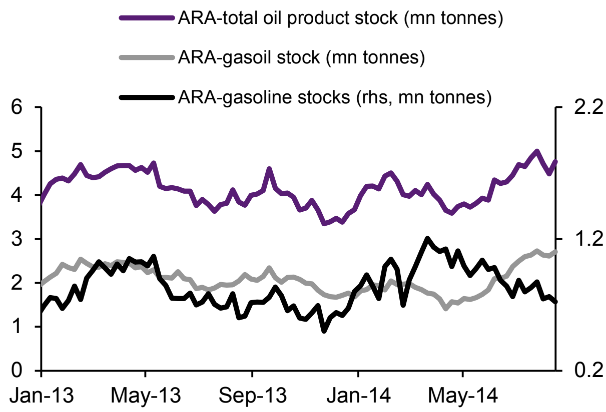
	2013	2014	2015
ESAI	14	13.8	13.7
IEA	13.65	13.56	13.53
EIA	13.62	13.5	13.47
OPEC	13.59	13.41	

Sources: ESAI, IEA, EIA, OPEC

Oil Product Stocks

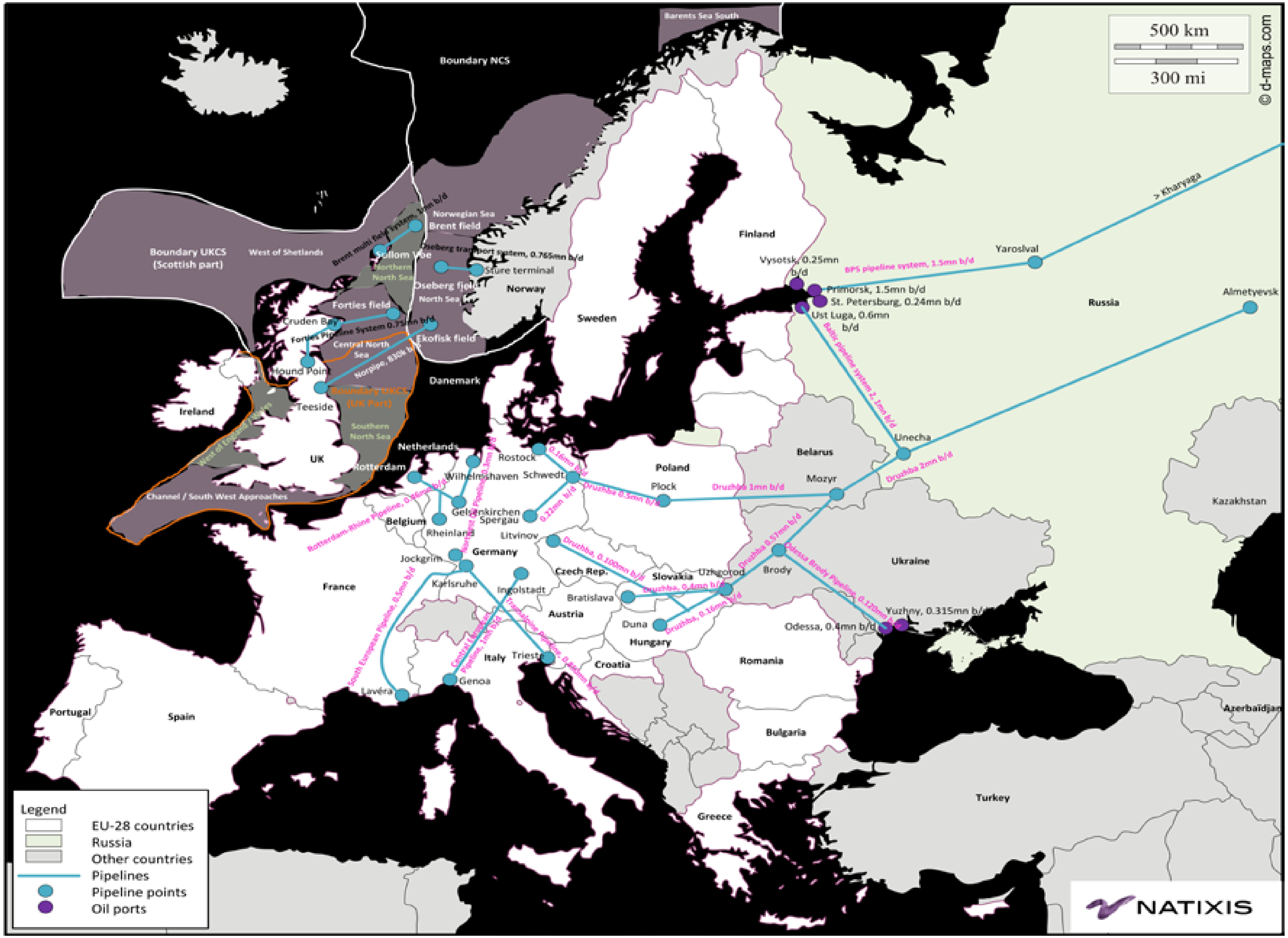
Oil product stocks in the ARA region increased by 85%yoy in the first six months of 2014, due to lack of demand. Gasoil stocks were up 320,340tonnes yoy in 2014H1 and stocks of gasoline were up by 468,807tonnes yoy for the same period.

EU total oil products stockpile



Sources: Natixis, PJK, Bloomberg

Main European Oil Pipelines



Sources: Natixis, D-maps

Oil Price Outlook | South America | North America | **Europe** | Russia | Executive Summary

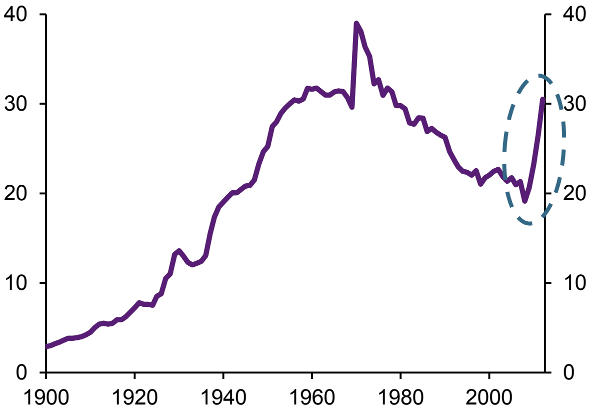
United States

US crude oil production has risen rapidly over the past two years, touching 8.5mn b/d for the first time since the mid-1980s, mainly thanks to the shale revolution. Shale oil now accounts for approximately 3.5mn b/d, 44% of total US output. A resurgence in US oil output has also led to rapid growth in US oil infrastructure. With US oil prices remaining well below global prices, US oil companies are exploring ways of circumventing the US ban on exports of crude in order to benefit from the higher international oil prices.

Reserves

US crude oil proven reserves have increased since 2008 after declining for close to three decades, according to the US Energy Information Administration. From 19.12bn bbl in 2008, proven reserves measured 30.5bn bbl in 2012. An additional 2.9bn bbl was attributed to lease condensates in 2012. Both NGL and crude reserves were up 15.4% yoy in 2012. This increase has been mainly due to a large extension to existing fields, particularly in Texas and North Dakota. According to BP, US crude reserves numbers are somewhat higher, estimated at 44.2bn bbl in 2012 and 2013. The growth is due to America's shale oil boom, with horizontal drilling technology unlocking vast reserves in the Bakken, Eagle Ford and Permian basins. Furthermore, new shale plays continue to be discovered in the US, which means oil reserves may continue to grow significantly in the coming years.

US crude oil proven reserves (bn bbl)

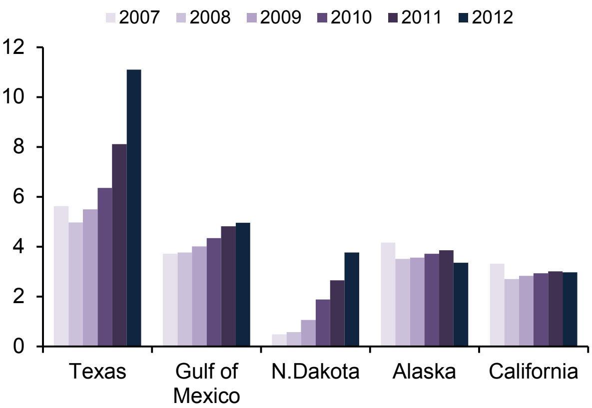


Sources: Natixis, EIA

Note: On-shore and off-shore

Proven crude oil reserves in the Eagle Ford tight oil play in southwest Texas surpassed those in the Bakken formation of North Dakota to become the largest tight oil play in the United States.

2007-2012: US proven crude reserves (bn bbl)



Sources: Natixis, EIA

According to a recent USGS survey updated in 2013, US total mean undiscovered oil reserves (on-shore) were 53.41bn bbl, with 24.4% attributed to shale and tight oil and another 25% coming from NGLs. The mean is calculated by taking an average of P5%, P50% and P95% undiscovered reserves. Current USGS estimates also suggest around 48bn bbl of undiscovered technically recoverable deep-water reserves in the Gulf of Mexico (GoM).

Total mean undiscovered onshore oil reserves 2013

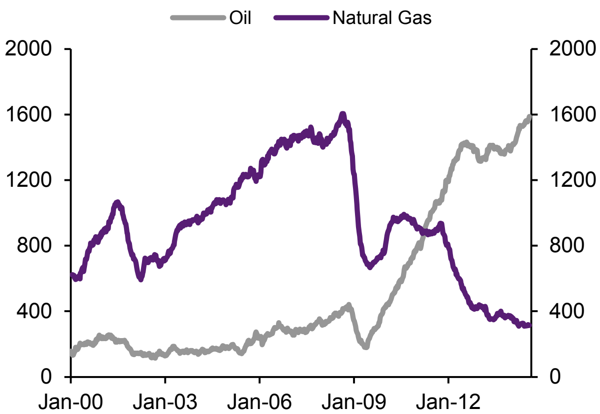
Reserves	bn bbl
Conventional	27.24
Continuous, tight oil & shale oil	13.04
NGL	13.13
Total excluding NGL	40.28
Total including NGL	53.41

Sources: Natixis, USGS

Drilling Activity

US rig counts did not change much on average between 2012 and 2013 after rising exponentially between 2009 and 2012. Part of the reason for this stagnation was that more wells could be drilled per rig, thanks to the increased efficiency of rigs. However, we also expect a second factor which is US oil take-away capacity which was lagging behind production. There has been a small rise in US rig count activity since November 2013, which we believe is due to increased crude take-away capacity from remote oil producing regions.

Oil & gas rig count



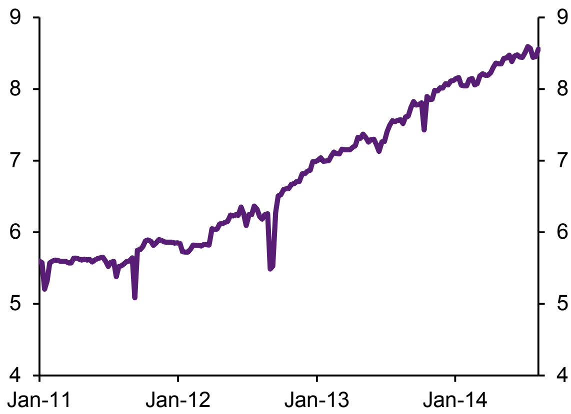
Sources: Natixis, Baker Hughes, Bloomberg

The US well-count is expected to rebound in 2014, as a result of a combination of factors including increased drilling efficiency and the continued shift to horizontals in the Permian basin. The US land wells to rig ratio increased to 5.34 in 2013Q4 from 4.92 a year ago. According to Baker Hughes, US onshore rigs will average 1,710 (flat vs 2013) and off-shore rigs will average 60 (up 5% yoy). Despite the flat rig count, the US onshore well count will increase 5% compared with last year because of continued growth in drilling efficiency. Oil & Gas Journal (OGJ) expects horizontal rigs in the Permian basin to increase 35% and horizontal wells drilled overall to increase nearly 40% from current levels.

Oil Production

US oil production increased by 900,000b/d in 2013. This was mainly driven by shale oil growth which was boosted by improved drilling efficiency and multiple well-drilling pads. The three main shale producing regions, namely Bakken, Eagle Ford and Permian, were producing 1.07mn b/d, 1.4mn b/d and 1.5mn b/d respectively in June 2014. Other shale oil is coming from Haynesville (53,000b/d), Marcellus (42,000b/d) and Niobrara (315,800b/d).

US crude oil production (mn b/d)

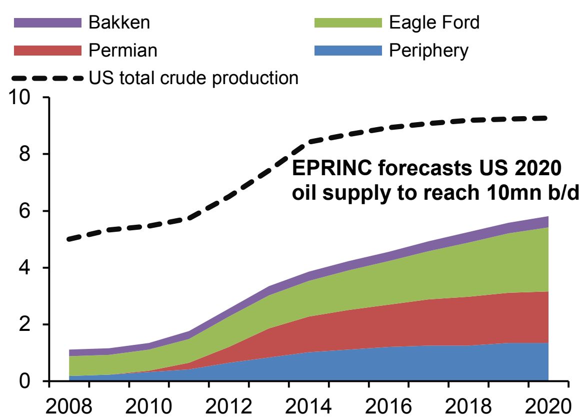


Sources: Natixis, Bloomberg

Production Forecasts

Based on increased capex, improved technology, increased and more efficient rig activity, increased 1P reserves and increased crude-takeaway capacity, we expect oil production to increase by up to 1mn b/d in 2014. US oil output is expected to reach 10mn b/d in the medium term (2017-2020).

US total oil supply vs shale oil supply (mn b/d)

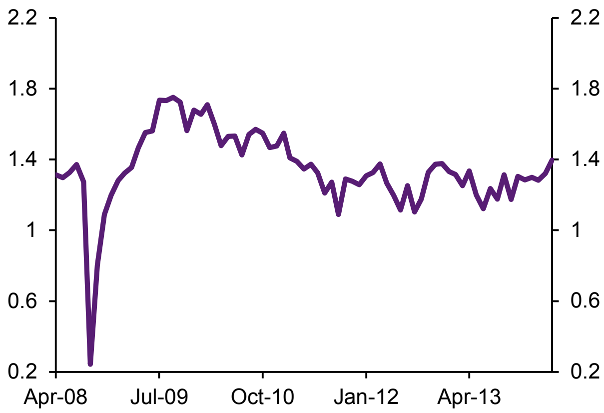


Sources: Natixis, EPRINC, EIA, HDPI

We expect an increase in oil production in the Permian basin as many oil producers switch to horizontal drilling that increases initial production rates.

Development of the Gulf of Mexico has been slower than the shale plays. Drilling costs are substantially higher and have increased further in recent years as the geological complexity has become better understood. On top of this, regulations have been made more stringent as a result of the Deepwater Horizon incident. Costs are now in excess of $100mn per well. As a result, only very well capitalized companies can participate. In the last few years, operators have intensified exploration and development efforts in the deep-water portions of the Federal GOM. Oil production from offshore fields is expected to resume an upward trajectory.

US crude output-GoM offshore (mn b/d)



Sources: Natixis, USDOE

Federal GOM production is expected to increase from 1.37mn b/d in November 2012 to over 1.6mn b/d by the end of 2014. Most of the incremental production from the Gulf of Mexico is heavier, similar to 28-29 °API Mars.

New platforms by Shell have started producing in 2014 from their Olympus platform (Mars B project) and are expected to start their Cardamom project soon. Other major projects coming online in 2014 include Chevron's Jack field project which will be operational by end of 2014. Chevron's other major project Big Foot will be operational in 2015. Enterprise Products expects total GoM crude production to reach 2.3-2.7mn b/d in 2020.

Capex

Oil and gas industry capital spending in the US will increase by 5.2% in 2014 to $338bn, according to Oil & Gas Journal's (OGJ) annual spending report.

OGJ estimates that spending in the US for upstream operations will increase 9.3% this year to $299bn. US exploration and drilling spending this year is estimated at $250bn, up 9.3% from last year. Outlays for production this year will total $47.5bn, up from $43.5bn last year. From an oil and gas perspective, most of the spending growth is expected to be on the oil side, given the current commodity price levels. Apart from E&P, capex will also be driven by transport infrastructure spending.

More capital will be allocated to Alaska in 2014 vs 2013, resulting from the passage of the More Alaska Production Act (SB21).

Gulf of Mexico major off-shore projects 2014/2015

Operator	Project	Start Date	1000 b/d
Shell	Cardamom	2014	50
Anadarko	Lucius	2014	80
Chevron	Big Foot	2014/15	79
Hess	Tubular Bells	2014	40
Hess	Stampede	2014	
ExxonMobil	Hadrian South	2014	
Chevron	Jack/St. Malo	2014	94
Shell	Mars B, W.Boreas, S.Deimos	2014/15	100
Murphy	Dalmation	2015	7
Anadarko	Heidelberg	2016	80
ExxonMobil	Julia	2016	34
Shell	Stones	2016	50
Shell	Appomattox	2017/18	150
Shell	Vito	2017/18	100

Sources: Natixis, Turner Mason & Company

US spending plans 2012-2014

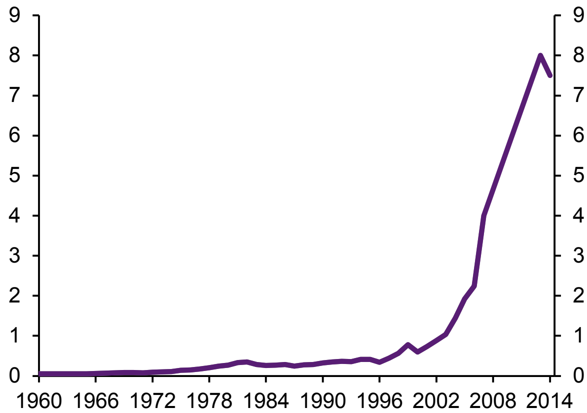
Million $	2014	2013	2012
Exploration-Production	**299,340**	**273,748**	**286,469**
Drilling-exploration	250,202	228,948	239,205
Production	47,538	43,500	45,449
OCS Lease Bonus	1,600	1,300	1,815
Other	**38,917**	**47,882**	**27,382**
Refining-Marketing	12,900	12,800	13,000
Petrochemicals	5,600	3,709	2,400
Crude & products pipelines	9,207	15,804	3,028
Natural gas pipelines	3,660	9,169	3,554
Other transportation	2,750	1,800	1,200
Miscellaneous	4,800	4,600	4,200
Total	**338,257**	**321,630**	**313,851**

Sources: Natixis, OGJ

Economics

According to Wood Mackenzie, the cost of new wells in 2014 will average $7.5mn per well vs $8mn in 2013. Hess Corporation reported an 18% yoy drop in well costs in 2013Q3 due to improving efficiencies as it took fewer days to drill one well and as wells were closer to each other. For Wood Mackenzie, 70% of the oil reserves will remain economic with global oil prices at $75/bbl.

US nominal cost per crude oil well drilled



Sources: Natixis, EIA, Wood Mackenzie

High decline rates in shale oil plays lead to high capital costs which can be disproportionately large for smaller companies. Some of the small independents (especially wildcatters) are therefore at risk of becoming over-leveraged and as a result have high interest costs. Our own analysis suggests the breakevens are in the range of $55-90/bbl, based on Bakken and Permian basin decline rates of 80%, average cost per well of $8mn and initial flow per well of 380b/d for Bakken vs 120b/d for Permian. This analysis nevertheless excludes any natural gas based sales which, even if limited, would offset some of the costs.

According to the CEO of a large US oil company, $100/bbl oil is the new $20/bbl as costs rise. Among the rising costs have been those for offshore development, which now reach into waters that are deeper and more obscure than were possible a decade ago. Costs for offshore rigs have climbed more than five-fold in the last 10 years.

The IHS CERA Upstream Capital Cost Index (UCCI) suggets upstream costs have more than doubled since 2000. The UCCI is similar to CPI, and tracks the composite cost of equipment, facilities, materials and personnel in a geographically dispersed portfolio of projects.

Improved technology and the use of cheap natural gas as a fuel will help reduce some of the fixed and operational costs, as follows:

- Multi-well drilling pads
- Extended reach horizontal laterals up to 2 miles in length
- Optimization of hydraulic fracturing through micro seismic imaging and enhanced interpretation
- Simultaneous hydraulic fracturing of multiple wells on a pad
- Drilling bits designed for specific shale and tight formations
- Further improvements in technology, such as selective fracturing along the horizontal lateral (the horizontal section of a well) to avoid zero or low production stages, based on local geologic characteristics, might further improve the economics of tight oil production.

These factors will help counter the rising costs of shale oil wells and high decline rates.

Crude infrastructure

Pipelines are the main mode of transporting crude oil in the US. More than 60mn barrel per month of crude flows by pipeline between PADD1, PADD2, PADD3 and PADD4. The costs of transporting crude by pipelines are usually much less than other modes of transportation, especially when considering large volumes. Hence many pipeline companies have either expanded existing pipelines or invested in new pipelines in recent years. The other key modes of crude transportation include railroad, barges and trucks.

The dynamics of pipeline flows between PADD regions have changed significantly with the resurgence of US light oil. Oil movements between PADD2 to PADD3 and PADD4 to PADD2 have risen significantly, with the rise in PADD2-PADD3 being +400% since the beginning of 2012. Oil is flowing from shale-rich regions of the Midwest (PADD2 and PADD4) to the refining hub of the US which is the Gulf Coast. Before the expansion of US shale oil, crude imported by the US used to flow from the Gulf Coast to Midwest refiners. However, crude oil movement from PADD3 to PADD2 has declined as pipeline flows on key north-bound pipeline such as Seaway have been reversed.

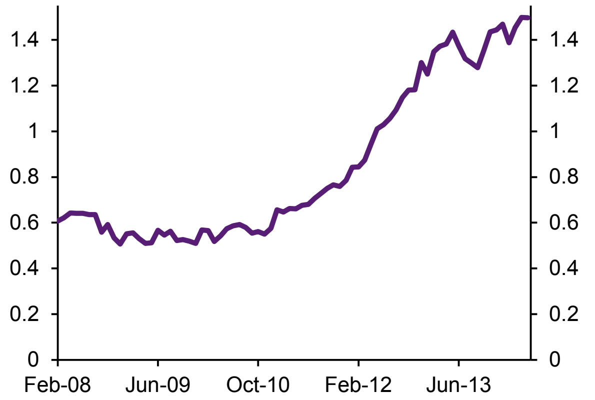
Investments in US crude oil pipelines have increased by $5bn over the past three years to $6.6bn in 2013. Although pipeline projects have not kept up with the pace of crude oil production in the US, there are several pipelines projects under development and we expect investment in pipelines to continue for the next 3-4 years (by then US oil output is expected to peak) to support the growth in oil supply. Starting with the original Keystone pipeline commissioned in 2010 and the reversal of several other existing pipelines between the Upper Midwest and Midcontinent, a large-scale reshaping of domestic crude oil flow patterns is underway. Total pipeline capacity additions will be around 2.8-2.9mn b/d in 2014 and 1.2-1.5mn b/d in 2015. Some of the pipeline additions for 2014 and 2015 are illustrated in the North American pipeline chart. In 2014, the major Cushing inbound pipeline projects include Pony Express with 220,000b/d capacity (2014Q3) and Flanagan South with 585,000b/d capacity (2014Q3). White Cliffs is expected to expand in 2014Q3 as well (80,000b/d). On the Cushing outbound front, Seaway expansion will add a further 450,000b/d by 2014Q3. Also the Market Link pipeline, which came online last year, is yet to ramp up to its full capacity.

Due to the long timeline for pipeline construction, political hurdles and cost of investment, many refineries as well as oil companies have used the existing US rail network to deliver oil. For example, Canada is considering a rail alternative to the Keystone pipeline.

Some other advantages of crude-by-rail over pipeline include:

- Large pipeline projects cost billions vs railway projects and loading terminals which costs millions. Typical costs to build unit train terminals are between $30-$50mn with a capital payout of 5 years or less. A train loading terminal can be built in about 12 months.
- Railways do not require long term contracts. Refineries are unwilling to enter into 10 year contracts at the moment due to excessive crude supply.
- Less or no diluent is required when transporting bitumen type crude

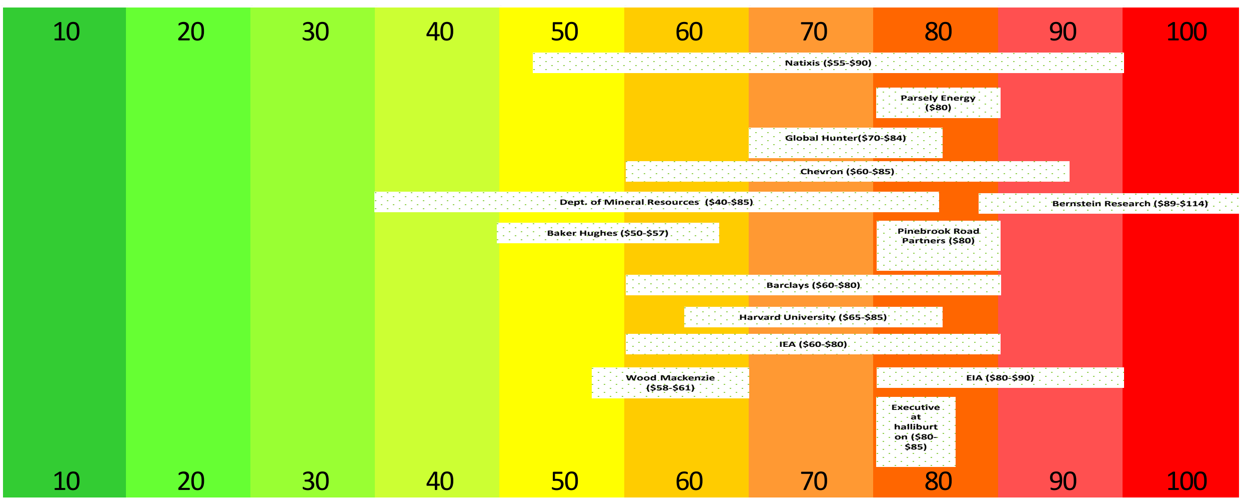
Petroleum deliveries by rail (mn b/d)



Sources: Natixis, AAR

Crude oil movements by rail have increased by over 750,000b/d over the last 3 years to reach 800,000b/d in 2013, driving capital investment in rail tracks, rail loading and unloading facilities, and tank cars used in the transportation of crude oil. 2013 represented a milestone year for investment in crude dedicated rail cars as well as crude loading and unloading facilities, with total investment of $3.6bn. This will likely represent the peak investment year for dedicated crude-by-rail infrastructure. In 2014, we would expect similar spending in crude-by-rail infrastructure, but beyond that we would expect to see a fall in spending once pipeline infrastructure is sufficiently developed. In 2014, crude oil loading and unloading capacity additions

Breakeven prices ($/bbl)



Sources: Natixis, various

across the US rail network will be around 1.05mn b/d and 1.42mn b/d respectively. According to the US congressional research service, US crude-by-rail deliveries will increase from 820,000b/d in 2013 to 1.8mn b/d in 2014. In April 2014, total US rail-based petroleum deliveries (oil & oil products) were 1.5mn b/d, up 115,000b/d yoy.

Barging activity has also increased, but not as much as rail. Barging offers a partial solution to transporting oil. Increased barge and rail-to-barge activity was seen in the US in 2013. According to the Department of State in their report on Keystone XL pipeline, rail to marine trans-loading terminals in the PADD2 region will increase from 210,000b/d in 2013 to 450,000b/d in 2016. Oil movement by tanker and barges was up from around 2mn b/d in October 2012 to almost 5mn b/d in October 2013.

Refinery Receipts

While refinery receipts of crude by truck, rail, and barge remain a small percentage of total receipts, EIA's recently released Refinery Capacity Report shows refineries across the nation received more than 1.58mn b/d of crude by rail, truck, and barge in 2013, a 45% increase from 2012. Total refinery receipts of crude oil were around 15.2mn b/d, with more than half of that crude oil arriving by pipeline. The Gulf Coast (PADD3) region accounts for most US refinery receipts by rail, truck, and barge. PADD 3, where rail, truck, and barge receipts nearly doubled in 2012, is heavily dependent on rail and truck to move crude production out of the Eagle Ford and Permian basins to refineries in the area until new pipelines are built.

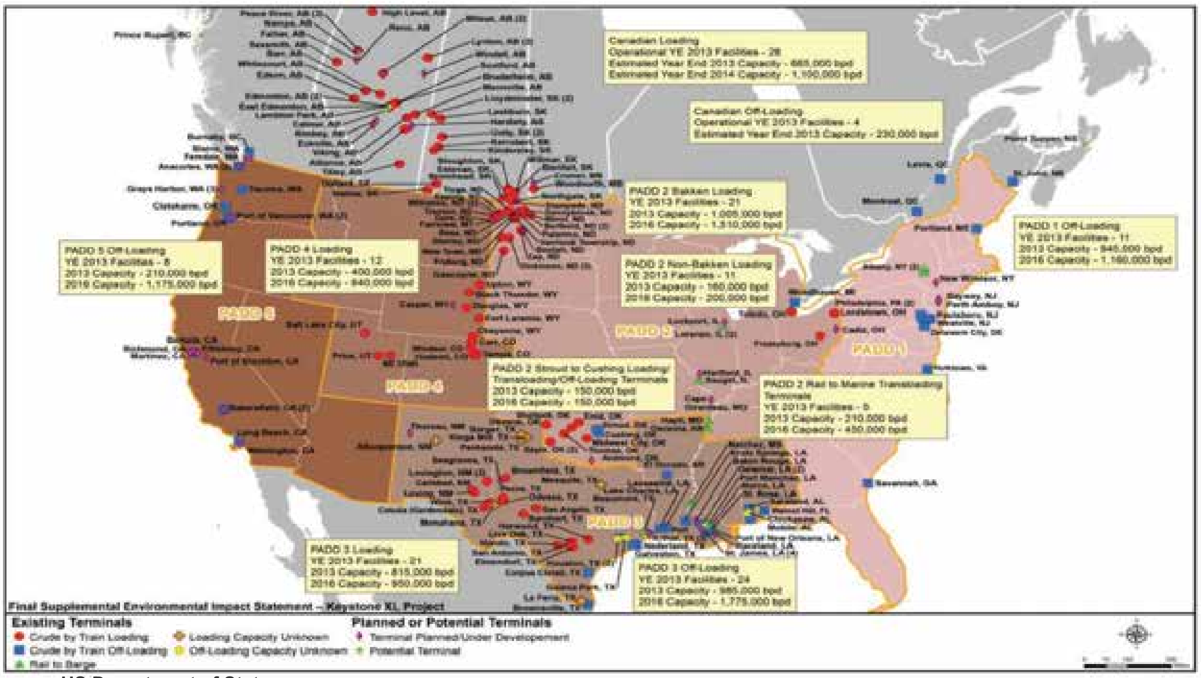
Crude transportation costs

From	To	Mode	Cost ($/bbl)
Alberta	Cushing	Rail	13
Alberta	US Gulf Coast	Rail	15
Alberta	US West Coast	Rail	10
Alberta	US East Coast	Rail	16
Alberta	US Gulf Coast	Pipeline	10
Alberta	Cushing	Pipeline	6
Cushing	US Gulf Coast	Pipeline	5-6
Cushing	US Gulf Coast	Truck	20
Cushing	US Gulf Coast	Rail	7-11
North Dakota	East Coast	Rail	16
North Dakota	Gulf Coast	Rail	15
North Dakota	West Coast	Rail	9.75
North Dakota	Gulf Coast	Pipeline	8-10
West Africa	US East Coast	Ship	1.5-2.2
NWE	US East Coast	Ship	1.15-2
Arabian Gulf	US Gulf Coast	Ship	1.3-3
US Gulf Coast	**Canada East Coast**	**Ship (Foreign vessel)**	**2**
US Gulf Coast	**Canada East Coast**	**Ship (US vessel)**	**5-6**

Sources: Natixis, RBN Energy

The cost of pipeline transportation between some parts of US and Canada is substantially lower than that of crude-by-rail. For example, Alberta to Gulf Coast by pipeline costs $10/bbl, whilst the same distance by rail costs more than $15/bbl. In theory, where the available pipeline capacity remains inadequate relative to the demand for crude transportation, regional oil

US crude-by-rail infrastructure



Sources: US Department of State

price spreads will continue to be heavily influenced by the cost of delivering crude-by-rail. For example, WCS-Maya spread of $13/bbl is close to the transportation costs of crude-by-rail and will continue to be influenced by that until sufficient pipeline capacity is built. But this is not the case for the light crude differentials which are continuously evolving. Drawdowns in Cushing tend to support WTI prices even though it leads to a build-up in crude stocks in PADD3, subsequently putting pressure on LLS.

Congestion Points

As Cushing and Jones Creek terminal becomes less congested, new choke points have appeared:

- **Hardisty:** The northern leg of the Keystone pipeline has not yet received approval and the Alberta Clipper pipeline project has been delayed. The Enbridge Mainline System from Hardisty to Superior has been hamstrung by limited space in recent years as oil-sands production raced ahead of pipeline capacity and alternative export projects, such as rival TransCanada's Keystone XL pipeline, ran into hurdles. Until the expansion of Enbridge mainline/Alberta Clipper, we could see Hardisty becoming a choke point. Alberta Clipper's expansion has been pushed from mid-2014 to July 2015.

- **Midland Texas:** With production rising in the Permian basin, areas around Midland, Crane and Colorado City are likely to act as choke points, at least until Bridgetex pipeline comes online in 2014Q3 from Colorado City.

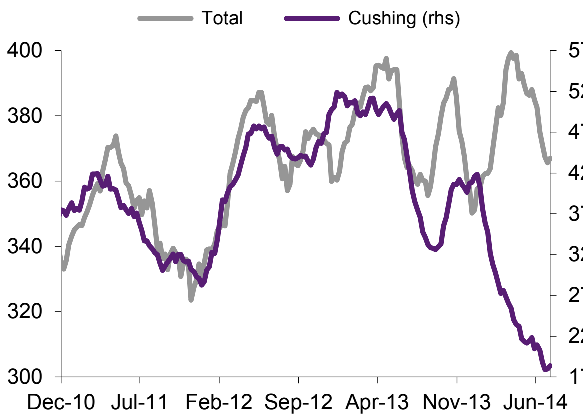
- **Gulf Coast:** With increased supply reaching the Gulf Coast from Cushing due to expansion of the Seaway pipeline and start-up of Gulf Coast pipeline, crude inventories in the Gulf Coast region have reached historical highs. The problem is exacerbated during the seasonal maintenance months, as seen in March-April this year, and this situation could worsen further with the opening of new pipelines to the Gulf Coast. Large volumes flowing into the Gulf Coast could also lead to oil backing up at Cushing.

- **Guernsey:** Another choke point is PADD4, where increased volumes of Canadian oil and North Dakota oil is arriving at Guernsey. Take-away capacity is limited until Pony Express starts in the second half of 2014.

US Crude Stocks

US crude stocks reached a historical peak of 399.4mn bbl in April 2014, their highest ever. Previous record highs were in May 2013 (398mn bbl) and July 1990 (392mn bbl). Gulf Coast stocks measured 216mn bbl in May 2014 (65% of available shell capacity in the Gulf Coast as reported by EIA in March 2014). Total shell capacity in the Gulf Coast, including refinery tankage, is around 330mn bbl.

US crude oil stocks (mn bbl)



Sources: Natixis, Bloomberg

In contrast to Gulf Coast stockpiles, Cushing stocks are continuing to drop towards their operational minimum (~12mn bbl). This is due to total incoming capacity into Cushing being around 2.02mn b/d against total outgoing capacity of 2.18mn b/d.

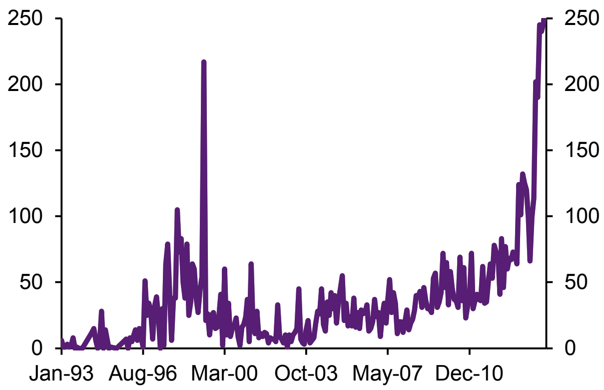
Imports vs Exports

The impact of rising crude production in the US has been seen in declining crude oil imports, especially the lighter grades in PADD1 and PADD3. Light crude imports with API greater than 35° have declined significantly. US light crude imports from Algeria, Angola and Nigeria have declined. As additional North American crude reaches the various PADD regions, either via pipelines or railcars, so refineries are switching from expensive overseas crude to cheaper domestic crude. Even where US refineries are complex (designed for medium-heavy crude from the Gulf of Mexico), at a given spread between US light crude and imported heavy crude, they will prefer to take the cheaper light crude and mix it with less expensive heavy grades or make necessary adjustments to increase their intake of lighter crude.

With the change in complexity of refineries, it is evident that the US is importing more medium-heavy crude, with most of it emanating from Canada and Saudi Arabia. Heavy crude imports from Mexico, Colombia and Venezuela have decreased.

Oil producers are looking at different ways of exporting US oil to benefit from high international oil prices. US crude producers already have the ability to export crude to the Canadian market. However, Canadian producers cannot re-export this crude, hence the market is limited to refinery inputs on the East Coast of Canada. Volumes have nevertheless increased significantly in recent months. Refining capacity in eastern Canada and Ontario was 1.37mn b/d in 2013, according to National Energy Board of Canada. Exports to Canada have risen from an average of 46,000b/d in 2011 to highs of 245,000b/d in 2014 so far.

US crude exports to Canada (000 b/d)



Sources: Natixis, EIA

To destinations outside North America, only exports of non-US crude are allowed. US oil companies can already export foreign crude as long as it is not commingled with the domestic grade. In the last six months, US authorities have approved 52 crude oil re-export licences to destinations other than Canada. This includes 14 licences for re-exports to European countries. Enbridge has announced plans to export Canadian crude via US ports while Valero has obtained a licence to export light Canadian crude from the Gulf Coast to Canada or the UK. Releases of foreign crude from the SPR have also become a realistic possibility. The US government released 5mn bbl of SPR crude in the first half of 2014 to test its oil infrastructure.

Splitter refineries to bypass crude oil export ban

Splitter refineries refine crude into a product that just escapes the US ban on crude exports, taking very light oil one step closer to becoming an oil product such as gasoline or diesel. The aim is to export this light product, which has a very low processing cost. The first splitter refinery is being built by Kinder Morgan Energy Partners and should start to process crude for BP by summer of 2014 with a 100,000b/d capacity. The plant will cost $370mn (80 to 90% cheaper than a full refinery). Refiners such as Valero and other pipeline operators including Magellan Midstream Partners plan to build "splitters," and the total capacity could reach more than 400,000b/d by 2018.

Stabilisers to bypass crude oil export ban

The US Department of Commerce is allowing oil companies to export even lightly processed condensates. This means oil companies can produce exportable condensates extracted from oilfields if they have been passed through a stabilisation unit (de-butaniser or de-pentaniser) where light gases or other volatile hydrocarbons are removed. This process employs significantly lower energy inputs than would be required for a simple distillation unit. US condensate exports have been a grey area because the US already allows exports of plant condensates separated from natural gas using a gas processing plant but not lease condensates which are separated from natural gas at the well-head at surface temperature and pressure. Allowing the export of processed condensates is therefore not new, but the new permission clearly suggests that the US authorities will allow oil producers greater freedom to export lightly processed crude. US lease condensate production, which is defined as crude oil by EIA, is close to 1.2mn b/d according to RBN energy, with most of it being produced in Eagle Ford and Permian basin. According to Wood Mackenzie, total ultra-light crude production is around 750,000b/d, while total stabiliser capacity is in the range of 200-500,000b/d in the Gulf Coast (mostly in Eagle Ford), which is where we would expect the US to start exporting this lightly-processed crude from initially.

While the US oil export ban will remain very much in place, these developments clearly show how the US oil industry, with the tacit approval of US authorities, is becoming more easily able to circumvent the letter of the law in exporting "lightly-processed" crude. The potential export of US crude into the global markets could add to downward pressure on Brent prices, helping to narrow the spread between US crude blends and Brent. Once they begin to come on-line, splitter refineries will add to this growing volume of US crude reaching the global market. We believe allowing condensate exports in this way will enable the US government to assess the potential impact of US crude exports on oil product prices. If it helps to bring international oil product prices down, then it could set a good precedent for the US government to argue its case with Congress for a wider relaxation of US export restrictions.

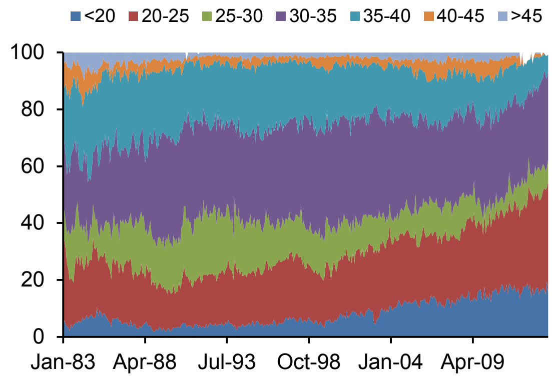
Developments in the US refining industry

In an effort to reduce the US dependence on imports of light crude, as well as to improve margins, US refineries were historically configured to process those heavier crudes which were typically available in the Gulf of Mexico. Over the last decade, this led to an increase in US refiners' complexity, particularly on the Gulf Coast.

With the arrival of light, sweet US crude from tight oil formations, as well as heavy sour crude from Canada, US refineries on the Gulf Coast have had to adjust their operations to take a blend of both heavy sour and light sweet crude which optimises profitability given their relatively high complexity.

This has meant increased imports from heavy oil producers such as Canada and Saudi Arabia, but declining imports from light, sweet producers such as Nigeria, Angola and Algeria. In terms of the average slate of US crude, overall crude API has increased by 0.46° since 2009, while sulphur content has increased by 0.03% pts over the same period. Despite their potential attraction as a complement to light sweet US crude, imports of oil from Venezuela have fallen since their 2005 peak as US oil companies' assets have dwindled in the country.

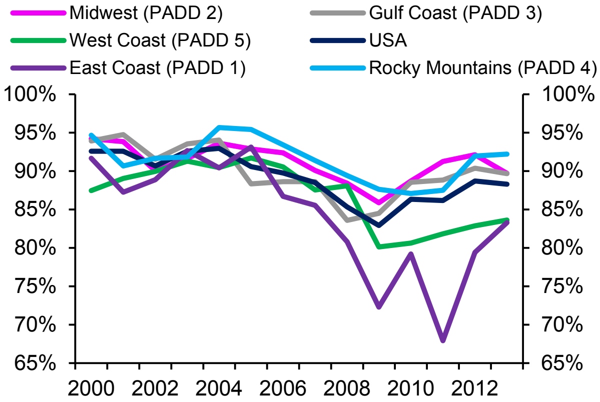
Percentage of US crude oil imports by API gravity



Sources: Natixis, EIA

According to the EIA, total US refining capacity increased by 421,000b/d from January 2012 to January 2013 to reach 17.82mn b/d. This increase was mainly due to Motiva Enterprises' expansion in the Gulf Coast (PADD3) and the restart of the Trainer, Pennsylvania refinery formerly owned by Phillips 66 and now owned by Monroe Energy, a subsidiary of Delta Airlines. Motiva's Port Arthur refinery was expanded by 325,000b/d in 2012 (total capacity after expansion: 600,000b/d). However due to technical glitches on its new crude distillation unit (called VPS-5), the refinery only started to operate at full capacity in January 2013.

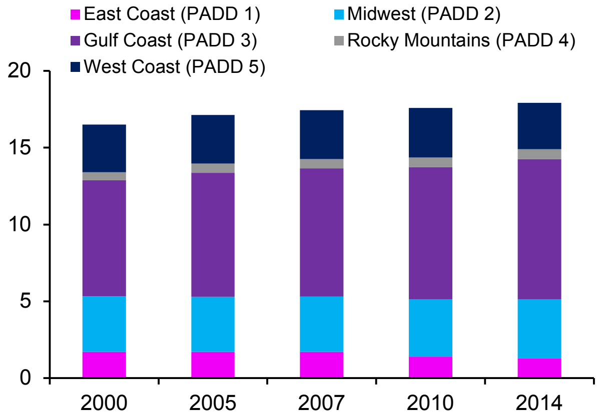
Refining utilisation rate by PADD



Sources: Natixis, EIA

Between January 2013 and January 2014, US operable refining capacity increased by 105,000b/d, according to the EIA. A part of the increase was due to the completion of the Whiting refinery modernisation project in Indiana. The modernized 413,000b/d refinery now has the capability to process up to 85% heavy crude against 20% before the project began, with a new 102,000b/d Coker that started in mid-November last year. The spread between WTI and WCS front month contracts has averaged $19.3/bbl in the first half of 2014 against $20.6/bbl for the same period last year, with the narrowing of spreads facilitated by higher US capacity to process Canadian crude. Canadian crude imports into the US increased by 1.5% yoy during 2014Q1.

Operable crude distillation capacity (mn b/d)



Sources: Natixis, EIA

Average US refinery utilisation rates decreased by 0.4% pts yoy in 2013. So far this year (first half of 2014), utilisation rates are up 2.4% pts yoy. On top of the increase in operable capacity, this clearly suggests strong domestic demand for oil products and demand for oil exports.

Utilisation rates in PADD1 in particular have recovered significantly since 2011, rising from lows of 67.9% in 2011 to highs of 83.3% in 2013. Utilisation rates in PADD1 declined between 2005 and 2009 due to lower demand for gasoline due to CAFE-led demand reduction and then from 2009 onwards due to lower passenger miles travelled on top of further CAFE-inspired gains in fuel efficiency. This difficult situation was exacerbated further by high international crude prices which the PADD1 refiners were reliant upon since they were unable to gain access to cheaper domestic crude available elsewhere in the US. As a result, PADD1 refining capacity declined by 394,000b/d between 2007 and 2013 to 1.079mn b/d. With the improved transport logistics that now enable PADD1 refiners to take cheap mid-continent crude, utilisation rates have risen alongside the improvement in PADD1 refining margins.

West coast refiners have suffered from a similar problem, as declining output of Alaskan North-Slope crude pushed prices higher, reducing refining margins in this part of the country. As new transportation links bring mid-continent crude to the west coast, so refining margins should improve, pushing utilisation rates higher once more.

There has also been significant change in utilisation rates in the other PADD regions in the US. Thanks to increased oil product exports since 2010, PADD2, PADD3, PADD4 and PADD5 utilisation rates have gone up by 3.8% pts, 5.2% pts, 4.6% pts

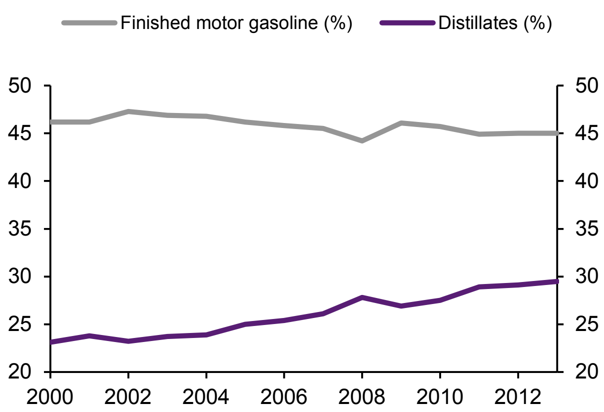
and 3.5% pts respectively. Positive growth in domestic demand since 2013 will further support an increase in refinery utilisation in the US going forward.

Crude movements between PADD regions have also increased. Crude movements between PADD2 to PADD3 have gone up from an annual average of 67,000b/d in 2009 to an average of 471,000b/d in 2013 by tanker, pipeline and barges. Due to lack of pipelines between PADD2 and PADD1, crude movements between the two regions are mainly achieved via rail. Crude movements by pipeline, barges and tankers between PADD3 and PADD1 have increased by close to 300% (+24,700b/d, average) between 2008 and 2013.

Refinery Product Yields

Product yields have changed significantly since 2000 due to developments in demand structure, regulations and changes in refinery complexity in the US. Gasoline demand has been negatively impacted by stricter emission requirements, as well as the financial crisis, which led to a fall in gasoline demand. At the same time US refiners changed their refinery complexity to process more heavy crude which yielded higher distillates. They have increased their capacity of hydrocracking to increase diesel yields, as well as thermal cracking and desulphurisation to comply with stringent low sulphur norms. Distillates yields increased from 23.7% to 29.5% between 2003 and 2013 due to the increasing complexity of refineries.

US refinery yields (%)



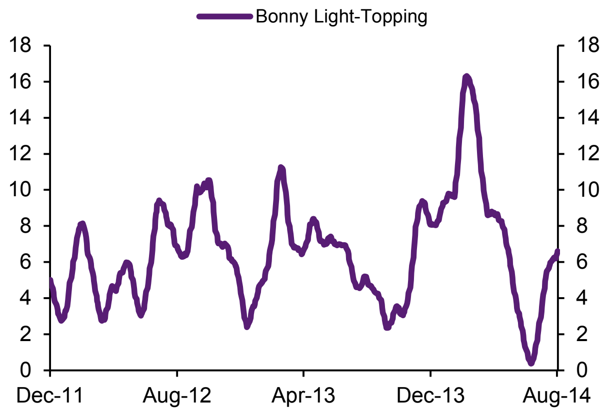
Sources: Natixis, EIA

In contrast, refineries have reduced catalytic cracking. Gasoline yields dropped from 47% to 44.2% between 2003 and 2008, before stabilising thereafter. Residual fuel yields also decreased, falling from 4.2% to 2.9% between 2003 and 2013.

Refining Economics

Refining margins in the PADD1 (Bonny Light), PADD2 (WTI) and PADD3 (WTI) regions have averaged around $5.1/bbl, $15/bbl and $13.3/bbl in 2013 respectively.

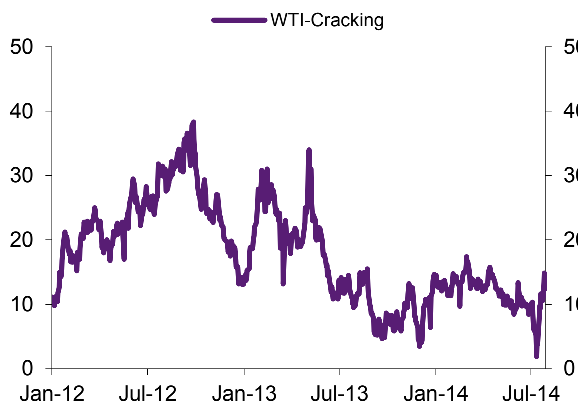
PADD1 refining margins ($/bbl)



Sources: Natixis, Reuters

Note: Excludes certain costs

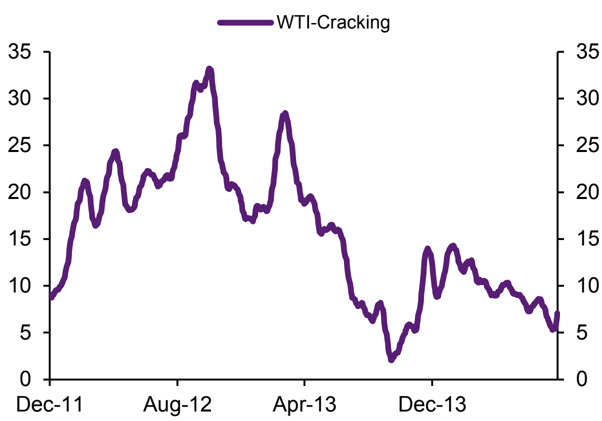
PADD2 refining margins ($/bbl)



Sources: Natixis, Bloomberg

Note: Excludes certain costs

PADD3 refining margins ($/bbl)



Sources: Natixis, Reuters

Note: Excludes certain costs

Costs of transportation from the mid-continent to other US regions remain an important factor helping to keep US crude prices below international benchmark prices. The cost of transportation for refineries in the Gulf Coast has declined over the past year as they have increasingly had the option of taking crude by pipeline instead of rail. This is still not the case for East Coast refiners, which are far more reliant on rail transport. PADD1 refiners are nevertheless able to benefit from cheap domestic crude, especially since refineries on the East Coast are less complex and therefore able to run a higher proportion of light crude.

Another key factor that is helping to maintain the healthy discount between US and international oil prices is the long-standing ban on exports of US crude. With oil product prices largely determined by international benchmarks, the on-going US crude oil discount to Brent has therefore helped US refineries to maintain high margins.

As far as cracks are concerned, gasoline cracks have increased yoy since 2011, initially due to low domestic crude prices and in later years due to strong demand and the RIN- related premium. In 2013, gasoline's price differential vs WTI increased by $4.3/bbl and so far this year it is up by a further $0.5/bbl. Heating oil's (now ULSD) price differential with WTI has also remained wide, nearing $29.54/bbl in 2013 and averaging above $25/bbl so far in 2014. 321 crack spreads for WTI in NY harbour are up significantly, rising from lows of close to $10/bbl in 2010 to highs of $32/bbl in 2012 and $22.9/bbl in 2013. For 2014 so far, it is averaging $19.7/bbl.

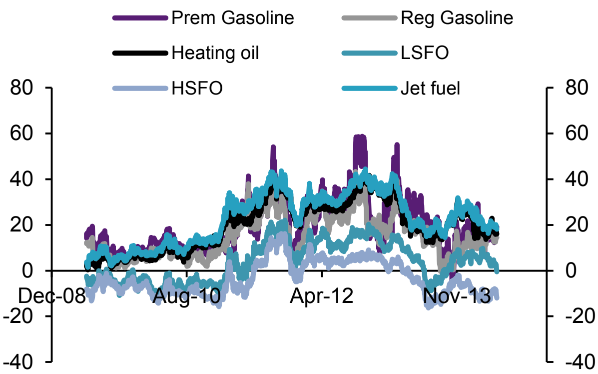
Unlike last year's spike in price of RINs that cost independent refiners at least $1.35bn, the Obama government has proposed a relaxation of the RINs mandate for 2014 for corn-based ethanol from 14.4bn gallons to 13bn gallons, thereby acknowledging the technical difficulty in achieving the mandate vs blend wall. Most of this was passed on to consumers through higher gasoline prices. The costs of meeting environmental regulations however are continuously rising, even though refineries have already undertaken substantial investment in upgrading their facilities to produce oil products that meet sulphur and other emission requirements. The EPA is now looking at releasing a new draft rule to crack down on oil pollution from oil refineries. More refineries could turn to using natural gas as a fuel in order to reduce emissions and costs. The EPA has also extended the timeline to meet the 2013 mandate of 13.8bn gallons of corn-based ethanol to 30th September 2014 for obligated parties.

Product Spreads

Refineries in the Gulf Coast have benefitted from high spreads between top of the barrel oil products and suppressed crude prices. The improving global economy has further helped increase international gasoline and heating oil prices.

Heating oil vs gasoline spreads are extremely seasonal. Refiners with higher distillates yields would have benefited from the severe 2014 winter-related tightness in heating oil demand. They could continue to benefit due to high demand for distillates from outside the US and shift away from high sulphur residual oil to low sulphur distillates.

USGC spreads vs WTI ($/bbl)



Sources: Natixis, Bloomberg

Refinery Shutdowns and Re-openings

Flint Hills Resources shut its Alaska refinery in May 2014 because of the rise in crude prices in the region. The price of Alaskan North Slope increased by 36% between 2010 and 2013 due to a drop in oil output in the region. In addition, environmental problems have added costs for cleaning up soil and groundwater pollution. The refinery has an 85,000b/d capacity, with 60% of its output going to aviation fuel.

Over the past five years, a number of East Coast refineries either shut down or scaled back operations. Around 426,000b/d of operable capacity was taken away between 2009 and 2014: Hess and PDVSA's Hovensa refinery on St Croix, Hess' 70,000b/d FCC plant in Port Reading (New Jersey), Sunoco's 140,000b/d Eagle Point refinery in Westville (New Jersey), and Western Refining's 128,000b/d Yorktown refinery (Virginia), all ceased operations and most have since been converted into storage terminals.

At the same time, Sunoco's Philadelphia, Marcus Hook and ConocoPhillips' Trainer plants went offline temporarily, resulting in the loss of 50% of East Coast refining capacity (as of August 2011). However, Philadelphia Energy Solutions now runs the 330,000b/d Philadelphia refinery while a subsidiary of Delta Airlines runs the 185,000b/d Trainer refinery, having bought it in June 2012 to recalibrate the plant to produce more jet fuel. Trainer also supplies refined products to Phillips66 and BP. The 175,000b/d Marcus Hook refinery was idled at the end of 2011 and now serves as a Sunoco Logistics tank farm storing gasoline and mid-distillates. These refineries are gradually returning to full capacity, supported by increased domestic crude availability via rail on the East Coast.

Capex

Capital spending by US refiners increased only marginally in 2013. In part, this reflected the substantial investment by the industry as a whole in new transportation capacity. In addition, refiners suffered a modest decline in margins for those situated outside PADD2. However, low US oil prices and solid demand for US oil product exports are still supporting US refining and marketing expansions, especially as transport infrastructure catches up with the expansion in crude supply.

Total light crude processing capacity additions and expansions expected in 2014 are around 196,000b/d, up from the 115,000b/d addition in 2013. Refiners have reduced spending on hydrocracking investments and diverted their spending to light crude processing. Calumet and MDU resources are constructing a new refinery with a capacity of 20,000b/d in North Dakota expected to come on-line by the end of 2014, which will process Bakken oil. Refiners such as Valero will add topping units at their existing refineries in Texas by the end of 2015 which will increase their light crude processing capacity by approximately 200,000b/d. In addition to that, oil companies such as Kinder Morgan and Marathon are building splitter refineries in order to export the lightly processed crude.

In terms of refinery specifications, the overall trend has been an increase in all units in the last few years. In 2013, the volume of vacuum distillation, thermal cracking, catalytic cracking, hydrocracking, catalytic reforming and hydro treating increased by 250,000b/d, 114,000b/d, 56,800b/d, 201,000b/d, 116,000b/d and 294,000b/d respectively.

Impact of refineries on crude oil stocks

The increase in total operable refining capacity in PADD2 by over 100,000b/d since 2012 and restart of the Whiting refinery after upgrade has further exacerbated the decline in crude oil stocks at Cushing, as more oil is diverted to the refinery. Alongside increased crude-by-rail facilities and additional pipeline capacity which is taking more crude away from Cushing to other PADD regions, this has helped to reduce crude stocks at Cushing to just under 18mn bbl as of 1 August 2014.

Cushing is no longer a choke point, as the take-away capacity from Cushing has increased over the past year and as more crude is being delivered directly to the Gulf Coast from the source of production. Instead, crude oil stocks in PADD3 have risen significantly to reach a historic high of 215.7mn bbl. So even though the refining capacity in PADD3 is the highest in the US, the supply of light crude is significantly outpacing the requirements of what are typically complex refineries on the Gulf Coast. The Gulf Coast's total shell capacity is in the region of 240mn bbl, as per the March 2014 EIA report, on top of which there is an additional 90mn bbl refinery storage capacity.

2014 light crude refinery expansion

Company	Location	Capacity (000 b/d)	Investment type	Date
Alon	Big Spring	2	Refinery expansion	Mid-2014
Dakota Oil Processing	Trenton, ND	20	New refinery	End of 2014
Kinder Morgan	Galena Park, TX	100	Condensate splitter	Mid-2014
Marathon	Canton, OH	25	Condensate splitter	End of 2014
MDU/CLMT Dakota Prairie	Dickinson, ND	20	New refinery	End of 2014
Tesoro	Salt Lake City, UT	4	Refinery expansion	2014
Valero	McKee, TX	25	Refinery Expansion	2014

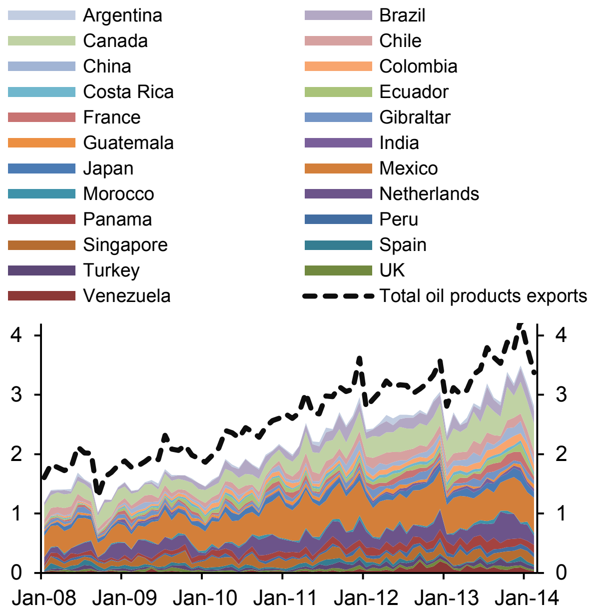
Sources: Natixis, ICF

The growth in total US refining capacity is easily being outpaced by the overall growth in oil output. Against yearly increases of around 1mn b/d in 2013 and 2014, refinery capacity will have increased by just 100,000b/d and 196,000b/d respectively. It is this mismatch which is leading to the increase in total crude oil stocks in the US, despite a reduction in imports over the last couple of years. The planned construction of splitter refineries and resultant increase in exports, including condensates and crude to Canada is unlikely to be enough to alleviate the problem of rising crude stocks in 2014, and may only offer marginal relief in 2015. Only a lifting of the US crude export ban will stop US crude stocks from rising in the near term.

Oil Product Exports

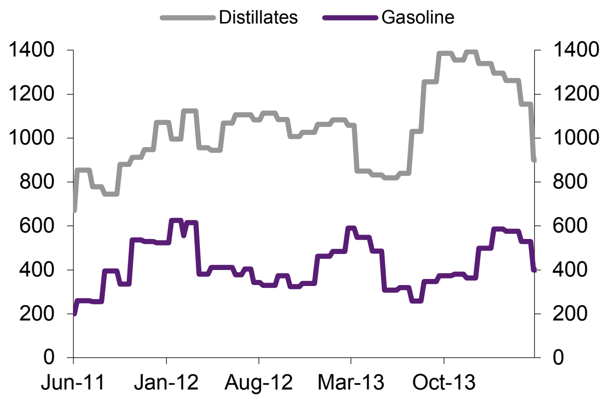
US exports of oil products have increased substantially in recent years, as refiners have maximised profits by exporting surplus oil products. Demand from Latin America, the Caribbean, Europe and Africa has helped increased US oil product exports for several reasons. Insufficient refining capacity in Latin America and Africa is one of the key reasons. But also low costs of refining in the US due to cheaper domestic crude inputs and use of natural gas in refineries has kept open the export arbitrage for a longer duration. Last year's increase in RIN prices exaggerated the rise in exports in 2013 as RINs are not required to export oil products. There is also no ban on exporting oil products, so refineries have benefited hugely from this.

US total product exports by destination (mn b/d)



Sources: Natixis, EIA

US oil product exports by product type (000 b/d)



Sources: Natixis, EIA

Circumventing the Jones Act

US East Coast gasoline imports surged to the highest level in 11 months in May 2014 amid speculation that increased blending at Caribbean sites, including Buckeye Partners' Bahamas terminal, boosted shipments. The region received 861,000b/d of gasoline in the week ended 9 May 2014, up 61% from the previous period and the highest level since 21 June 2013, according to the EIA. A March 6 decision by US Customs and Border Protection now allows gasoline components to be shipped from the Gulf Coast to the Bahamas, blended into finished gasoline and sent to the East Coast on foreign-flagged tankers. The decision effectively relaxed the Jones Act requirement that US-made fuel be shipped between domestic ports on US-flagged vessels.

This move will help reduce the import demand for gasoline from outside the US and could help push up refinery utilisation rates further in the USGC or elsewhere as they are able to send more domestic oil products to other PADD regions. We suspect something similar will occur in the case of splitter refineries, where splitter refineries on the Gulf Coast could make this cheap crude available to East Coast refiners.

Future of Refineries in the US

Faced with the unprecedented increase in North American light crude production, US refineries are expanding their light crude capacity just as Valero is doing. Even complex refineries are likely to increase their inputs of lighter crude as long as the spread between domestic light and imported heavy crude prices generates a higher overall margin on reduced throughput. But there is a technical limit to which complex refiners can use light crude in their refineries.

With economic recovery in the US helping to strengthen demand for oil products, US refiners are likely to benefit from this growth in demand. Adding to this scenario is the ailing refining market in Europe, continuous disruptions to the oil sector in North West Africa and limited refining capacity in Latin America, which is a gap US refiners are keen to fill. This positive scenario has been sustained by the on-going discount between US domestic crude and international crude prices. All of these factors are contributing to strong US refining margins, which are expected to remain in place over the near term.

In the medium term, we would expect margins to decline somewhat as spreads between WTI and Brent are expected to fall to around $5-6/bbl, if not less. Increased refining capacity in the Middle East is also likely to compete for product markets in EU and Africa, which could impact US refining margins.

US Demand for Oil and Oil Products

US GDP posted a sharp deceleration in the first quarter of 2014 from +3.5% in 2013Q4 to -2.1% qoq at an annualised rate. Nevertheless, economic prospects remain well oriented in the United States. Indeed, most of the Q1 drag came from a set of temporary factors: adverse weather conditions (low temperatures and blizzards) that disrupted the supply chain and hindered domestic spending, lower increases in inventories, and a slump in net exports.

The US economy rebounded strongly in Q2, registering 4% (qoq SAAR) growth as the labour market continued to recover. With monthly payrolls showing employment growth of 200,000 or more per month, unemployment dropped to 6.1% in June 2014. US manufacturing indices returned to their late-2013 highs, alongside a rise in service-sector activity. Despite some temporary signs of weakness in the US housing market, the outlook for economic growth in 2014H2 and 2015 appears positive.

We therefore expect growth, after the catch-up effect in Q2, to continue to gain momentum in 2014H2 and in 2015. Fading fiscal pressures should give households more leeway to consume, while reduced fiscal and economic uncertainty and higher expected demand could support corporate investment. Despite only a sluggish recovery in wages (due to significant slack in the employment market), the moderate on-going improvement in households' financial situation is likely to continue to support the housing market. The deterioration in affordability through higher interest rates and higher house prices will nevertheless put the real estate market dynamic on a slower trajectory (we are looking at a single digit growth rate this year vs double digits in 2012 and 2013).

All in all, we now expect real growth to reach 1.7% this year. Our forecast for 2015 anticipates growth strengthening to 2.7%. In this context, the Fed should continue gradually to phase out its asset purchases program in the coming meetings (a reduction of $10bn at each meeting) with the end of the QE expected in October. We expect the first hike in the Fed Funds rate to occur by mid-2015.

The strength in the US economy is clearly reflected in the growth in US oil demand which for a second consecutive year will be up by over 0.9% yoy in 2014, based on our analysis. In 2013, oil consumption grew by 1.7% yoy. In the table below, we have compared the growth in North American demand and supply for 2014 given by various sources. Although there is a difference in demand growth numbers for the US given by the different providers seen here, supply growth numbers more or less tell one story. US crude supply growth will outpace domestic demand growth by a factor greater than 10 in 2014.

YoY growth in US demand & supply (000b/d)

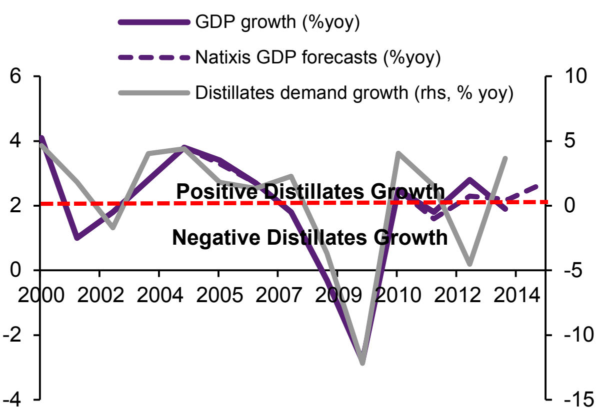
	Supply		Demand	
	2013/2014	2014/2015	2013/2014	2014/2015
EIA	1,350	1,070	10	120
IEA	1,200	740	50	40
OPEC	1,120	820	150	180

Sources: IEA, OPEC, EIA

Distillates

US distillates demand growth is strongly positively correlated to GDP growth. With US GDP expected to increase by 1.7% yoy and 2.7% yoy in 2014 and 2015, we can therefore expect relatively strong growth in US demand for distillates in 2014 and 2015. So far in the first half of 2014, US distillates demand has increased by 2.9% yoy. According to DOE data, annual distillates demand increased by 3.8% yoy in 2013, mainly driven by trucks demand, despite a drop in other key distillates consuming sectors such as residential heating.

US GDP growth vs distillates demand



Sources: Natixis, Bloomberg

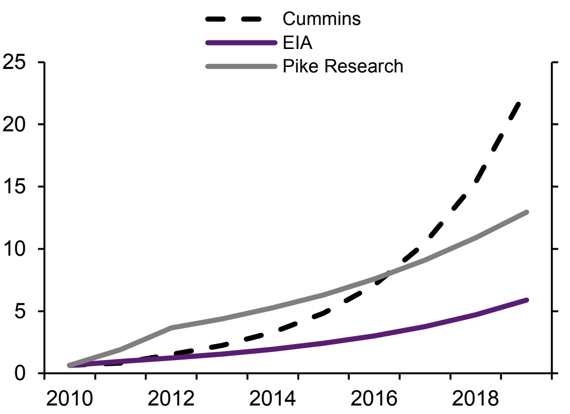
Heating oil demand increased by 11% yoy in 2013 to just over 233,690b/d due to severe winter weather, even though an increasing number of households moved to natural gas. Overall, some 6.9mn households rely on heating oil nationally. The number of overall household users, however, has declined from 8.7mn in 2006-2007, and the EIA projects a 3% decline for 2013-2014. By and large, the greatest demand for home heating oil is in the Northeast United States, where some 5.5mn households relied on it for primary space heating during the winter of 2012-2013, consuming 645.5 gallons per household on average. Distillates fuel imports increased by 14.7% yoy to 143,000b/d in 2013. So far in 2014, distillate fuel imports are up 38% yoy, according to US Department of Energy.

In 2014, we expect US heating oil demand to decline or remain unchanged. Nevertheless, the increased demand during the exceptionally cold weather at the beginning of the year should reduce the negative impact of the on-going heating oil to natural gas transition.

In the trucking industry, the growth of the US natural gas vehicle market has advanced more rapidly than refuelling station development. This growth in the natural gas fleet could help accelerate the development of a comprehensive natural gas delivery infrastructure in the future. The largest part of the natural gas fleet sales is emanating from light-duty vehicles, which is more than 50% of total NG fleet (trucks, buses and light vehicles) sales. Within the heavy-duty trucks sectors, CNG trucks are a larger component of NG fleet as CNG trucks are economical over shorter distances in particular. Sales of LNG heavy-duty class 7-8 trucks is expected to have gone up from 860 in 2010 to around 2,000 in 2012. According to a recent FC gas intelligence report, natural gas consumption by trucks and other vehicles was around 32bcf (~14,000b/d) in 2012. Hence diesel substitution by natural gas from the trucking industry is expected to remain low in absolute terms in the near-future.

Despite a drop in demand for heating oil in the residential sector and the slowly accelerating diesel to LNG/CNG switch in large trucks due to substitution effects (oil-to-natural gas), US demand for distillates is nevertheless expected to increase by over 2% yoy in 2014.

Total diesel fuel displacement by LNG in class 7-8 trucks (000b/d)



Sources: Natixis, EIA, Pike Research

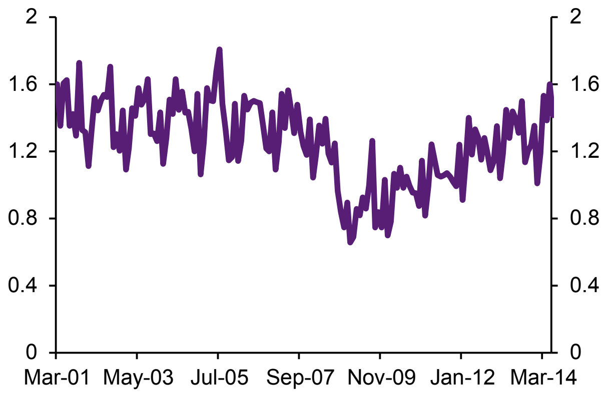
Note: Displacement of diesel demand by Category 7-8 Trucks shifting to natural gas as fuel. Other trucks and buses are not considered in the demand calculations above as heavy-duty trucks contribute 1.6mn b/d out of 2.35mn b/d diesel consumption today.

Gasoline

US gasoline miles travelled increased by 1.1% yoy in 2013. So far in 2014, passenger miles travelled for the first five months was higher by only 0.17% yoy. Tepid growth in 2014 can be explained by weather related weakness in gasoline demand at the beginning of the year. However, we expect a strong growth in US economy this year. With the improving US economy and car sales expected to grow above pre-recession levels, we can expect some positive growth in US demand for gasoline. This year is still on track to match or exceed 2007 vehicle sales volumes. US car manufacturers have offered incentives to customers to buy more cars in 2014Q1. Centre for Automotive Research (CAR) is expecting growth of more than 4.5% yoy in light vehicle sales in 2014, including passenger cars, trucks and light commercial vehicles. In contrast, the CAR suggests car sales will increase by only 0.6% yoy in 2015 and plateau thereafter. In 2013, US car sales were up 6.4% yoy and gasoline demand was up 1.4% yoy.

Gasoline demand in the US was up by 1.6% yoy in the first half of 2014. US gasoline demand is increasing as consumers are buying new cars and driving more. There is also an element of pent-up demand as the US economy progressively recovers from the effects of the financial crisis. This is being supported by improving economic data, in particular strong labour market data, as well as growth in US consumers' disposable income (up 0.4%mom in May). Average gasoline prices remain relatively unchanged over the first six months of 2014. Consumer demand for gasoline is price elastic, hence rising prices would typically act to restrain growth in consumption during an economic upswing. With the proposed ethanol blending for 2014 at 13bn gallons, lower than EPA's initial target of 14.4bn gallons, we should see higher consumption of gasoline.

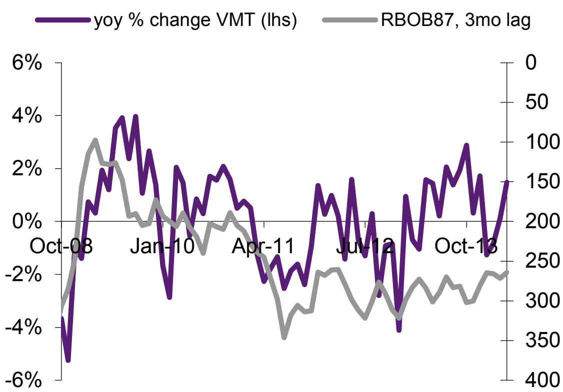
US monthly car sales (mn)



Sources: Natixis

Note: Includes all passenger cares, trucks (gasoline and diesel)

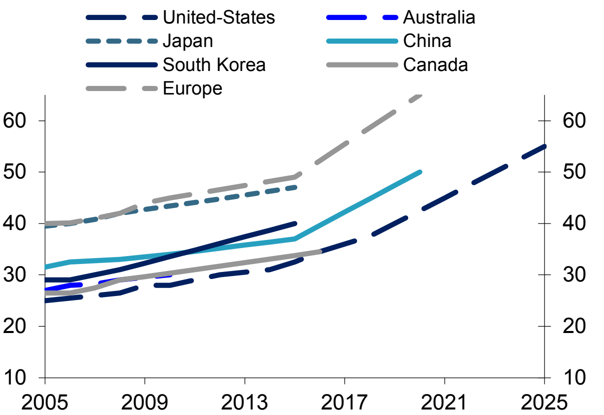
Annual US vehicle-distance travelled



Sources: Natixis, US FWHA, Bloomberg

CAFE standards, which require car manufacturers to achieve average fuel efficiency of 35.5mpg by 2016, are one of the key negative factors at play. US CAFE standard for passenger vehicles require an increase in fuel efficiency from 28mpg to 35.5mpg between 2012-2016, before rising more steeply to 56.2mpg by 2025. However, we believe that the negative impact of CAFE will, in the near-term, be more than offset by stronger growth in car sales and vehicle miles travelled as the US economy continues to recover from recession.

CAFE requirements, miles per gallon



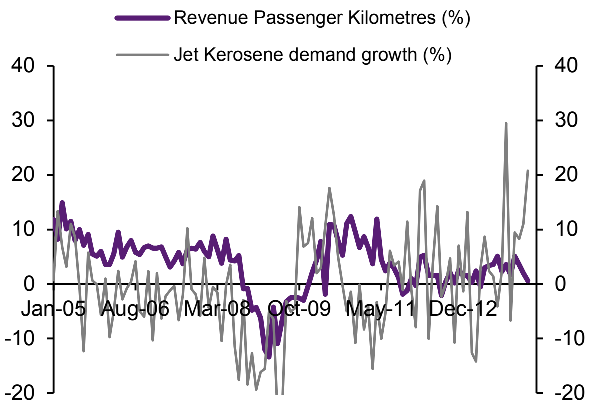
Sources: Natixis, ICCT

Note: mpg for all countries except US are normalised to CAFE test cycle

Jet Kerosene

Jet Kerosene demand is expected to be supported by an improvement in the US economy which in turn will help to boost US air miles travelled, both business and personal. So far, Jet Kerosene demand has increased by 2.9% yoy in 2014H1.

North America-passenger traffic vs jet kerosene demand growth



Sources: Natixis, IATA DOE, Bloomberg

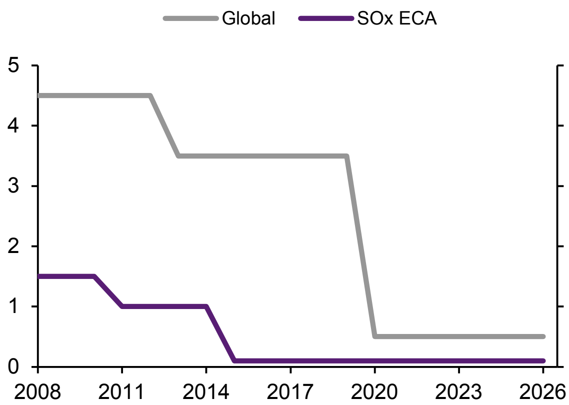
According to IATA, US air traffic expanded by 1.9% in 2013 (up from +0.8% in 2012), while capacity grew at the same rate, with the result that load factors were flat at 83.8%, the highest for any market. The improvement in demand, compared to 2012, reflects sustained increases in consumer confidence throughout the year as well as rising employment, particularly in recent months. US demand for Jet Kerosene increased by 1.6% yoy in 2013.

Residual Oil

Demand for residual oil fell by 20.2% yoy in the first half of 2014. Demand fell by 23% yoy in 2013 (for the whole year) to 280,000b/d.

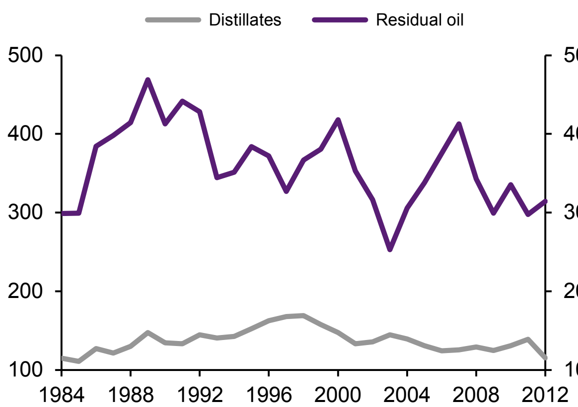
In 2015, the maximum sulphur content limit will fall to 0.1% in the SECA areas (North American coastal waters, Baltic and North Sea). Currently the maximum sulfur content is 1% (down from 1.5%), imposed since July 2010 inside designated areas. In the open ocean, the current limit is 3.5%, down from 4.5% prior to July 2012. This will be brought down to 0.5% in 2020.

Emission Control Areas - % sulfur tolerance



Sources: Natixis, Marpol

US vessel bunkering demand (000b/d)



Sources: Natixis, EIA

In 2012, total bunker fuel demand in the US was around 418,000b/d, of which the residual fuel component was 71% and distillates was 29%. Vessel bunkering residual fuel demand declined by 12.5% yoy in 2012 and we expect a significant decline in 2013-14. Bunker fuel is almost 75-80% of total residual fuel demand. We expect demand for residual fuel to decline further from 2015 onwards due to the new maritime regulations coming into place.

Other sectors, including industrial, commercial, power generation and oil companies, reduced their consumption of residual oil over the past decade due to environmental reasons as well as cheaper natural gas prices. Residual oil has high emissions. This shift towards cleaner fuel such as natural gas is expected to continue over the coming years.

YoY growth in US oil products demand in 2014 (000b/d)

	PIRA	ESAI	EIA
Gasoline	69.87	54	40
Jet Kerosene	31.49	6	20
Distillates	81.86	101	130
Residual	-11.20	-87	-60

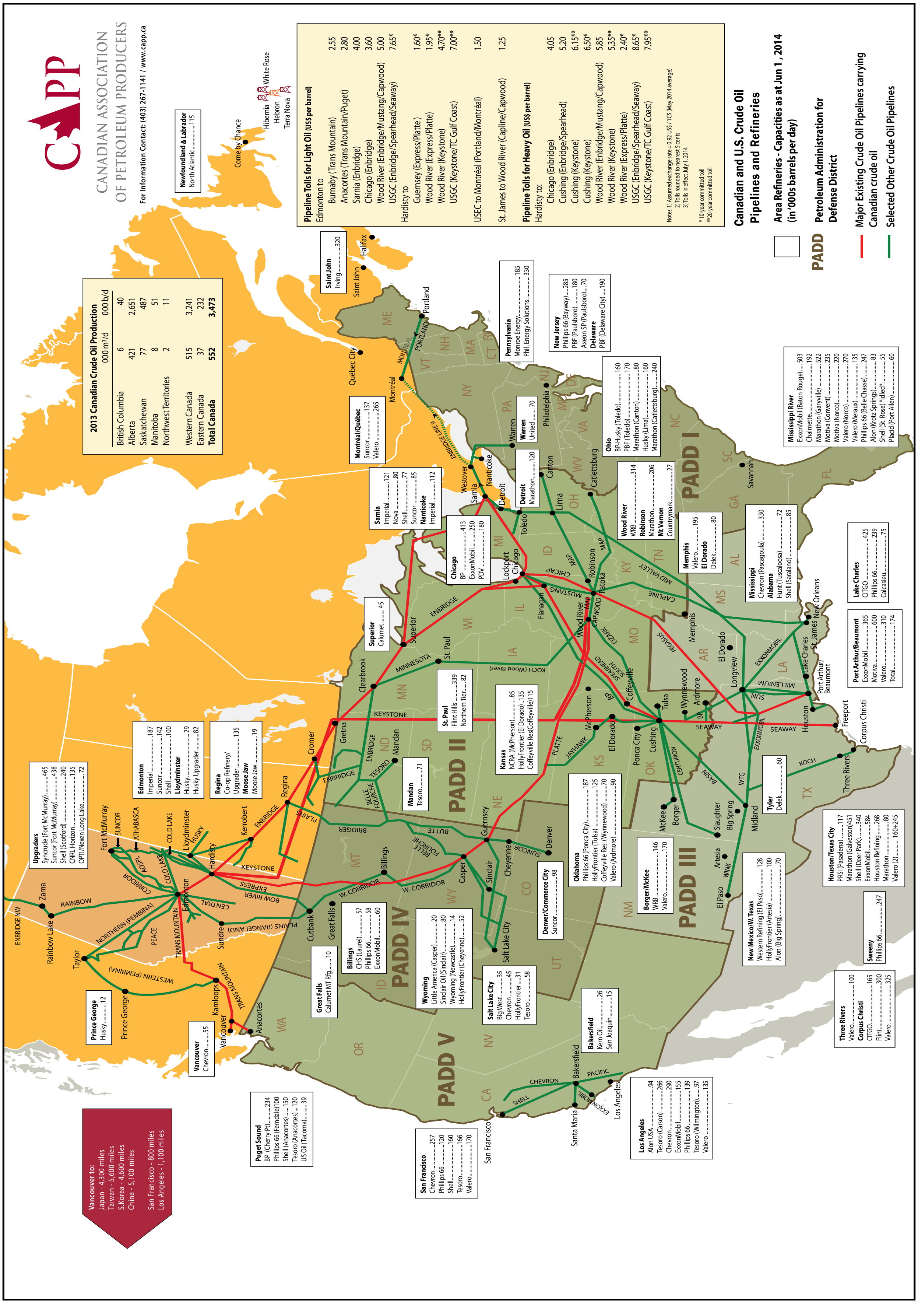
Sources: PIRA, ESAI, EIA

2014 US pipeline projects

	Startup	State	Capacity addition (000 b/d)
Seaway pipeline reversal	Mid 2014	In Service	450
Eagle Ford crude-condensate pipeline and condensate processing facility	Q1 2014	In Service	300
Longhorn Pipeline reversal	Mid-2014	In Service	50
Gardendale Gathering System expansion	H1 2014	Partially in service or nearing completion	115
Houma-to-Houston pipeline reversal	Early 2014	Partially in service or nearing completion	250
Mississippian Lime pipeline	Q1 2014	Partially in service or nearing completion	75
White Cliffs Pipeline	H1 2014	Partially in service or nearing completion	80
South Texas Crude Oil pipeline expansion	Q3 2014 and Q1 2015	Under construction or planned	35(2014) and 65(2015)
Western Oklahoma Extension	Q2 2014	Under construction or planned	75
Allegheny Access Pipeline	H1 2014	Under construction or planned	85
BridgeTex Pipeline	Jul-14	Under construction or planned	300
Flanagan South Pipeline	Mid-summer 2014	Under construction or planned	600
Galena Park to Houston Gulf Coast crude distribution	Mid-2014	Under construction or planned	140
Eaglebine Express	Mid-2014	Under construction or planned	60
Cline Shale Pipeline System	Q2 2014	Under construction or planned	75
Granite Wash Extension Pipeline	Q4 2014	Under construction or planned	70
Big Spring Gateway	Q4 2014	Under construction or planned	75
Total (2014)			2695

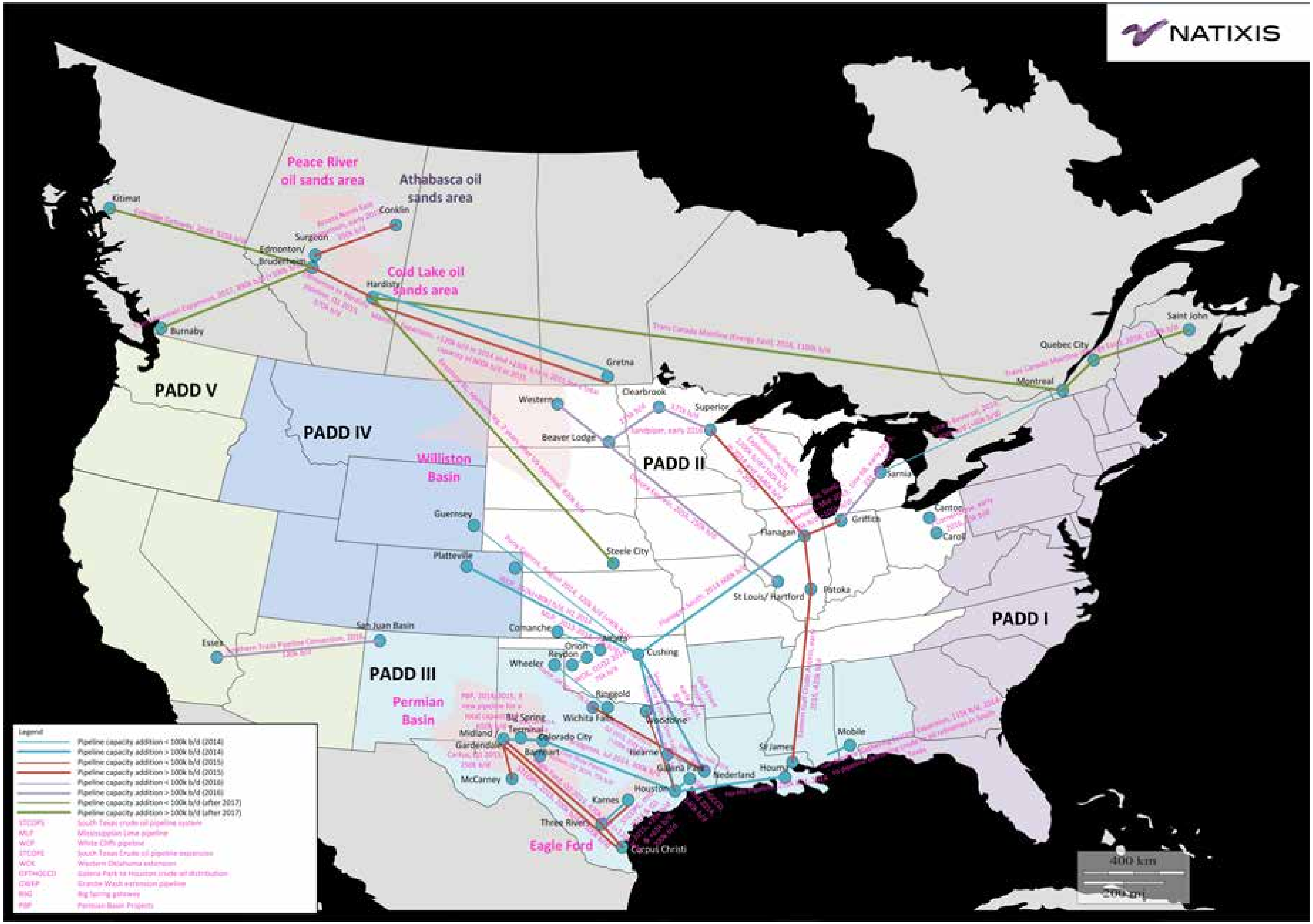
Sources: Natixis, Reuters

North American existing oil pipelines



Sources: CAPP

North American proposed oil pipelines



Sources: Natixis, D-Maps

Canada

The Canadian oil & gas industry plays an important role in North American energy dynamics. Canadian oil markets are influenced by several factors. On the supply side internally by Alberta's oil sands and externally by the expansion of shale oil in the US. The development of railroads and pipelines further impact oil prices in Canada as reflected in the wide differentials between Canadian crude prices and US as well as international oil prices. Here we look at recent developments in the Canadian oil market.

Oil Reserves

There are two major producing areas in Canada; the western Canada Sedimentary Basin (WCSB), which includes Alberta, Saskatchewan and parts of British Columbia and Manitoba, and offshore eastern Canada. Oil is also produced in modest volumes in Ontario and the Northwest Territories.

According to National Resources Canada, the country currently has 173bn bbl in proven crude reserves. According to BP it was 174.3bn bbl at the end of 2013. Around 97% of the reserves are unconventional, mainly found in Alberta's oil sands. The remaining 2-3% are conventional, offshore and tight oil reserves. East coast offshore conventional oil reserves are currently estimated at 1.5bn bbl, while Alberta's conventional and tight oil reserves are estimated at 1.7bn bbl

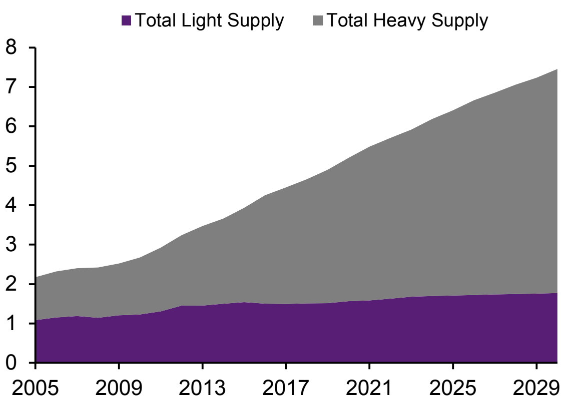
Oil Production

According to Canadian government statistics, Canadian oil production was around 3.54mn b/d in 2013. Western Canadian crude oil production averaged approximately 3.3mn b/d, representing a 6.5% increase over 2012. Production grew in a number of areas throughout the large western Canada Sedimentary Basin. Conventional crude oil production increased by 3.7% yoy, led by a 9.3% increase in light crude oil output in Alberta and Saskatchewan, where tight oil production has grown. Oil sands production also grew by 8.2% yoy, despite down-time at the Suncor and Syncrude upgraders in May 2013. In 2013, about 1.1mn b/d or 55% of the total bitumen produced in Canada was upgraded, including volumes of bitumen that were processed at the Suncor refinery in Edmonton.

There are four significant oil fields in eastern Canada, all off the coast of Newfoundland and Labrador: Hibernia, Terra Nova, White Rose and North Amethyst. Production from these fields increased by 15% in 2013, rising to nearly 240,000b/d, after being impacted by several operational issues in 2012. Around 47% of production was processed in domestic refineries, and over half was exported.

According to Canadian Association of Petroleum Producers (CAPP), Canadian oil output is expected to reach close to 3.7mn b/d in 2014 (+6-8% yoy), rising towards 5mn b/d by 2020 and 6.4mn b/d in 2030. This forecast is 300,000b/d below last year's expectations.

Canada crude oil supply (mn b/d)



Sources: Natixis, CAPP

The oil sands are expected to be the biggest contributors to Canada's oil production growth. Production from the Alberta-based deposits is expected to grow 2.5 times from current production of 1.9mn b/d to 4.8mn b/d by 2030. Conventional production, including condensate, is expected to grow modestly and contribute 1.5mn b/d.

The increase in production of bitumen will depend heavily on costs in the future.

Capex

Capital expenditures are expected to rise by 2.4% in Canada this year to C$80bn. Canadian oil companies once again plan to spend more on in situ mining and upgrading processes as well as transportation such as crude-by-rail. In 2013, high capex on infrastructure was a priority. The resultant increase in pipeline capacity will now help to facilitate capex on E&P which was budgeted to be up by 3.9% according to the OGJ.

Canada spending Plans 2012-2014

Million $ (Can.)	2014	2013	2012
Exploration-Production	**39401**	**37912**	**39733**
Drilling-exploration	26463	25463	26560
Production	12938	12449	13173
In situ, Mining, Upgrading	**33500**	**32000**	**27199**
Other	**7650**	**8789**	**5144**
Refining-Marketing	3100	2300	1920
Petrochemicals	1200	800	250
Crude & products pipeline	1500	3368	492
Natural gas pipeline	500	1141	1392
Other transportation	530	400	340
Miscellaneous	820	780	750
Total	**80551**	**78701**	**72076**

Sources: Natixis, OGJ

Costs

Similar to the US, Canadian breakeven costs are high. Oil sands breakevens are in the region of $100/bbl, while deep-sea offshore costs are around $110/bbl according to Chevron's CEO. The lifting and processing costs of new oil sands projects as per our last bi-annual report are between $58-70/bbl for surface mining, compared to $45-55/bbl for SAGD. Upgrading the heavy west Canadian crude into lighter, sweeter syncrude adds a further $20/bbl to the cost of production from oil sands. High labour costs in Alberta are putting further upward pressure on oil production costs. The new mining and upgrading projects therefore have a breakeven of close to $100/bbl. In situ production costs are also significantly dependent on natural gas prices as natural gas is used to generate steam to mobilise bitumen within in situ production.

According to National Energy Board of Canada, integrated mining and upgrading projects are estimated to cost in the order of $100,000 to $120,000 per barrel of daily capacity (in 2012 Canadian dollars) to build, requiring an oil price of US$80 to $100/bbl (in 2012 dollars) to make a new project economic.

Estimated initial capex and breakeven prices for new oil sands projects-2012

	Capex ($/bbl of capacity, C$2012)	Breakeven ($/bbl, US$2012)
Mining, extraction and upgrading	C$100,000-120,000	US$80-100
Stand-alone mining and extraction (no upgrading)	C$55,000-75000	US$70-100
Standalone upgrading	C$55,000-65,000	US$55-65
SAGD, Cyclic steam stimulation	C$25,000-45,000	US$50-80

Sources: National Energy Board, Canada

Crude Infrastructure and Transportation

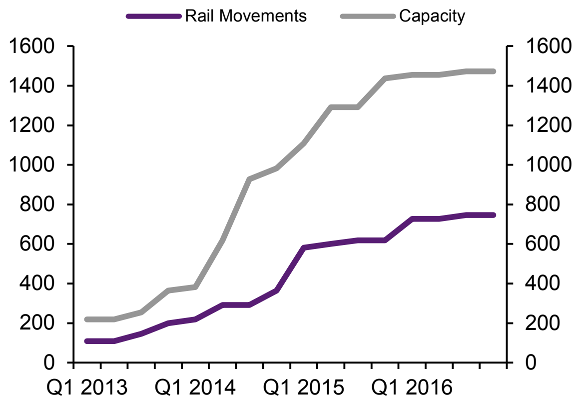
Crude-by-rail

Canada crude-by-rail volumes increased to 313,000b/d in December 2013 (+76,000b/d yoy). Oil transportation by rail is expected to more than double over the next 3 years to 700,000b/d.

Canadian National (CN) transported approximately 73,000 carloads of crude oil in 2013 across its North American network, more than double the previous year's carloads. It expects to double its crude oil carload volumes again by 2015.

The CAPP forecast suggests that rail-loading capacity will expand to more than 1mn b/d by the end of 2015. If several additional facilities go ahead, capacity could expand further to 1.4mn b/d.

Western Canada uploading capacity vs. rail movements (000 b/d)



Sources: Natixis, CAPP

For oil transportation, Canada's rail industry is evolving from a manifest system, in which trains might have to make multiple stops to deliver different products, to a unit system, in which trains go directly from the point of origin to the point

of destination. The number of Canadian rail tank car loadings of crude oil and petroleum products reached more than 17,000 carloads in January 2014.

The tighter regulations relating to crude-by-rail after a string of disasters in North America have led to upgrading of facilities in the US and Canada. Canada will phase out all the old legacy DOT-111 rail cars by May 2017. US regulators are expected to phase out DOT-111 tank cars in 3-5 years, following the deadly explosion in Quebec in 2013.

New pipelines in Canada

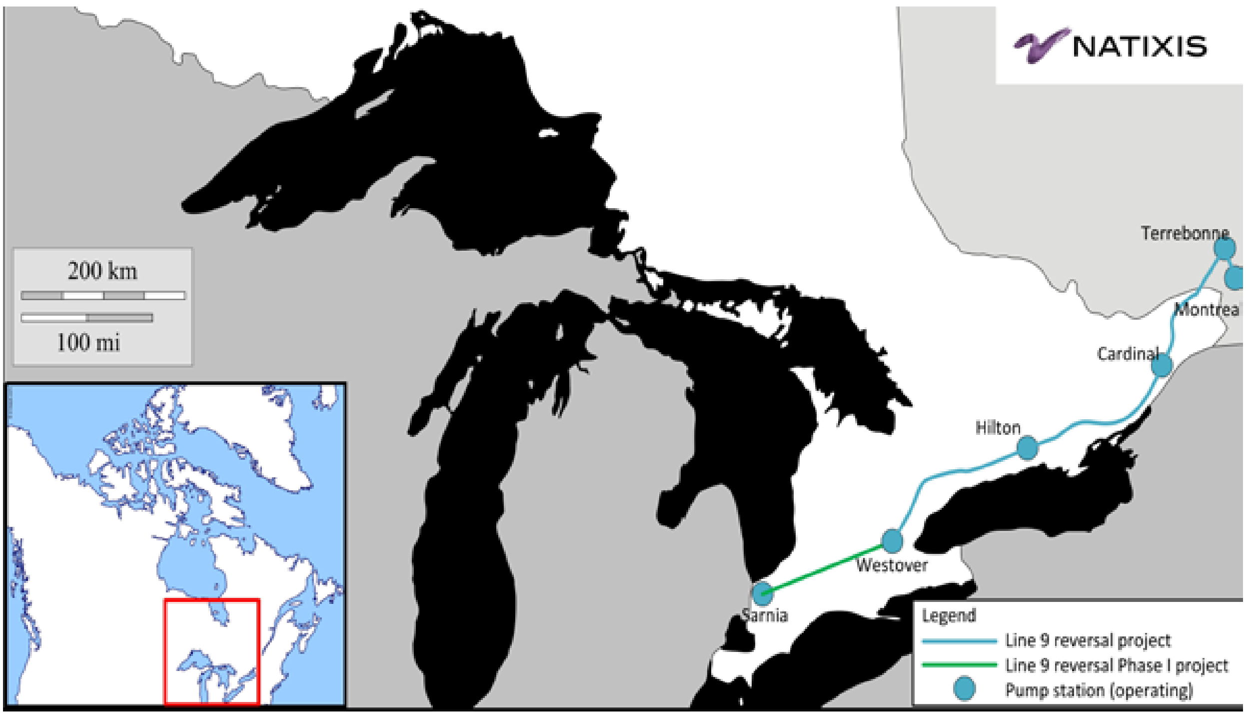
Oil supplies in western Canada from the oil sands and from new shale plays continue to increase, while four major pipeline projects — Keystone XL, the TransMountain expansion, Northern Gateway and Energy East — await regulatory approval and construction.

In 2014, few pipelines are scheduled to come online in Canada, unlike the US. Enbridge will be completing the reversal of Line 9 with a capacity of 300,000b/d (+60,000b/d) from Sarnia to Montreal (until recently it carried oil from Montreal to Sarnia) in 2014Q4. There have been several protests in an effort to stop this reversal by opponents who argue that the Line 9 plan puts communities at risk, threatens water supplies and could endanger vulnerable species in ecologically sensitive areas.

More capacity additions are expected between 2015-17, but most are embroiled in political debate and their target dates keep changing. Two expansion projects on Enbridge Energy Partners' Alberta Clipper pipeline will be delayed until July 2015. The Alberta Clipper, also known as Line 67, which now carries 450,000b/d from Hardisty, Alberta, to Superior, Wisconsin will be expanded to 800,000b/d by July 2015. Enbridge initially had plans to expand the pipeline by 120,000b/d in 2014, but got delayed due to the environmental review process. Access Pipeline Inc's North East Expansion project from Conklin (Northeastern Alberta) to Edmonton with 350,000b/d capacity is expected to be ready by 2015. TransCanada's Keystone XL pipeline (830,000b/d) is still in limbo, embroiled in a political tussle. In April 2014 President Obama mentioned that no decision will be made until mid-term elections that are due in November 2014. If the pipeline is approved in November 2014 (highly unlikely), it would only be ready by 2016-17.

The $7.9bn Northern Gateway pipeline project by Enbridge from Bruderheim (Alberta) to Kitimat (British Columbia) was approved in June 2014 subject to 209 environmental, technical and financial conditions. The pipeline is expected to be 1,177km long with capacity of 525,000b/d. Most of the crude will be exported to Asia. One of the two pipelines would bring a type of crude called diluted bitumen to the coast, the other would take condensate, used to dilute the crude, in the other direction. It will be ready in 2017-18.

TransCanada's Energy East pipeline project would convert parts of the under-utilized 3,000-kilometre gas pipeline from Alberta to Quebec to transportation of oil, and involve another 1,400 kilometres of new pipeline build from Quebec to New Brunswick. With the project gearing up to deliver up to 1.1mn



Sources: Natixis, D-Maps

b/d to refineries and export terminals in Quebec and New Brunswick in 2018, this would provide a substantial new market for Alberta and Saskatchewan's growing production.

The Trans Mountain expansion project is a proposal to expand the existing Trans Mountain pipeline system between Edmonton (Alberta) and Burnaby (British Columbia). The pipeline will include approximately 987km of new pipeline and reactivation of 193km of existing pipeline. The Westbridge marine terminal would also be expanded. New pipeline would be added between Edmonton and Hinton in Alberta, Hargreaves and Darfield in British Columbia and Black Pines and Burnaby in British Columbia. Trans Mountain plans to spend $5.4bn to construct the 1,150km pipeline with a capacity of 590,000b/d (+290,000b/d). It will begin construction in 2015/16 and is expected to go online in 2017.

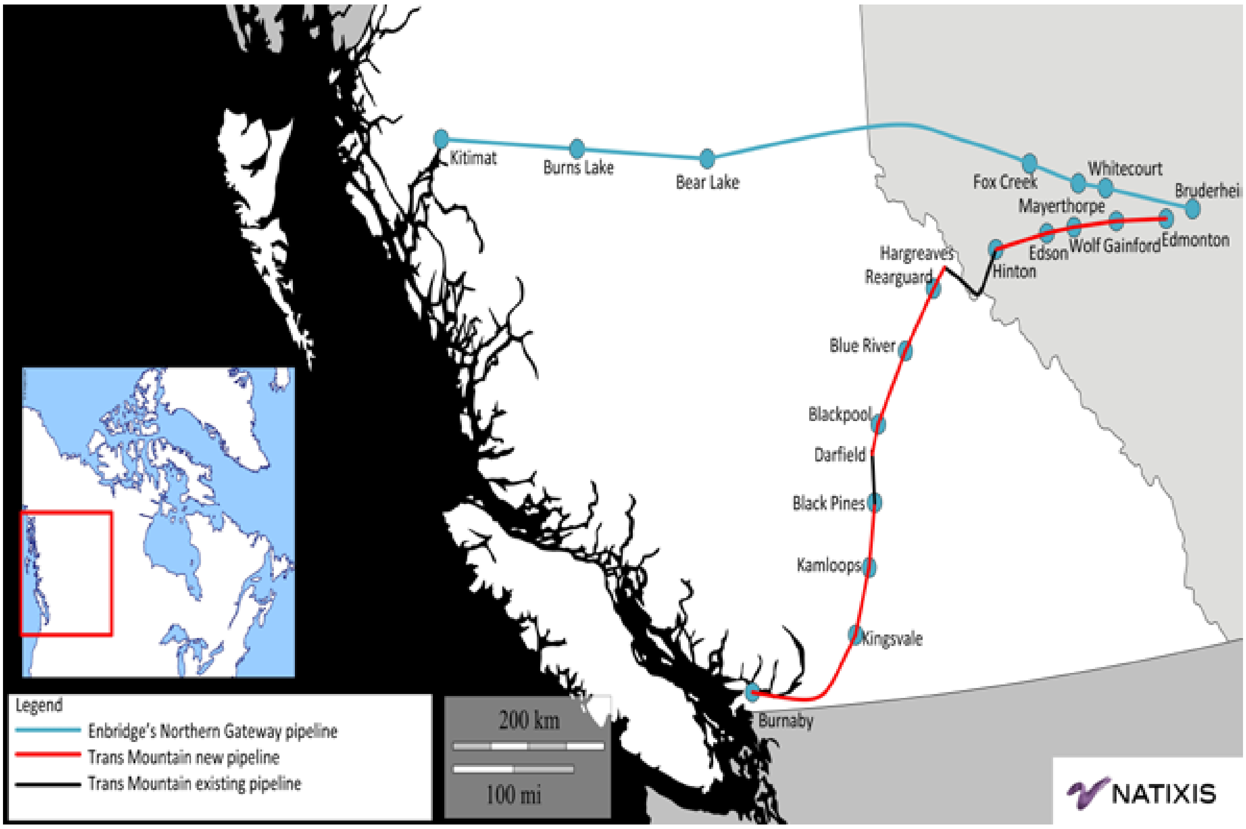
Crude Exports vs Imports

In 2013, over 70% of Canadian crude production was exported to the US, while just 2% was exported to overseas markets from terminals on the east and west coasts. Canadian crude exports in 2013 were 2.47-2.5mn b/d, up from 1.45mn b/d in 2011. US oil imports from Canada - unlike oil imports from other countries - continued to grow. US oil imports from Canada have increased from 16% of total US imports in 2005 to 32% in 2013.

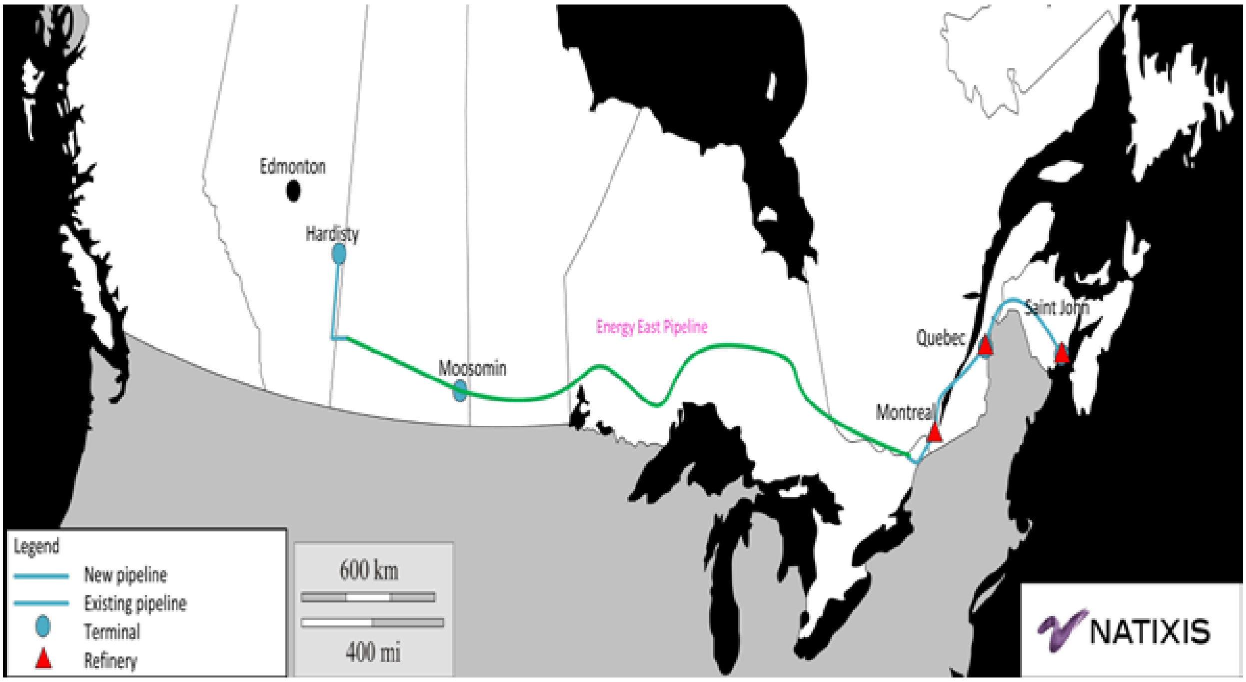
Canadian crude imports from the US have increased rapidly in recent months, reaching highs of 263,000b/d in April 2014, up from an average of 45,000b/d in 2011, almost a six fold increase. Canadian producers cannot re-export this crude, hence the market is limited to refinery inputs on the East Coast.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Northern Gateway Aboriginal and public consultation										
Filed the regulatory application										
Public and governement review process										
Construction (subject to regulatory approval)										
Commissioning and start up										

Sources: Natixis, Enbridge



Sources: Natixis, D-Maps



Sources: Natixis, D-Maps

Refining

In large part due to logistics and transportation costs, crude oil imports satisfy around half of Canada's domestic refinery demand. Refineries in western Canada run domestically produced crude oil, while refineries in Quebec and the Atlantic provinces run primarily imported crude oil. Refineries in Ontario run a mix of both imported and domestically produced crude oil. In 2013, refineries located in Ontario and eastern Canada imported approximately 39% of their crude oil supply from other countries, including some from the US, and the price of these imports was based more on higher priced international benchmarks than Alberta prices.

At the beginning of 2013, there were ten refineries operating in Ontario and eastern Canada, with a combined capacity of 1.37mn b/d. Refineries in Ontario refine mostly light crude oil from western Canada and the US, while refineries in eastern Canada run predominantly light crude oil received via tankers from around the world. While eastern Canadian refineries have more supply options, in recent years the cost of supply to these refineries has been significantly higher than those refineries which had access to oil from inland North America.

Due to the higher supply cost, and each site's operational characteristics, some of these refining operations have not been profitable in recent years. In October 2013, Imperial Oil closed its Dartmouth, Nova Scotia refinery, converting it to a products terminal. The Dartmouth refinery had produced most of the gasoline, heating oil, and diesel consumed in Nova Scotia. In Newfoundland, the Come-by-Chance refinery reported losses in 2013 and its owner announced that it was seeking a buyer for the facility.

To gain access to the discounted crude oil from inland North America, refineries in Quebec and New Brunswick have been actively developing rail offloading facilities. Irving Oil began receiving oil by rail in October 2012. Irving can receive 80,000b/d directly, plus 40,000b/d railed to Albany, NY, and then barged to Saint John, New Brunswick. Valero and Suncor started receiving crude-by-rail shipments at their refineries in Quebec in September 2013 and December 2013 respectively. With the reversal and expansion of Line9 by Enbridge from Sarnia to Montreal and expansion of the Energy East pipeline by TransCanada, Quebec and rest of the eastern refineries will soon have access to cheaper inland crude from Alberta and Bakken.

Crude oil Exports from the US to Canada hit an all-time high of 263,000b/d in April 2014 Canadian refiners, the only companies with a free hand to import US-produced crude, have routinely taken advantage of discounted grades like Louisiana Light Sweet and Eagle Ford Shale since the start of 2013. The cargoes are ramping up lately, previously hitting an all-time high of 144,000b/d in January 2014. It costs less than $2/bbl to move crude from the USGC to Canada whereas for US refiners on the East Coast, they need to pay close to $8-10/bbl due to the Jones Act.

There are around nine refineries in western Canada with a total capacity of approximately 760,000b/d. These refineries used approximately 550,000b/d of crude oil in 2013, similar to 2012 volumes.

Demand for Oil and Oil Products

Canadian demand for oil products increased by 0.88% yoy in 2013 to measure 2.3mn b/d. It was mainly driven by LPG, motor gasoline, "other gasoil" and jet kerosene.

Demand for LPG, gasoline, other gasoil and jet kerosene increased by 20,000b/d, 20,000b/d, 30,000b/d and 10,000b/d respectively in 2013. Diesel demand was unchanged and residual oil demand dropped by 20,000b/d.

Around 60% of Canadian gasoline demand emanates from Ontario and Quebec. The western provinces account for around 32% of Canada's gasoline consumption, while the remaining 8% of gasoline is consumed in the Atlantic provinces and the Territories. For diesel, on average, Ontario and Quebec account for around 43% of the diesel fuel consumed in Canada, while the western provinces account for around 46%. The relatively greater dependence on diesel in western Canada reflects regional differences in fleet composition and the comparatively greater need to truck in most manufactured goods to the west from outside the region.

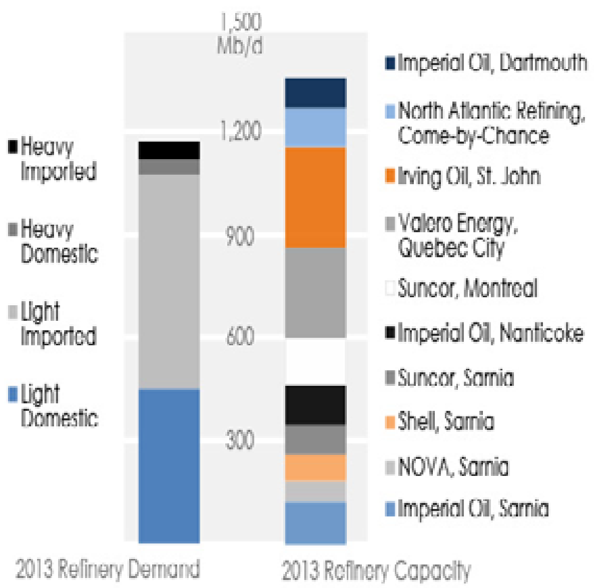
Fuel oil demand decreased by 33% yoy in 2013 to 40,000b/d. Due to the abundant supply of natural gas in western Canada, relatively little furnace oil is consumed in this region. The western provinces (British Columbia, Alberta, Manitoba and Saskatchewan) account for only 6% of the furnace oil consumption in Canada. In contrast, Atlantic Canada (where natural gas is not an option in many markets) accounts for over 30% of Canada's furnace oil consumption despite representing only 7% of the Canadian population.

Forecasts

According to IEA, Canadian demand for oil is expected to rise by 0.9% yoy in 2014 and then decrease by 1.3% yoy in 2015. A comparison with other agencies' forecasts is shown in the table. There has been a significant weakness in Canadian oil product demand in 2014 so far. Demand for diesel and other gasoil has been held back by low industrial optimism and subdued manufacturing activity. The overall increase in domestic demand will be limited in 2014. In 2015, demand is forecast to decline due to industrial and vehicle efficiency gains outweighing the upside from economic growth.

Growth in Canadian demand for oil products has varied widely in recent years. In 2011, passenger travel accounted for 54% of transportation demand, freight for 42%, and the remainder in non-industrial off-road. By 2020 these shares are expected to reverse, with freight ultimately accounting for 56% and passenger transportation 40% by 2035. With the inclusion of longer-term passenger vehicle emission regulations (covering model years 2017 to 2025), energy demand related to passenger travel is expected to decline. Energy demand for freight transportation is driven by growth in the goods-producing industries, and is forecast to grow at an annual average rate of 2% over the coming years. This trend is slower than the 1990 to 2008 historical average of 2.9% per year. This shift is due to somewhat slower economic growth compared to the historical growth rate, as well as federal emission regulations coming into effect for freight trucks (model years 2014-2018). Although these regulations are specified in terms of vehicle emissions, they are expected to reduce future energy consumption by improving vehicle fuel efficiency.

Eastern Canadian refinery capacity and demand (000b/d)



Sources: National Energy Board

Eastern Canadian refineries and major liquids pipelines

Sources: National Energy Board

YoY growth in Canadian crude oil demand (000 b/d)

	2013/2014	2014/2015
EIA	20	120
IEA	20	40

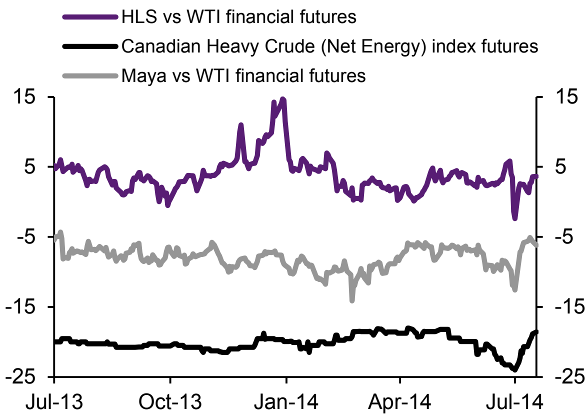
Sources: EIA, IEA

As gasoline is used primarily on the passenger side, and diesel in freight, this shift has implications for the use of these fuels. Over the national energy board's projection period 2011 to 2035, motor gasoline consumption in transportation is expected to decline by 0.2% per year, while diesel consumption increases by 1.6% per year.

Oil Prices and Spreads

WCS-WTI differentials averaged $18.6/bbl in 2014Q2 compared to $21.2/bbl in 2013Q4. The market is expecting a differential of less than $18/bbl for the rest of the year. The lack of alternative supply routes had left Canada's crude oil producers suffering steep discounts to world prices. Much of the differential is determined by upgrading costs and crude-by-rail economics. Availability of rail capacity will remain a significant factor as pipelines continue to be mired in political debate. Increased volume of WCS in PADD3 will also put pressure on other heavy grades in the region in future.

North American regional heavy crudes spreads vs WTI ($/bbl)



Sources: Natixis, Bloomberg, Nymex

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Mexico

In Mexico, the brave reforms initiated by President Enrique Pena Nieto offer potential salvation for Pemex and the Mexican energy industry over the medium term. However, in the short term, they also serve to highlight the dangerous deterioration in Pemex's financial integrity, after a decade of investment which has added little to either current or potential output. This weakness has been compounded by Pemex's growing army of past and present employees, necessitating a proposed restructuring of Pemex's pension system to reduce its outstanding financial obligations.

Given the fall in investment that has occurred over the past few months as Pemex waits to see which of its existing assets it will be allowed to retain, the main near-term risk is a drop in Mexican crude output. While this is unlikely to be nearly as extreme as the drop associated with the rapid decline of Cantarell production, we could nevertheless envisage a decline in Mexican crude output of as much as 200,000b/d between 2013-15.

Mexico - Oil Industry Analysis

Mexico's constitutional energy reforms took effect in December 2013, although implementation of these reforms also requires the passage of a raft of associated bills. Under the reforms, Pemex submitted "round zero" bids seeking entitlement to 100% of existing producing areas, 83% of proven and probable reserves and 31% of prospective reserves. Although scaling back Pemex's rights to prospective reserves to just 27%, Mexico's Secretaria de Energia (SENER) has approved its claims to existing, proven and probable reserves. Subsequent bidding rounds will be open to international energy companies, although Pemex may bid either individually or as part of a consortium.

Where Pemex chooses to enter into alliances or associations with other companies when migrating its existing entitlements into exploration and production (E&P) contracts, this too will require an independent bidding process, conducted by the National Hydrocarbons Commission (CNH), in which Pemex will have no say over its prospective partners, nor the terms on which they are contracted.

Auctions for E&P contracts (either under round zero or subsequent rounds) will be determined according to signature bonuses, exploratory phase fees, royalties and - the determining factor in establishing the winning bid - payment to the Mexican government of an agreed percentage of operating profits or the contracted value of hydrocarbons produced.

Mexico's energy reforms are a very welcome development, potentially opening up the country's energy industry to outside capital and technology. After years of under-exploration and fruitless investment in poorly yielding fields, the reforms are essential to enable Pemex to develop fully its existing reserves, as well as ensuring that the country benefits fully from exploitation of its unconventional oil and gas reserves.

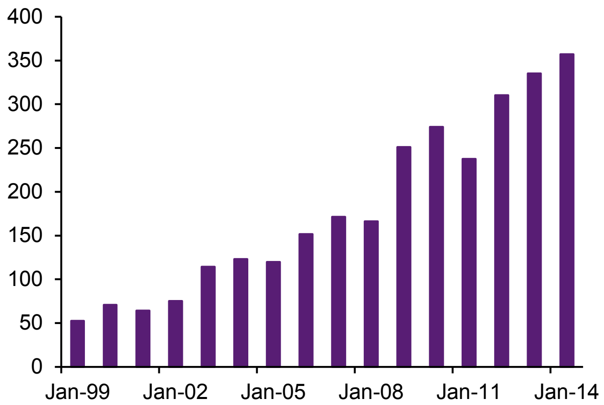
Pemex tax revenue and royalties have made up around a third of total Mexican government revenue over the past decade. The government of Pena Nieto has acknowledged that the tax take from Pemex will inevitably decline, at least in the short run, while other taxes will have to increase to offset the smaller contribution from Pemex.

Mexico is therefore seeking to increase its overall tax base as it has the lowest tax revenue (21.6% of GDP) among OECD countries. The government wants to boost non-oil revenues (14.3% of GDP) via fiscal reform as well as supporting long-term oil revenues (7.3% of GDP) via energy reform.

Under the 2014 budget, Pemex revenues should reach 3.1% of GDP by 2019 vs 2.6% of GDP in 2013 thanks to the energy reform. Meanwhile, federal oil related revenues are expected to reach 6.1% of GDP in 2019, up from 4.7% in 2013.

Mexican crude output has experienced a roller-coaster ride over the past 15 years. At the giant Cantarell field daily output doubled to 2mn b/d in 2003 thanks to a programme of nitrogen injection, but this aggressively shortened the life of the field, resulting in a collapse in output between 2005-2009. Current output at Cantarell is just 200,000b/d, and Pemex plans to invest $6bn (from 2017) in order to sustain Cantarell output over the coming decade.

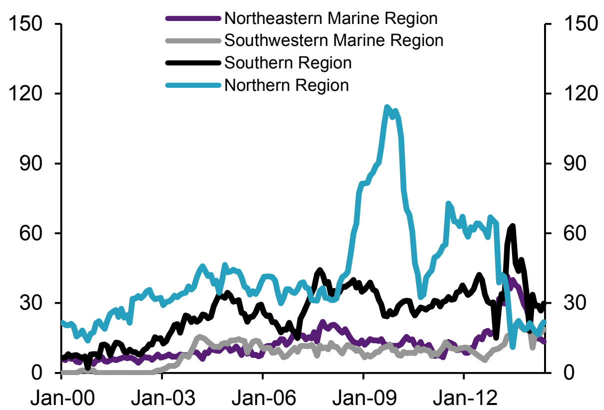
Pemex investment (Ps bn)



Sources: Natixis, Pemex

Over the past decade, Pemex has undertaken a huge investment programme, most of it focused upon new output, spending a total of Ps2.6tn on investment between 2003-2014. Drilling activity increased significantly, especially in the northern region between 2008-12, resulting in a doubling in the number of production wells (oil and gas) between 2008-2013.

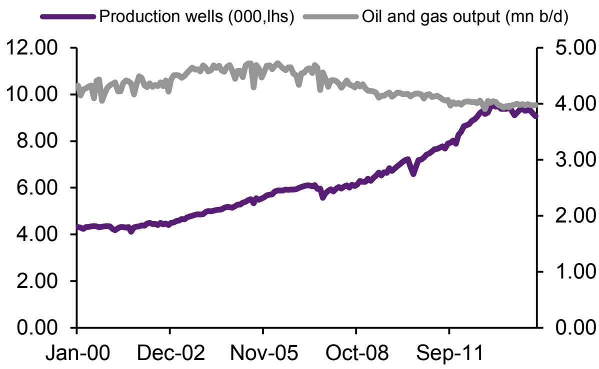
Development drilling rigs



Sources: Natixis, Pemex

As a result of this investment, Pemex natural gas output increased significantly between 2005-2008, rising from 4.5bcf/d to 7bcf/d. Although falling back slightly from this peak, natural gas output has stabilised at around 6.5bcf/d.

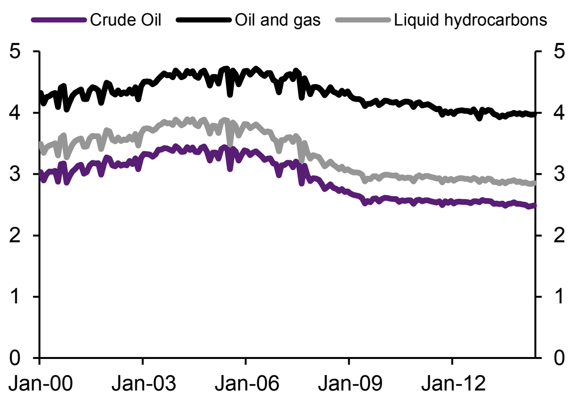
Output vs production wells



Sources: Natixis, Pemex

Pemex oil output has failed to respond to the increase in investment. From a peak of 3.9mn b/d in 2005, crude oil output dropped to 2.5mn b/d in mid-2009, and has remained broadly constant thereafter. Combining oil, other liquids and natural gas (in barrels of oil equivalent), total output peaked in 2005, and has declined steadily since then.

Oil, gas and other liquids output (ooo b/d)



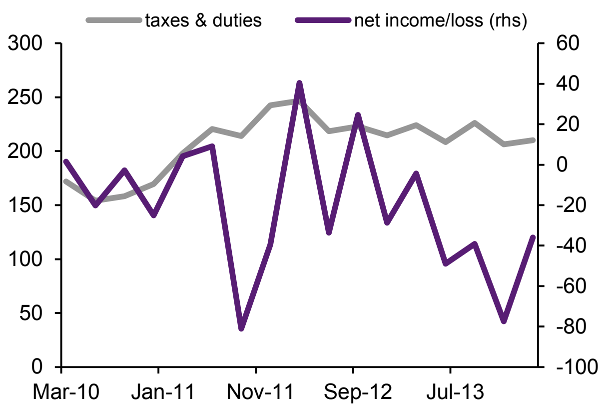
Sources: Natixis, Pemex

What does Pemex have to show for its huge increase in investment over the past decade? Output per well has more than halved, from 1,000boe/d to around 450boe/d. Unlike in Brazil, where investment is contributing incrementally to additional future output, there are no signs that Pemex's investment will yield higher output in future.

What effect is this having upon Pemex? The combination of high investment and a collapse in productivity has

resulted in a shift from profitability into a sustained period of losses, despite high oil prices. Company indebtedness has increased substantially even as output has fallen.

Pemex taxes and P&L (Ps bn)



Sources: Natixis, Pemex

As well as its huge tax burden, PEMEX must also face up to its high and rising bill for on-going staff (and ex-staff) costs. Pemex employs more than 150,000 employees. Its growing army of pensioners and other dependents (retirement age is just 55 and 50,000 workers could retire over the next 6-10 years) has increased its "reserve for employee benefits" liabilities from $36bn in 2008 to $127bn in 2014.

In an acknowledgement of the rapid escalation in Pemex's pension obligations, the Mexican government has proposed shifting up to 30% of the pension obligations to the state in exchange for wider reforms to Pemex's pension system, scaling back benefits to existing and future pensioners. This necessary reform is likely to be deeply unpopular with the unions, hence the upcoming political struggle will give us a good indication of the cross-party willingness to implement those wider reforms necessary to solve Pemex's deep-seated problems.

The energy reforms initiated by the Pena Nieto government are intended to allow Pemex time (and resources) to boost oil output back to previous highs in order to sustain its long-term future and, in parallel, the long-term health of government finances. It is crucial that everyone concerned appreciates the importance of avoiding the mistakes of the past 15 years over the coming decade, otherwise the implications for both Pemex and Mexico could be very painful indeed.

Can the energy reforms succeed? It is worth comparing the proposed Mexican bidding process with that employed by Brazil for its pre-salt production sharing (see table).

There is clearly a great degree of similarity between the two frameworks, which suggests that Mexican authorities may have modelled their system on what they perceive to be the

Rules for E&P contracts - Mexican energy reform proposals vs new Brazil production sharing framework for pre-salt areas

	Mexico	Brazil
Participation of state energy company	Pemex will automatically be a partner in those contracted areas to which it has been granted entitlement under Round zero. Pemex may participate as a partner in subsequent auction rounds.	Petrobras is automatically a 30% partner and operator of each field in all pre-salt auctions.
Signature bonus	Fixed by MoF	Fixed by govt.
Exploratory phase fees / obligations	Monthly fees payable on non-producing areas during exploratory phase. Guarantees seriousness of respective bids. Disincentive to leave fields unexplored.	Fixed minimum exploratory programme. Minimum requirement to source equipment from local suppliers.
Production phase obligations		Minimum requirement to source equipment from local suppliers.
Royalties	Fixed according to the type and price of hydrocarbons being produced by a field	Set at 15% total volume * reference price of oil and gas produced.
Share of profits paid to govt	Payment to MoF, fixed as a percentage of either operating profits or the contract value of hydrocarbons	Govt receives share of profit oil as determined by bidding process.

Sources: Natixis, Pemex

best aspects of the Brazilian model. In particular, if Pemex is allowed to retain entitlement to the vast majority of 1P and 2P reserves that it has bid for in round zero, the two systems will be almost identical.

Is this an appropriate model to follow? There are undoubtedly risks and drawbacks associated with the auction process in Brazil:

- Over-reliance upon a single company creates a problem of high indebtedness and concentration of risk.

- Over-reliance on a single operator limits that company's ability to push ahead with multiple projects. In practice, only those projects that are most profitable are carried out in a timely manner. For example, Petrobras has neglected maintenance of old conventional fields in order to focus its attention on more lucrative pre-salt fields.

- Focus upon major upstream projects can compromise a company's ability to make timely progress on important downstream or infrastructure projects.

There are clearly risks that Pemex could experience similar problems to those faced by Petrobras. Given the major deterioration in Pemex's productivity and profitability in recent years despite high levels of investment, the company already faces major questions in terms of indebtedness, concentration of risk and ability to carry out multiple major projects simultaneously. If it is allowed to retain entitlement to the vast majority of the country's 1P and 2P reserves, these problems could be exacerbated rather than ameliorated over the coming years.

The Mexican government is keenly aware of Pemex's deep-seated problems, and has taken bold measures in an effort to deal with them. Perhaps the biggest downside risk facing Pemex is that the wider state apparatus, supported by public opinion, may underestimate the true extent of the difficulties Pemex currently faces. Failure to execute the energy reforms effectively and efficiently could be devastating for both Pemex and Mexico.

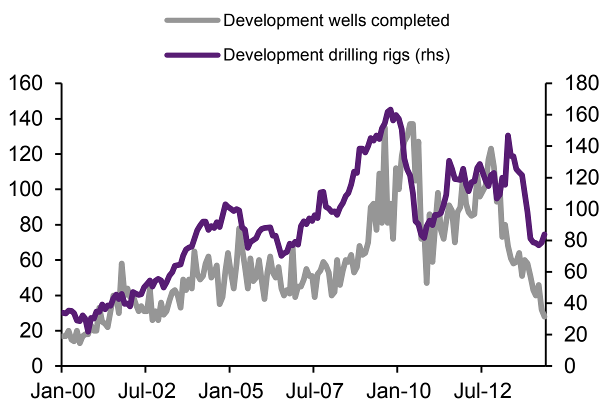
Outlook for Mexican Crude Output

While Brazil's government deliberated over a new bidding process for production-sharing pre-salt fields, this led to a three-year hiatus in auctions which limited investment in new fields and contributed to a stagnation in Brazilian crude output. There is a major risk that the Mexican energy reforms will lead to a similar short-term drop in investment and maintenance while Pemex waits to establish what its new medium-term investment strategy should be.

This risk is already becoming evident from Pemex E&P data. The volume of drilling rigs in Mexico fell by one-third between mid-2013 and 2014. As a result, there has been a sharp drop in the number of exploratory and development wells, with the number of wells completed falling by around two-thirds between 2012 and 2014Q2.

There is therefore a significant risk that Mexican crude supply will decline over the second half of 2014 and during 2015. While there is unlikely to be a repeat of the sharp falls experienced with the (once) giant Cantarell field, a more rapid rate of decline than was experienced during the recent period of heavy investment (2009-2012) is very likely. From almost 2.9mn b/d of liquid hydrocarbons output in 2013, we would not be surprised to find Mexican volumes falling to 2.7mn b/d in 2015, if not lower.

Pemex E&P: development wells



Sources: Natixis, Pemex

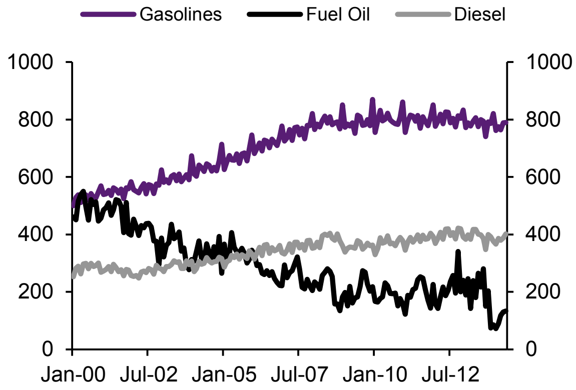
Mexican Refining Industry

Total Pemex oil product output has remained broadly unchanged over the past 15 years. A modest decline in fuel oil output has been offset by small increases in gasoline and diesel production, with total refinery throughput remaining largely unchanged.

Total Mexican oil product sales have remained broadly unchanged over the past decade. A rapid increase in gasoline consumption up to 2008 has subsequently been followed by unchanged sales volumes. Diesel consumption has increased steadily over the past decade (up an average of 3% per annum). At the same time, there has been a sharp decline in Mexican fuel oil consumption as electricity generators have switched from fuel oil to cheaper natural gas.

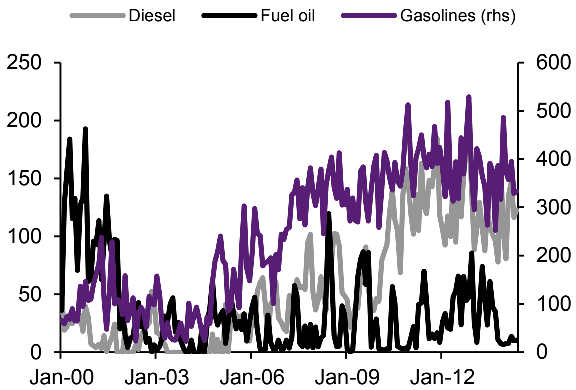
As a result of these structural changes, Mexican exports of gasoline and diesel have dropped to zero since 2010. In contrast, there has been a sharp increase in Mexican fuel oil exports since 2006. On the other side of the equation, there has been a substantial increase in gasoline imports since 2004, alongside a modest increase in diesel imports over same period. Fuel oil imports have fallen to negligible levels.

Petroleum product sales (000 b/d)



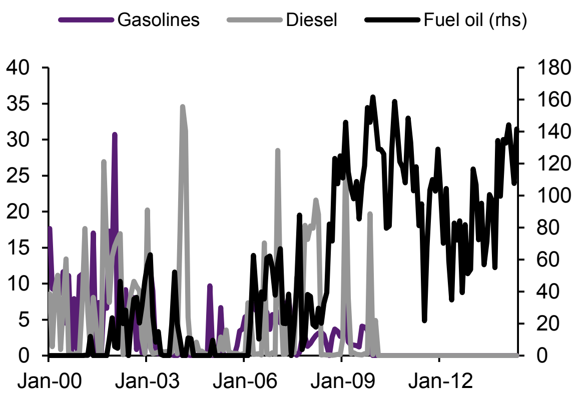
Sources: Natixis, Pemex

Oil product imports (000 b/d)



Sources: Natixis, Pemex

Oil product exports (000 b/d)



Sources: Natixis, Pemex

Demand Forecasts

Alongside a gradual improvement in GDP growth, Mexican demand for diesel is expected to continue growing at around 2-3% per annum. With gasoline demand seen broadly unchanged, and little scope for fuel oil consumption to drop much further, this should result in an increase in Mexican oil product demand of a little less than 1% per annum over the coming years.

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Brazil

Brazil's oil industry has underperformed for a number of years, with output declining since the peak in late-2010/early-2011. Despite expectations for a strong rebound in output during 2014, the first half of the year has delivered another disappointing result. However, the headline numbers obscure a widening disparity between on-going weakness in conventional oil output versus rapidly expanding pre-salt output. The development of its pre-salt fields is clearly one of the strongest features of the Brazilian energy industry, and this could indeed lead to an acceleration in Brazilian crude output from 2015 onwards.

Supply

Over the past four years, Brazilian crude output has consistently disappointed, with total output dropping well below 2011 peak levels despite a steady increase in pre-salt production. The reasons for this shortfall are many and various. An accident at the Frade field caused production shutdowns in 2011. Fields operated by OGX failed to deliver, contributing to the company's eventual insolvency. Auctions of new fields were halted between December 2008 and May 2013 while the government sought agreement upon a new legal framework for pre-salt auctions and distribution of their anticipated profits. Development of pre-salt oil came at the expense of necessary investment in the upkeep of conventional fields, accelerating decline rates elsewhere.

Despite these setbacks, Petrobras has set itself a target of increasing crude output by 7.5% in 2014, as it attempts to double output between 2010-2020 to 4.2mn b/d. Here, we assess the progress made over the past year, in an effort to determine whether these goals will be achievable.

Libra Auction

In 2013, the Brazilian government undertook three rounds of auctions for oil and gas fields. Round 12, in October, was the first auction of pre-salt oilfields, focusing upon the giant Libra field. This auction was conducted under a new bidding structure, under which Petrobras was guaranteed a 30% stake in any winning bid. Rather than bids taking place in terms of up-front royalty payments, winning bids were to be ranked according to the share of "profit oil" that would be paid to the government.

The Libra auction was won by the sole bidder, a consortium made up of Petrobras (40%), Royal Dutch Shell (20%), Total (20%), CNOOC (10%) and CNPC (10%). The consortium paid a fixed R$15bn up-front fee, while the Brazilian government will receive 41.65% participation in all "profit oil" produced at the field. The consortium plans to drill an initial six exploratory wells, in addition to conducting an extended well test.

When will the next pre-salt auction take place? The requirement for Petrobras to be a 30% partner and sole operator in any winning bid places huge financial and operational obligations upon the company. This makes it especially difficult for the Brazilian government to conduct regular auctions of major pre-salt fields.

Ahead of the upcoming 5 October 2014 elections, the various presidential candidates have suggested alternative solutions to this problem. While President Dilma Rousseff would maintain the existing framework, auctioning major pre-salt fields on an irregular basis (next auction planned for 2016), other candidates have suggested that the auction process should be freed up to allow other oil companies to operate fields as well as Petrobras, which would facilitate a more rapid development of pre-salt oilfields.

Output Projections

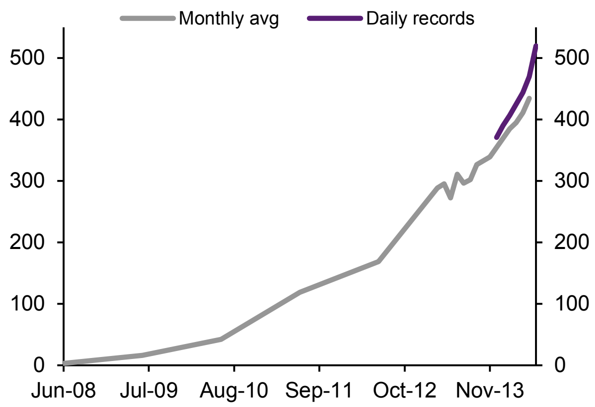
Petrobras expects to raise output by 7.5% in 2014 (+/-1%). In the year to April, output was 0.8% lower yoy at 2.045mn b/d, hence achievement of this year's target will require average monthly output of 2.3mn b/d for the remainder of the year.

Pre-salt wells may be expensive and time consuming to drill, but their hit rates are high, and flow rates are excellent. In contrast to North Sea wells which typically produce around 15,000b/d, and Gulf of Mexico wells which produce around 10,000b/d, pre-salt wells in the Santos basin are generating around 25,000b/d, with the more productive wells achieving flow rates in excess of 30,000b/d. This productivity per well is significantly higher than had been expected. For example, Petrobras' FPSO Cidade de Angra dos Reis in the Lula field has had its 100,000b/d capacity filled by four wells (24,000b/d each) instead of the expected six wells (16,000b/d per well).

Drilling efficiency has improved as Petrobras has gained experience. In 2006, the first pre-salt well drilled took 134 days. By 2013, drilling times had been reduced to just 60 days.

The combination of high hit rates, shorter drilling times and higher than expected flow rates (especially in the Santos basin) has resulted in pre-salt output growing at an increasingly rapid pace. Despite the fact that Petrobras' output has disappointed in the last few years, there is therefore scope to be more optimistic about future output. From less than 300,000b/d in early-2013, average Petrobras pre-salt output reached 435,000b/d in May. June's record high pre-salt output of 520,000b/d was achieved with only 25 producing wells; ten in the Santos basin and fifteen in the Campos basin.

Petrobras pre-salt output (000b/d)



Sources: Natixis, Petrobras, various

Petrobras plans to add 5 new FPSOs this year. 17 new pre-salt wells are scheduled to be connected to platforms that are already in position, while another five will be connected to newly positioned platforms. Collectively, this is expected to add as much of 550,000b/d of new crude output. While the slow start to this year's production makes achievement of Petrobras' 7.5% growth target difficult, the additional crude supplies due to come on-stream clearly highlight the potential for a more rapid increase in Brazilian crude output over the coming years.

In 2015-16, Petrobras plans to add eight new pre-salt platforms in the Santos basin (one in 2015, followed by seven in 2016, focusing in particular on the Lula field). Once up and running, this is expected to take pre-salt output above 1mn b/d.

Petrobras CEO Maria das Gracas Silva Foster plans to increase output to 4.2mn b/d by 2020, of which pre-salt output will contribute 2.2mn b/d. Output from third party producers, which contributed a negligible amount in 2013, is expected to add an additional 800,000b/d, taking total Brazilian crude output to around 5mn b/d by 2020. This will require Petrobras' investment of $221bn between 2014-18, of which $154bn will be exploration and production. Including the $45bn share of investment by Petrobras' partners, close to $200bn will be invested in exploration and production alone.

One important factor behind the slowdown in Brazilian crude output since 2011 has been the sharp decline rate at conventional fields, especially those in the Campos basin. From more than 1.75mn b/d at the peak in 2012Q1, Petrobras' output in the Campos basin fell to a low of less than 1.43mn b/d in February this year. With pre-salt output in the Campos basin generating 200,000b/d or more this year, this puts the overall decline in conventional output in the Campos basin somewhere around 500,000b/d.

In large part, these decline rates at conventional fields were a reflection of Petrobras' increased focus upon pre-salt fields, exacerbated by the company's squeezed profitability and scarcity of capital. In an effort to support output levels at mature fields, Petrobras has contracted four new service platforms that will carry out maintenance at offshore platforms over the period 2014-17. By April 2014, efficiency rates at Campos basin platforms had already recovered to 81%, their highest level in almost four years. If this improvement can be maintained, then higher conventional output will complement the additional crude being generated by pre-salt wells.

Petrobras' 2014 output target looks particularly challenging given its slow start to the year. Nevertheless, the acceleration in pre-salt oil production clearly demonstrates the potential for higher crude output in the near future, especially if decline rates at existing conventional fields can be arrested. We would therefore expect Brazilian crude output to increase by somewhere between 50-75,000b/d this year, with the possibility of a more substantial increase in output during 2015.

Achievement of Petrobras' 2020 target of 4.2mn b/d appears challenging given the company's poor track record in recent years, but the combination of high hit rates, shorter drilling times and high flow rates at pre-salt wells all suggest that output can increase significantly over the coming five years. With improved productivity at these pre-salt wells, there is also greater optimism surrounding the potential output that may be contributed by Petrobras' partners in these new fields over the coming decade. There is therefore a good chance that Brazilian output will exceed 3mn b/d by 2020.

Brazil's Refining Industry

Petrobras currently operates 12 refineries, with a collective capacity of around 2mn b/d. For Petrobras, shortage of available refinery capacity represents a major problem, since the company has an obligation to supply oil products to the Brazilian market at prices fixed by the government. This forces the company to import products such as gasoline and diesel when local refining capacity proves insufficient to meet demand. As a result, Petrobras is investing heavily in new refineries, in an effort to reduce losses in its refinery business caused by fuel imports.

Petrobras' target is to increase refinery capacity to 3mn b/d by 2020. The additional capacity is due to come from four new refineries. The first, RNEST, is expected to come on-line in November, operating initially at 115,000b/d, with full-capacity of 230,000b/d due to be achieved in mid-2015. Petrobras' 150,000b/d Comperj refinery is due to come on-stream in Aug16.

Petrobras is exploring potential JVs with China's Sinopec and South Korea's GSS Holdings to facilitate the construction of two 300,000b/d low-sulphur diesel refineries; Premium 1 and Premium 2. The first of these refineries is planned to come on-stream in 2017, doubling capacity thereafter by 2020.

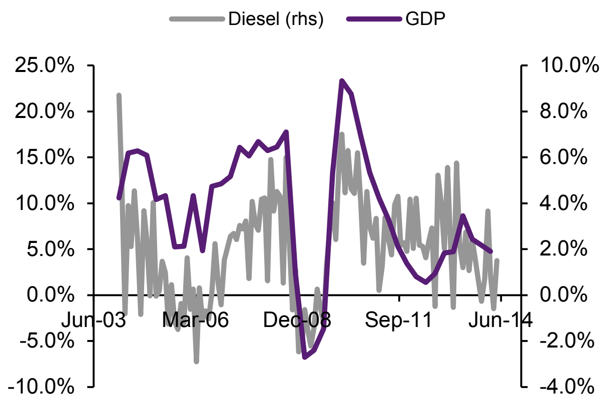
So far, Petrobras' experience with these new refinery projects has been painful. RNEST is arriving three years late, while costs have increased four-fold vs initial estimates. This JV between Brazil and Venezuela has suffered extensive cost overruns linked to the need for additional treatment facilities for the heavy Venezuelan crude expected to be used (40% input) at the refinery. Similarly Comperj has suffered almost four years of delays, with costs increasing 61% to $13.5bn.

With just $39bn planned for downstream investment between 2014-18 (40% less than the 2013 plan), there is little room for error in the remaining projects. Any further cost overruns and delays will impact both the investment budget as well as the ongoing profits of the company's refining unit.

Demand for Oil Products

Growth in Brazilian demand for diesel has been linked closely to GDP, as can be seen from the chart below. With our forecasts anticipating growth in GDP of just 1-1.3% in 2014-15, Brazilian demand for diesel is likely to grow relatively slowly over the coming 18 months.

Growth in diesel sales vs GDP (%, yoy)

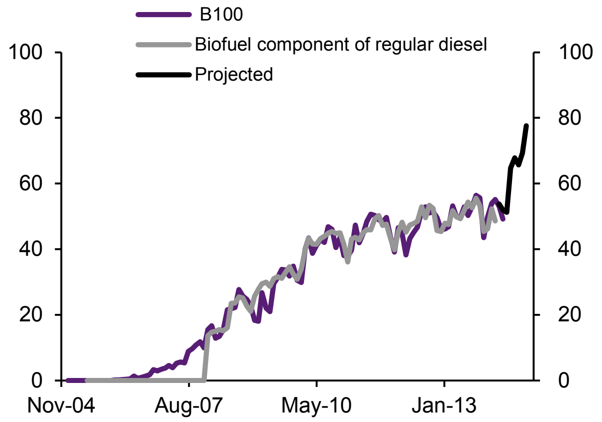


Sources: Natixis, Bloomberg, ANP

Between 2005 and 2010, Brazilian output of biodiesel increased from zero to over 40,000b/d. This coincided with a steady increase in the mandated minimum blend of biodiesel within regular diesel. From 2% in early-2008, the minimum biodiesel content of regular diesel increased to 3% in Jul08, 4% in early-2009 and 5% in Jan10. This growth in biodiesel output helped to accommodate the rise in demand for diesel, limiting the increase in diesel imports over this period. Between 2010 and 2014, the expansion in biodiesel production slowed significantly, reflecting the constant 5% minimum share of biodiesel in regular diesel. Alongside high domestic refinery utilisation rates, limiting local output of diesel, this has contributed to a substantial increase in imports of diesel since 2010.

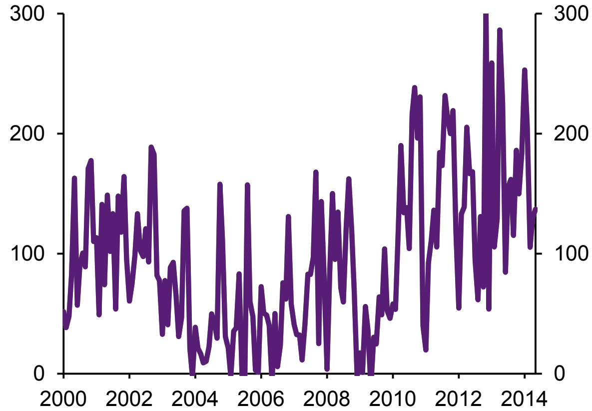
In July 2014, the minimum mandated share of biodiesel within regular diesel was increased to 6%. This will rise further to 7% in November 2014. The Brazilian biodiesel industry should be capable of meeting this higher output volume, given that its 57 biodiesel plants currently have a total capacity of around 7.5bn litres per annum (close to 130,000b/d). Together, these two increases will raise Brazilian biodiesel output by over 20,000b/d, reducing demand for diesel by around 17,000b/d. In combination with slow economic growth, this higher share of biodiesel will help to reduce growth in Brazilian demand for diesel. From growth rates of around 4% in recent years, we would expect Brazilian demand for diesel to increase by no more than 2% per annum in 2014-15.

Brazil biodiesel production (000b/d)



Sources: Natixis, ANP

Net diesel imports (000b/d)

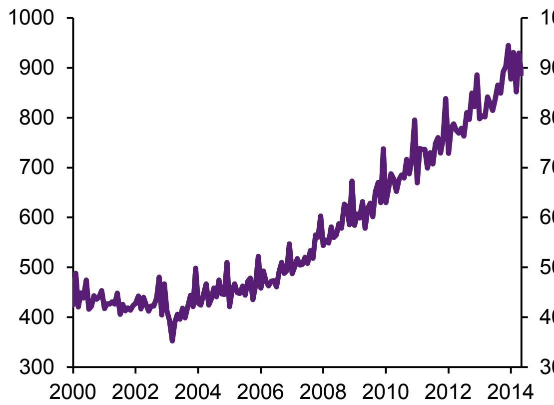


Sources: Natixis, ANP

Brazilian demand for automotive fuel has grown steadily in recent years, expanding by around 7.7% per annum since 2004. Even during periods of economic weakness, demand has increased by 5% or more each year. During 2013, Brazilian demand for automotive fuel increased by around 50,000b/d (in gasoline energy-equivalent terms). In part, this can be traced to new vehicle sales which were stimulated by lower IPI taxes and FINAME financing. Despite its budgetary problems, Brazil will extend until year-end the tax cuts on vehicle purchases which were introduced two years ago. The outlook for the car industry is nevertheless challenging due to (i) lower demand as the IPI tax expires and consumption slows and (ii) stricter credit conditions with higher interest rates and a reduction in subsidized credit.

Demand for automotive fuel has also been supported by the mismatch between different sectors of the economy. Private consumption has been relatively robust (+2.2% yoy in 2014Q1) compared to investment (-2.1% yoy in 2014Q1) thanks to a tight labour market (only 4.9% unemployment in April), abundant public credit (22.4% yoy growth in household credit in April) and dynamic nominal wages (+8.9% yoy in April).

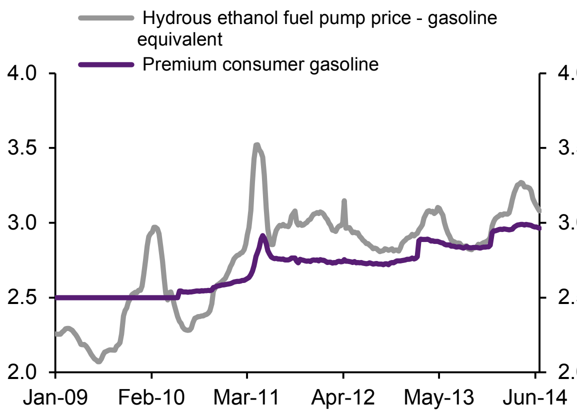
Total demand for automotive fuel (000b/d gasoline equivalent)



Sources: Natixis, ANP

On top of this steady growth in demand for automotive fuel, Brazilian demand for gasoline is increasingly becoming a function of the energy-equivalent price differential between ethanol and gasoline. This relationship is caused by the fact that gasoline prices have remained fixed at a low level by the Rousseff government, while Brazilian vehicles are generally flexible enough to run on either gasoline or ethanol.

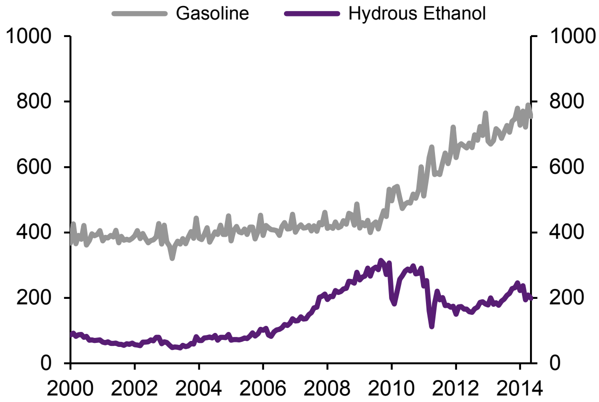
Hydrous ethanol vs gasoline prices (R$/l)



Sources: Natixis, Bloomberg, FOL

Petrobras has an obligation to supply the local market with as much fuel as is demanded. With its local refinery capacity (and therefore gasoline output) now running at close to maximum levels, Petrobras must therefore purchase additional fuel on the international market in order to satisfy incremental consumer demand.

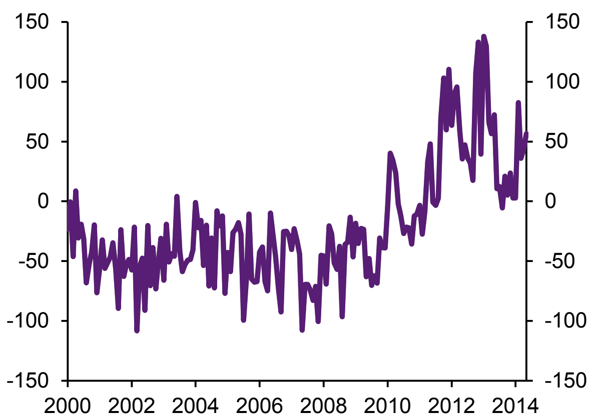
Sales of oil products (000b/d)



Sources: Natixis, ANP

Since 2009, periods in which Brazilian gasoline has been cheaper than ethanol have coincided with sharp increases in imports of gasoline. While spikes in ethanol prices in 2010Q1 and 2011Q2 led to short bursts of gasoline imports, the trend became more firmly established during 2012, when Brazilian ethanol prices remained higher than gasoline prices throughout the year as a whole.

Net gasoline imports(000b/d)



Sources: Natixis, ANP

This has had a damaging effect upon Petrobras' profits, which are now inversely related to the price of ethanol. During periods of high ethanol prices, an increase in international gasoline prices becomes additionally damaging for Petrobras.

After a decade enjoying the benefits of being a net exporter of gasoline, the cost to Petrobras of importing gasoline has become an increasingly significant problem, with the gasoline import bill rising to a high of around $2.9bn in 2012. Since then, a narrowing of the spread between ethanol and gasoline prices has reduced this import bill to around $2bn per annum, as gasoline imports dropped from 23.9mn bbl in 2012 to 18.24mn bbl in 2013.

Our forecast for Brazilian demand for automotive fuel anticipates further growth in consumption as a result of supportive government policies and low gasoline prices. Growth rates are unlikely to be as strong as recent years, however, due to the deceleration in economic growth and accompanying slowdown in sales of new automobiles. Forecasting Brazilian demand for gasoline, however, is more complex since it requires a forecast for the local price of ethanol. During the 2009-2011 period, volatility in international sugar markets caused large spikes in Brazilian ethanol prices. Since then, the lower volatility in sugar prices has been mirrored by broadly unchanged ethanol prices. At the same time, the Brazilian price of ethanol has not fallen as far as international sugar prices vs their peak in early 2011. This may in part reflect the higher cost of supplying ethanol after Brazilian authorities introduced rules in 2011 requiring producers to maintain stocks equivalent to 8% of their previous year's output, and distributors to maintain stocks of ethanol-gasoline mix equivalent to 15 days of average sales.

Assuming that Brazilian gasoline prices remain higher than ethanol prices, we would anticipate Brazilian demand for gasoline increasing by around 5-6% per annum between 2014-15.

Taken together, our forecasts for Brazilian diesel and gasoline demand suggest an increase in overall Brazilian oil product demand of around 50,000b/d in 2014, to be followed by a similar increase in 2015. Given the on-going delays in construction of Brazil's new RNEST and Comperj refineries, this will further exacerbate Petrobras' oil product import bill, to the detriment of its current profitability and potentially also some of its outstanding investment projects.

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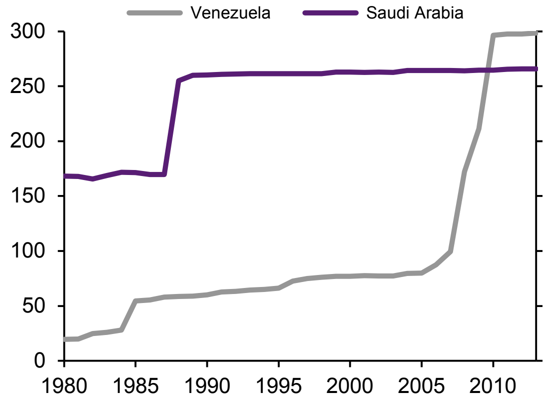
Venezuela

Venezuela may have the largest crude reserves in the world, but acute economic mismanagement is preventing the country from achieving even a fraction of its energy potential. Under circumstances in which sovereign default would otherwise have been inevitable, Venezuela's finances are currently being propped up by Chinese credit. While this helps to preserve the flow of cheap crude exports to China, its perpetuation of the economic status quo is nevertheless proving detrimental to those (mainly Chinese) energy companies which are attempting to develop the country's vast Orinoco Belt reserves.

Venezuela has the highest proven oil reserves in the world, with the latest data putting proven reserves at almost 300bn bbl. The huge increase in proven reserves between 2005 and 2010 was due to the discovery of extra-heavy tar-like crude in the Orinoco belt. This crude has an API of around 8-9°, requiring either blending with lighter crude or upgrading before it can be transported and sold.

Proven oil reserves (bn bbl)

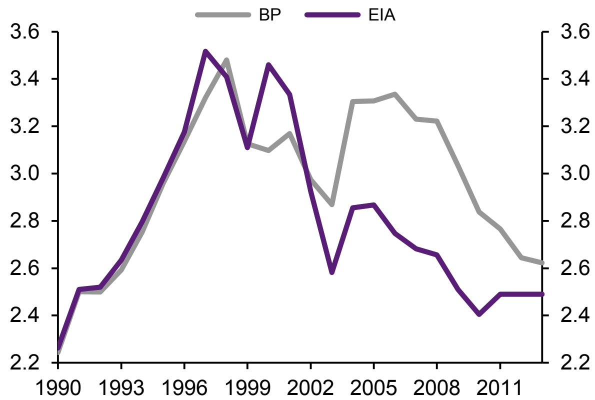


Sources: Natixis, BP

Crude Output

Venezuelan crude output has fallen substantially over the past decade, although the precise dimensions of this fall are difficult to establish given the wide variation in published data provided by different sources. While Venezuelan agencies put current output levels close to 2.9mn b/d, international estimates are generally 2.6mn b/d or less.

Venezuela oil production estimates (mn b/d)

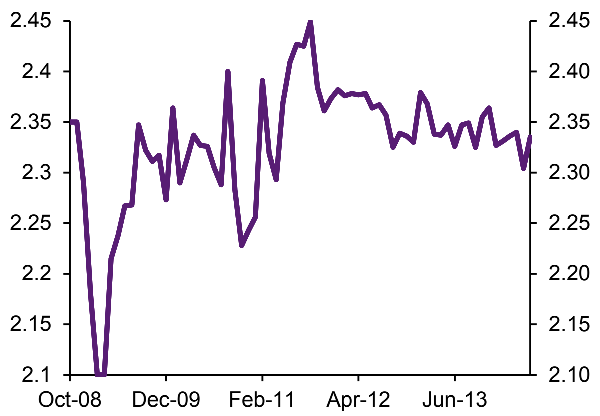


Sources: Natixis, BP, EIA

According to OPEC data, Venezuelan crude output rose briefly during the latter part of 2011 to over 2.4mn b/d, before drifting lower over the next three years. In April 2014, output hit a 3-year low at just 2.3mn b/d. This trajectory is sharply at variance with the country's aspirations for higher crude output over the period 2012-14, which included an initial forecast for oil output in excess of 3.5mn b/d in 2014. What has gone wrong?

At its mature conventional fields, a steady decline in output since 2008 has prompted Venezuela to encourage its international partners in the 20 joint ventures to raise finance to enable PDVSA to boost output. The lack of forthcoming finance for expansion is testament to the wide range of problems faced by international companies in Venezuela. The JV partners have complained about late payment of dividends by PDVSA, high taxes in Venezuela and the difficulty of transferring cash income from Venezuela to overseas accounts. While some finance has been provided by PDVSA's international partners, in the main it has not been enough to arrest the decline in output at these mature conventional fields.

Venezuela crude output (mn b/d)



Sources: Natixis, OPEC

Venezuela's efforts to raise crude output over the past few years have centred upon the vast heavy oil fields of the Orinoco belt. Since 2008, Venezuela has either allocated or auctioned off a range of prospective fields in this region, in particular in the Junin and Carabobo blocs, enticing international oil companies to participate in joint ventures with state oil producer PDVSA.

Petrocarabobo (Carabobo 1 - auctioned) achieved initial oil flow in December 2012. In Phase 1, output was expected to reach 30,000b/d, rising to 90,000b/d in Phase 2. Instead, output has remained extremely limited, prompting Petronas to abandon its share of the JV in 2013.

Petroindependencia (Carabobo 3 - auctioned) was expected to reach 15,000b/d by the end of 2013. Instead output failed to exceed 500b/d due to a lack of transport infrastructure.

Petromacareo (Junin 2) achieved 800b/d from its first well in September 2012, with five wells operational by the end of the year. Despite this, Petrovietnam suspended operations in January 2014 due to rampant inflation (56% in 2013) and extortionate exchange rate differentials between official and black market rates.

Petromiranda (Junin 6) had five wells in operation by the end of 2012, producing around 1,200b/d each. Despite this, Lukoil abandoned its share of the JV in late-2013.

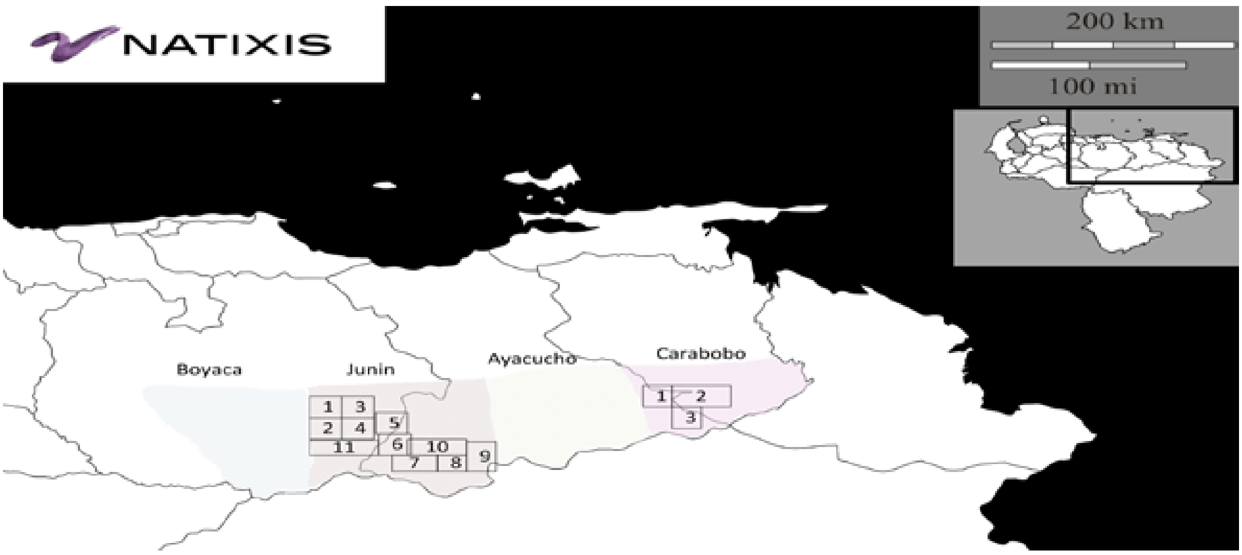
Petrojunin (Junin 5) commenced production at its first well in March 2013. Plans expected to raise output to 15,000b/d by end-2013, but output was limited to just 2,800b/d in December 2013.

Petrourica (Junin 4) constructed 65km of new or upgraded roads in order to facilitate transportation of initial crude output.

PDVSA achieved initial crude production at Junin 10 in 2012, despite the withdrawal of both Total and Statoil from the original Petrocedeno JV. Since then, CNPC has stepped in as a new partner.

Collectively, the new Orinoco-belt JVs produced less than 25,000b/d in 2013Q4. The reasons for this hugely disappointing output are many, but the more significant problems can be summarised as follows:

Venezuela's Orinoco heavy oil belt



Sources: Natixis, D-Maps

- Lack of transport infrastructure. Plans to introduce tank farms and pipelines have not been implemented. The blending of heavy Orinoco crude with lighter oil and transportation of the resultant blended crude to port terminals on the coast has therefore been heavily constrained.

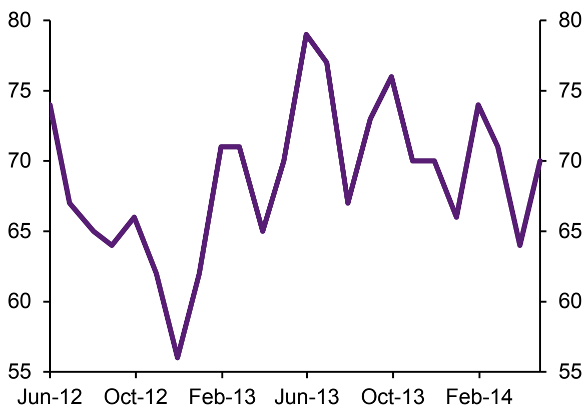
- Port facilities are similarly lacking, with tank farms and export terminals still stuck at the planning stage.

- During the initial production phase, heavy oil was intended to be blended with lighter oil, with the resultant exports providing financing for construction of expensive upgraders that would, in turn, facilitate output of synthetic crude. With no initial supply of crude there has been no finance available for construction of upgraders.

- It is becoming increasingly impossible to do business within the broader macroeconomic climate in Venezuela. Bringing money into the country is rendered virtually impossible by the yawning gap between official and black market exchange rates (or even between the different levels of official SICAD rates). Taking money out of the country is equally impossible, as international airline companies will testify. Money held in local currency devalues too quickly for cash management to be practical.

It is these problems that appear to be behind the withdrawal of many of PDVSA's international partners, despite the fact that wells were already being drilled and output could have increased.

Venezuela active oil rig count

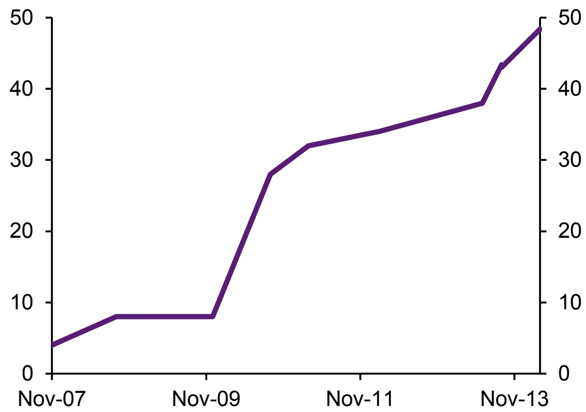


Sources: Natixis, Baker Hughes

According to OPEC data, active drilling rigs in Venezuela increased from around 120 in the period 2009-11 to 149 in 2013. However, Baker Hughes data contradicts this picture, suggesting that active oil rig counts in Venezuela have remained broadly static in recent years at around 70.

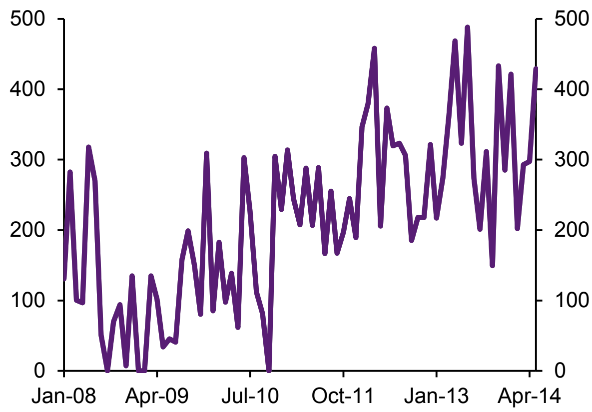
It is difficult to see how this situation can improve without a substantial restructuring of Venezuela's economy. For now, this seems unlikely, given the way in which the current government is being financed by Chinese lending. Since 2007, Chinese oil-related loans to Venezuela have totalled more than $48bn. Some of these loans were intended to finance investment in oil infrastructure. Some were loans backed by prospective oil exports to China. China benefits from the heavily discounted price of oil inherent in the repayment of these loans via crude exports. Over time, Venezuelan exports of crude to China have increased as exports to the US have diminished. As a result of this shift from US exports to Asian exports, PDVSA has relocated its Caribbean port facilities from the Bahamas to Aruba and St Eustatius.

Outstanding oil related loans from China to Venezuela ($bn)



Source: Natixis

Venezuela oil exports to China (000b/d)



Sources: Natixis, Bloomberg

Given that participation in the Orinoco belt JVs has progressively migrated towards Chinese oil companies as other international oil companies have withdrawn, one

might reasonably expect there to be growing pressure from PDVSA's Chinese partners to make more substantial progress with the infrastructure necessary to facilitate crude exports from the new Orinoco-belt fields. Nevertheless, preservation of the current socio-economic status quo does appear to be more of a hindrance than a support to those companies attempting to develop the Orinoco belt.

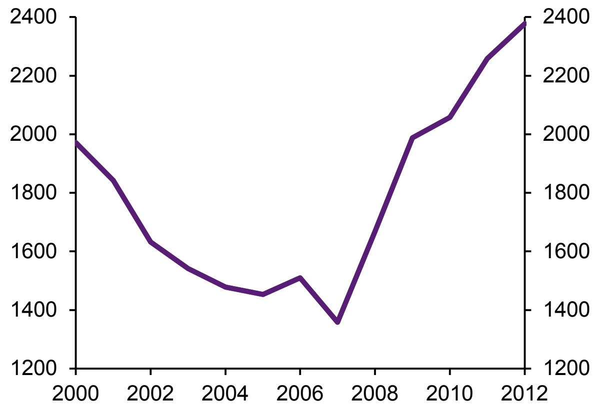
For these reasons, we would envisage that the current gradual decline in Venezuelan crude output is likely to continue over the coming year at least, resulting in a decline of as much as 50-75,000b/d in average daily crude supply between 2013 and 2015. Venezuelan crude output will only begin to increase once adequate infrastructure is put in place. Furthermore, it may require a fundamental shift in the underlying structure of Venezuela's economy before there are adequate financial incentives for international oil companies to maximise output from these new heavy oil fields.

Colombia

Colombia has experienced a great deal of success over the past decade in expanding its energy output, as a restructured energy industry has benefited from the advantages of increased private sector involvement. These gains may prove increasingly difficult to sustain, however, particularly if the government is unsuccessful in its efforts to negotiate peace with the country's various armed guerrilla factions.

Colombia's experience over the past decade offers an object lesson in the potential benefits of structural change, in particular for the country's oil industry. In the period 2000-2004, after a period of underinvestment in new and existing capacity, crude output was declining and proven reserves had fallen to just half their 1995 levels.

Colombia - proven reserves (mn bbl)

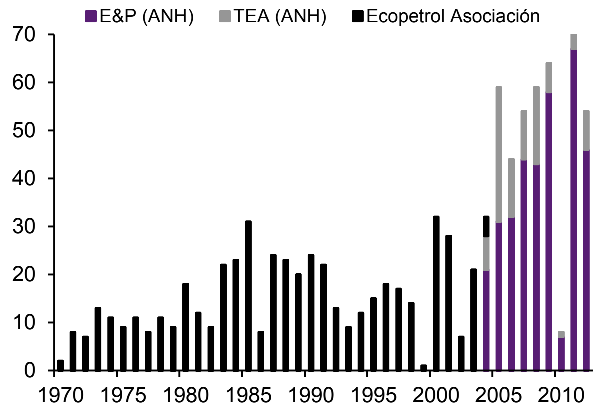


Sources: Natixis, ANH

Under demands from the IMF, Colombian authorities restructured state oil company Ecopetrol in 2003 in order to qualify for a $2.1bn loan. Regulatory and administrative powers were divested into a new body, the Agencia Nacional de Hidrocarburos (ANH).

In 2004, further reforms were enacted to allow foreign oil companies to operate in Colombia without needing to be in partnership with Ecopetrol. Still 100% state-owned, Ecopetrol now had to compete with private companies for production contracts. ANH began to auction new fields for Exploration & Production as well as Technical Evaluation Agreement contracts (instead of the previous association deals with state-controlled Ecopetrol).

Ecopetrol Associations vs ANH contracts



Sources: Natixis, ANH

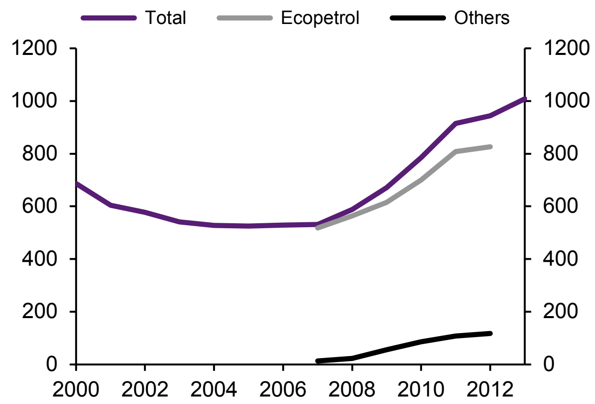
From 2005, the volume of new exploration, production and technical assessment contracts began to increase rapidly relative to the number of previous association agreements undertaken by Ecopetrol.

By 2007, proven reserves had fallen to less than 1.4bn bbl, although the new E&P and TEA contracts would soon begin to turn this decline around. Output started to emerge from contracts with private companies. The Colombian government sold an 11.5% stake in Ecopetrol.

Between 2008 and 2011 crude output increased at both Ecopetrol and the various private sector contracts in Colombia, taking overall output to over 900,000b/d in

2011. Thanks to extensive investment in new fields, proven reserves also recovered, rising from a low of 1.4bn bbl to 2mn bbl in 2011. By 2013, crude output exceeded 1mn b/d, while proven reserves had recovered to 2.4bn bbl.

Colombian crude output (000b/d)



Sources: Natixis, ANH

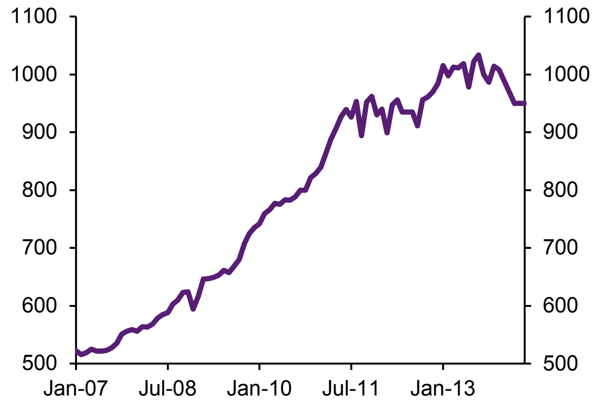
While the improvement in the Colombian oil industry over the past decade has been remarkable, the government still faces substantial challenges. First, proven reserves remain limited relative to current levels of output, at just seven years of production. Second, the country continues to struggle with the on-going presence of a number of armed rebel groups. This makes Colombia's oil infrastructure vulnerable, as well as increasing the risks attached to new exploratory contracts for blocks in remote parts of the country.

In its 2014 contract round, the Colombian government is auctioning 95 blocks. While much of the increase in Colombian output over the past decade has come from heavy oil plays, the 2014 auction round steps into new, unconventional territory with 18 blocks containing potential shale-bed reserves.

In 2012, President Santos began peace talks with the FARC rebel group. In 2014, peace talks also commenced with the National Liberation Army. This coincides with an increase in attacks on oil infrastructure. At the same time, indigenous groups have been demanding substantial claims for damages from oil exploitation, and holding up vital repairs to damaged infrastructure. In 2013, attacks on Colombian pipelines rose to 259, up 72% yoy. In 2014, these attacks have continued, leading to the closure of major pipelines for extended periods. As a result, Colombian crude output dropped to around 950,000b/d between March and May.

After a period of rapid improvement over the past ten years, Colombian oil output may struggle to maintain the high levels achieved in 2013. Both investment in new output and the integrity of the current infrastructure has come under pressure from political tensions between rebel groups, the government and indigenous people. We would therefore expect Colombian crude output to remain at or below its 2013 levels until the government has made greater progress in resolving issues with local communities, thereby providing greater security for pipeline infrastructure and the exploration of new fields in remote areas.

Colombian crude output (000b/d)



Sources: Natixis, ANH, various

Oil Price Outlook

Natixis crude oil price outlook

		2014				2015				
		Last Price	Q3	Q4	Annual average	Q1	Q2	Q3	Q4	Annual average
Energy		**Spot**								
Brent	USD/bbl	102	107.25	107	107.89	109	103	108	107	106.75
WTI	USD/bbl	97.35	99	98.5	99.69	102	97	102	101	100.5

In order to estimate Brent prices for 2014 and 2015, we believe that the main drivers will be physical balances, geopolitics and OPEC policies. For now, physical balances are very much skewed towards excess supply. We expect growth in non-OPEC supply in 2014 to be around 1.25mn b/d, lower than OPEC and IEA's latest monthly projections. Within this total, the majority of the additional crude is expected to come from North America, where oil output is forecast to increase by 1.1mn b/d in 2014. There is also expected to be small growth in European and Russian oil output in 2014. We do not expect to see any growth in South American oil output in 2014.

In 2015, we expect non-OPEC supply to increase by 1.3mn b/d. Once again, the main driver of non-OPEC supply will be North American unconventional crude oil, where supply is expected to rise by 1.15mn b/d in 2015. A positive growth contribution is also expected from Latin America.

On the demand side, we expect global demand for crude to increase by around 0.9mn b/d in 2014. Although growth in demand is expected to be better than 2013, our growth forecasts have nevertheless been revised downwards in recent months due to weaker than expected consumption emanating from two of the largest oil consuming countries, ie China and Europe. We expect US demand to grow by 171,000b/d in 2014 and 115,000b/d in 2015. After increasing oil imports earlier in the year to add to its SPR reserves, Chinese imports have since settled at around 5.6mn b/d, down from highs of 6.7mn b/d in April 2014. Chinese demand could increase once again if the country resumes filling up its SPR.

Non-OPEC supply (yoy growth, mn b/d) - 2014

Region	OPEC	IEA	Natixis
North America	+1.31	+1.35	+1.1
OECD Europe	-0.03	-0.04	+0.07
South America	+0.15	+0.11	0
Africa	+0.05	+0.05	+0.08
FSU	+0.01	-0.01	+0.05
Net growth	+1.5	+1.58	+1.25

Sources : Natixis, IEA, OPEC

Non-OPEC supply (yoy growth, mn b/d) - 2015

Region	OPEC	IEA	Natixis
North America	+1.06	+0.86	+1.15
OECD Europe	-0.02	-0.01	+0.06
South America	+0.2	+0.21	+0.1
Africa	-0.03	0	+0.01
FSU	-0.05	-0.12	-0.07
Net growth	+1.27	+1.2	+1.3

Sources : Natixis, IEA, OPEC

Global demand (yoy growth, mn b/d) - 2014

Region	OPEC	IEA	Natixis
OECD	-0.14	-0.18	-0.2
China	+0.32	+0.29	+0.1
LatAm	+0.23	+0.17	+0.17
Other Asia (Incl. India)	+0.23	+0.34	+0.27
Middle East	+0.31	+0.22	+0.22
Net growth	+1.1	+1.05	+0.9

Sources : Natixis, IEA, OPEC

Global demand (yoy growth, mn b/d) - 2015

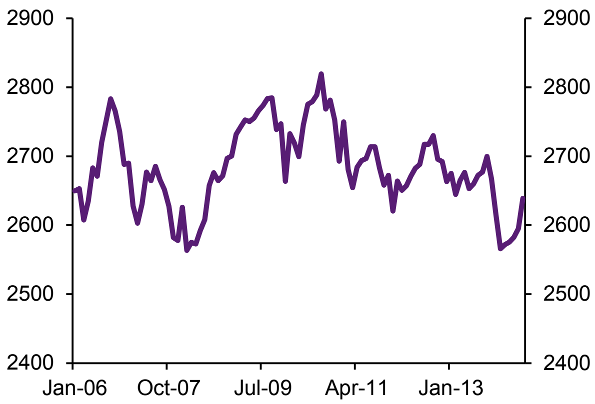
Region	OPEC	IEA	Natixis
OECD	+0.04	-0.11	-0.01
China	+0.31	+0.39	+0.3
LatAm	+0.23	+0.14	+0.17
Other Asia (Incl. India)	+0.23	+0.39	+0.27
Middle East	+0.29	+0.25	+0.20
Net growth	+1.21	+1.32	+1.2

Sources : Natixis, IEA, OPEC

European demand has been weak so far in 2014, despite showing some signs of improvement during the second half of last year. Refineries in the EU have been processing reduced volumes of crude this year (-600,000b/d from Jan-May on a yoy basis). European demand this year is expected to remain weak during the second half of the year, especially with the on-going deterioration in economic conditions in core EU countries. In 2015, European demand is expected to stabilise due to recovery in the global economy.

These forecasts for supply and demand imply excess crude of around 350,000b/d during 2014, pushing the expected daily call on OPEC output to somewhere around 29.5mn b/d. Non-OPEC supply is then expected to outpace growth in global demand by a further 100,000b/d in 2015. The excess supply is already contributing to an increase in crude oil stockpiles, particularly in the US and Europe. According to IEA, overall OECD oil stocks (including oil products and crude) were up for the 6th consecutive month in June 2014, leaving them 105mn bbl higher than end-2013 (up 10mn bbl yoy).

OECD Industry total oil stocks (mn bbl)



Sources : Natixis, Bloomberg, IEA

Geopolitics have played a significant role in influencing Brent prices since the Arab Spring in 2011. In 2014, the three most important focal points have been Iraq, Libya and Russia/Ukraine. For now, the situation in Ukraine poses only a limited threat to oil markets as the principal risk is the threat that Russia might cut off natural gas supplies in retaliation for EU/US economic sanctions. Were the situation to escalate further, this could bring into play the possible sequestration of western assets, such as BP's 19.75% stake in Rosneft. Rosneft produced around 4.2mn b/d in 2013.

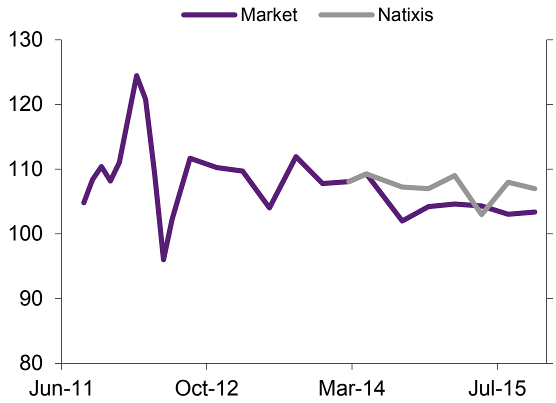
Libya continues to be a persistent threat to oil prices as Brent is particularly sensitive to Libyan oil disruptions. Libyan crude is of a similar quality to Brent, and many southern European refiners will take this crude if it is available to them. The absence of Libyan crude has therefore contributed to shortages in the Brent market and a persistent backwardation. Now that Libyan oil flows have resumed, we can expect Brent to come under pressure. The political crisis in Libya is far from being resolved on a permanent basis, hence we would expect Libya to contribute sporadically to Brent risk premiums.

The expansion in Iraqi oil output has radically reshaped OPEC dynamics over the past few years, helped by the continuing development of the country's export infrastructure. While Iraq's oil exports had been disrupted for some time by political disputes between Baghdad and the Kurdish Regional Government and sabotage of the key Kirkuk-Ceyhan pipeline, the level of threat escalated sharply this year following the incursion of ISIS into broad swathes of north-west Iraq. While the threat to KRG output is a relatively limited one as the bulk of Iraqi oil is produced the south of the country, were the country to fall apart or southern Iraq fall under ISIS control, it could have a catastrophic impact on oil prices.

Concerns over Iran have taken a back seat for now, indeed there seems to be some progress in talks between Iran and the P5+1 countries over the country's nuclear ambitions.

However, Iran could once again move back into focus in November 2014, when the extension period for the nuclear talks expires. On the one hand, if the talks were to fail, we would expect oil exports from Iran to come under renewed pressure from the US and Europe. On the other hand, a breakthrough in the talks could lead to an increase in Iranian oil exports, which would put additional downward pressure on Brent prices in 2015

Brent price outlook - futures vs Natixis forecast ($/bbl)



Sources : Natixis, Bloomberg

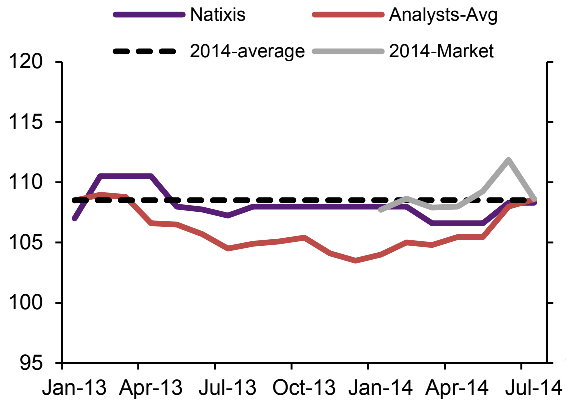
Due to the widening gap between global demand and non-OPEC supplies, we would expect Saudi Arabia to take the lead in reducing output during 2014H2 due to the decline in the expected daily call on OPEC. Against this backdrop, with geopolitical risks to crude supplies expected to remain contained, we would expect Brent prices to average $107.9/bbl in 2014.

In 2015, we would expect the gap between growth in global demand and growth in non-OPEC supplies to diminish. This would allow oil prices to stay more or less unchanged from 2014.

If Iranian oil were to come back online next year due to a deal between P5+1 countries and Iran, we would expect oil prices to drop below 2014 prices. Nevertheless, we do not anticipate oil prices falling significantly below 2014 levels as we would expect OPEC, and the swing producer Saudi Arabia in particular, to reduce production from their current high levels to ensure oil prices remained well above the $100/bbl "floor" within their $100-$100/bbl target range. Changes in the OPEC quota could be implemented at the December meeting if tensions in the Middle East were to ease, but this seems unlikely given the current elevated tensions across the region.

For 2015, we would expect Brent prices to average $106.7/bbl.

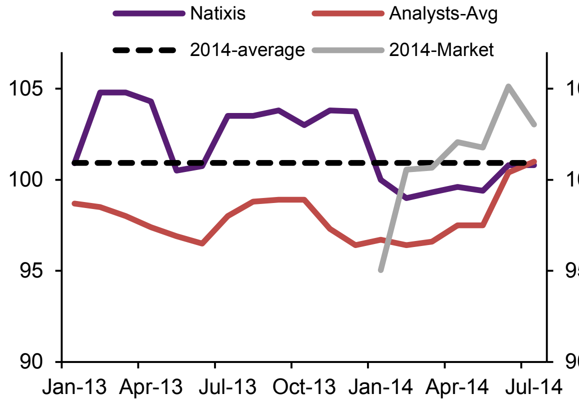
2014-Brent forecast vs market ($/bbl)



Sources: Natixis, Bloomberg, Reuters

Note: Reuters data is based on data obtained from approximately 25 analysts

2014-WTI forecast vs market ($/bbl)



Sources: Natixis, Bloomberg, Reuters

Note: Reuters data is based on data obtained from approximately 25 analysts

Spread between Brent and WTI

On the one hand Brent is expected to come under pressure in 2014 and potentially even in 2015 and on the other hand, WTI is expected to receive limited support from potential increase in US condensates exports and as US refineries process record volumes almost year round to supply oil products to feed not just increasing domestic demand but increased demand from Europe, Latin America and even Asia. This should help keep the Brent-WTI arb at around $4-6/bbl for the year as a whole.

However, we do expect significant fluctuations in these arbs due to new factors such as pipelines coming online in 2014H2 that will increase inbound flows of crude to Cushing by up to 800,000b/d. This could potentially help widen the spreads between Brent-WTI due to stock build-up at Cushing, which is still considered as the pricing point even though bulk of

refineries are in the GC and more of the displaced crude from Cushing has moved to the Gulf Coast.

The spread between Brent-WTI could narrow further if the US lifts its ban on crude exports or permits more widespread exports of lightly-processed crude such as condensates.

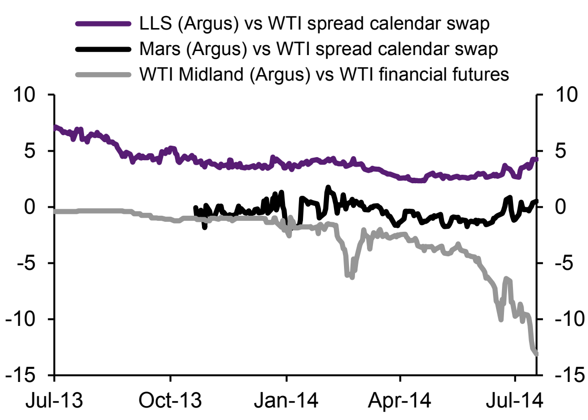
Spread between other North American crude grades and WTI

Brent-WTI-LLS triangle: LLS prices have been closely aligned with Brent prices for a long period due to the sea-borne arbitrage between the two grades. While Brent flowed into the USGC, LLS prices exceeded Brent prices. Now that flows of light crude are beginning to reverse, Brent is priced above LLS.

With the addition of new transportation infrastructure bringing more mid-continent crude to USGC, there has been a steady increase in crude inventories on the Gulf Coast. This has created a new risk that unwanted surpluses could now begin to occur on the USGC. Such temporary surpluses could result from unexpected outages at USGC refineries. There is therefore the potential for spreads to widen occasionally, driving LLS prices temporarily to more significant discounts versus Brent. In late-2013, for example, LLS's discount to Brent briefly exceeded $15/bbl.

While Cushing represented the principal choke-point in the US oil transportation network, surpluses of US crude resulted in occasional sharp declines in WTI prices versus sea-borne USGC blends such as LLS. Now that new pipelines have been constructed which reduce the surplus of crude in Cushing, bringing more crude to the USGC, there is a growing risk that future US crude surpluses will show up first as weakness in LLS prices, before a back-up of crude at Cushing subsequently impacts WTI prices as well.

North American regional light crudes spreads vs WTI ($/bbl)



Sources: Natixis, Bloomberg, Nymex

Conversely, unexpected pipeline outages reducing crude flows to the USGC, or a reduction in imports, eg caused by Gulf of Mexico hurricanes, could quickly result in spikes in LLS prices as refiners run short of crude.

WTI Midland vs WTI Cushing: WTI midland is land-locked and hence its spread versus WTI is also compromised. There are ongoing downside risks to oil prices in local regions around the Permian basin due to increases in crude output in the near term as horizontal drilling will increase output faster than traditional vertical drilling. Bridgetex pipeline coming online might only reduce that temporarily.

WCS-WTI: With only a limited increase in take-away capacity, the discount of WCS to WTI is expected to decline marginally from highs of $21.2/bbl in 2013Q4 to somewhere around $18.5/bbl by the end of 2014.

Liquidity in the markets: Liquidity of other regional markers remains a big question mark. It could increase as the growing heterogeneity of the US market forces producers, refiners and consumers to hedge more actively across regional blends until US oil infrastructure is fully developed.

Brent and WTI forward curves

The shape of the Brent forward curve has been inextricably linked to the fate of Libyan crude output, in large part due to the historical reliance of southern European refiners upon Libyan crude. In response to the loss of Libyan crude during the Arab Spring, the Brent curve moved into backwardation in early-2011. It remained in backwardation until July 2014, when Libyan output began flowing back into the global oil market.

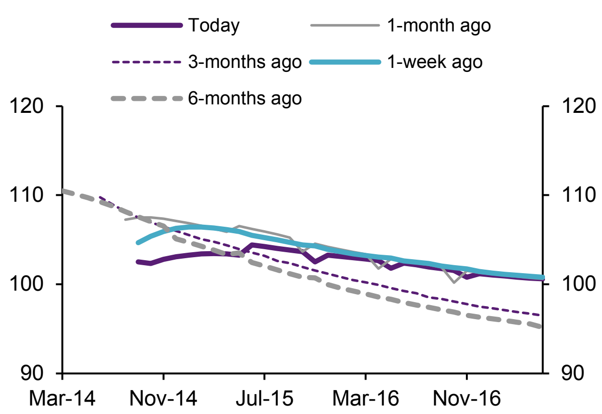
Other important factors are also at work. Over the past few years, US imports of west African crude have progressively declined as local supplies of light crude have expanded rapidly. The resultant surplus of west African crude has therefore come to play an increasingly important role in satisfying any shortage of European crude.

After many years of steady declines in North Sea output, the recent increase in investment in new fields, especially in Norway, has resulted in a yoy rise in North Sea crude supply during 2014H1. Volumes of Ekofisk have also contributed to this rise in North Sea output. Going hand in hand with this increase in North Sea crude supply, European refiners have continued to reduce capacity utilisation rates in response to poor demand and low profitability, thereby reducing demand for European crude.

Investors have benefited handsomely from the persistent backwardation in Brent prices over the past few years. While spot Brent prices have gradually declined since their early-2011 peak, positive roll returns have added a further 16% to spot returns out to their peak in 2014Q2. With Brent flipping from backwardation into contango, it would be

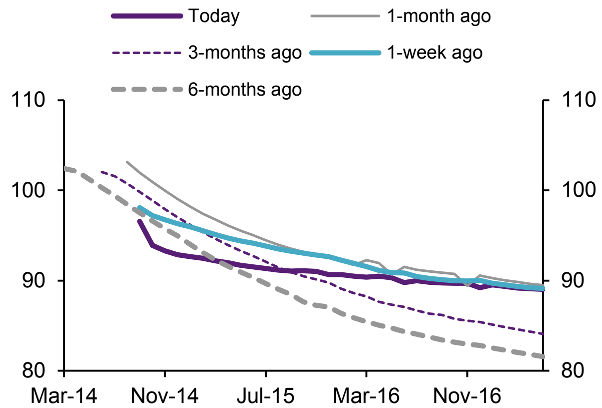
reasonable to assume that investors will have relinquished much of their previous long positions, helping to accentuate the move further into contango.

Brent forward prices ($/bbl)



Sources: Natixis, Bloomberg

WTI forward prices ($/bbl)



Sources: Natixis, Bloomberg

Will Brent remain in contango? This will depend on a number of factors. Libyan crude output and exports may be recovering, but the political situation in the country remains extremely tense. There is therefore plenty of scope for Libyan exports to drop once again at some point in the coming months.

North Sea supplies have suffered significant unanticipated outages over recent years, especially during the summer months, with maintenance of ageing equipment often becoming delayed. Despite the rise in output during 2014H1, there remains the risk that supplies could once again be disrupted over the late summer period.

Geopolitical tensions in the Middle East and in Ukraine remain elevated. So far, these have had very little impact upon crude output, but if this situation were to change, Brent prices would be likely to benefit, with spot prices likely to outperform.

WTI's backwardation is more interesting. In a market so well supplied with light oil, WTI's backwardation is most likely explained by the market perception that drawdowns in Cushing might reduce inventories to levels that risk compromising deliverability into near-term futures contracts.

While outflows have certainly risen as Cushing take-away capacity has increased, the addition of new pipelines bringing more crude to Cushing could soon reverse these flows. There is also the prospect that a build-up of crude on the US Gulf Coast could soon lead to oil backing up in Cushing as pipeline flows from Cushing to the USGC are forced to scale back.

Volatility

In the period prior to 2011's Arab Spring, the OPEC cartel functioned as a collective unit, adjusting output by increasing or decreasing their individual quotas. This political process was slow, typically timed to coincide with regular OPEC meetings, and hence OPEC behaviour tended to be reactive. A build-up of surpluses or deficits was common, resulting in oil prices overshooting either on the upside or downside. This price-adjustment process changed fundamentally in 2011. After the Arab Spring, destabilisation of OPEC member states meant that negotiation of individual quotas was no longer practical. The subsequent tightening of sanctions upon Iran further escalated tensions between OPEC members, with some increasing output in order to offset the forcible reduction in Iranian exports. With Iraqi crude output expected to increase rapidly, there was a reluctance on the part of Iraqi leaders to constrain future output via individual quotas.

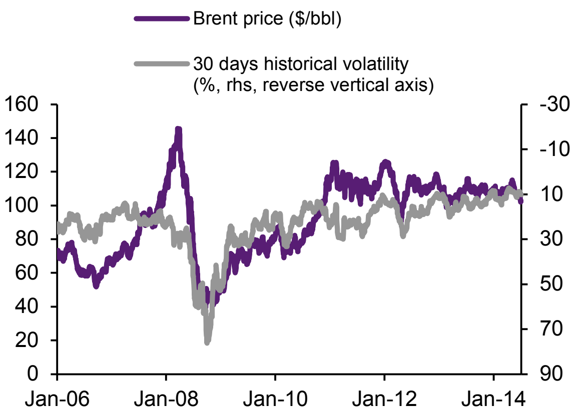
Far from exacerbating price volatility, this process led to a more stable price environment. Saudi Arabia, already implicit leaders of the cartel, took a more prominent, pro-active role, adjusting output themselves when it was perceived to be necessary in order to stabilise the global market.

Over the past four years, oil price volatility has been steadily crushed by Saudi Arabia's success in maintaining crude prices within their desired range of $100-110/bbl. Even as geopolitical tensions have escalated throughout the Middle East, oil prices have remained remarkably stable.

The fall in oil price volatility has had other causes as well. Rapid escalation in Chinese demand was in part responsible for the sharp acceleration in oil prices in 2007-08. Since

then, China has become more pro-active in sourcing additional supplies of energy and raw materials, ensuring that continued economic growth has not had an excessive effect upon global prices of those commodities.

Brent price and volatility



Sources: Natixis, Bloomberg

The upside in oil prices has also been heavily constrained by the rapid acceleration in North American crude supply. In 2007-08, the market was concerned that OPEC spare capacity would prove insufficient to meet the growth in global demand. Since then, non-OPEC supply has increased rapidly, led by the US, relieving this concern.

With Saudi Arabia supporting prices, US output capping prices and growth in Chinese demand more pro-actively sourced, crude prices have traded in a narrow range since 2011. As a result, price volatility has been steadily crushed. What are the risks that crude prices may once again break out of OPEC's target $100-110/bbl range? Although unlikely, there are a range of scenarios that could cause prices to deviate from their recent narrow range:

Escalation of tensions in the Middle East. The situation in Libya remains extremely uncertain, highlighting the possibility of another sharp drop in Libyan output. Despite the return of US support, Iraq is at risk of either ISIS incursions to the south and/or a total disintegration of the country's political leadership. If P5+1 negotiations with Iran were to fail, this would raise the prospect of a further tightening of economic sanctions by US and Europe.

Loss of Russian crude. Western sanctions are not intended to affect Russian near-term crude output, but their effect could still be felt, particularly if the situation in Ukraine were to deteriorate further. Amid a withdrawal of credit from western banks and financial markets, Russian oil companies could turn east, accepting credit in exchange for greater volumes of Russian crude.

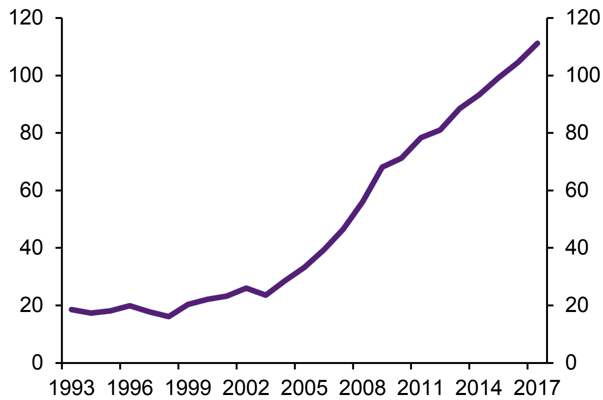
Political crisis in another OPEC producer. The situation in Venezuela continues to deteriorate. Elections in Nigeria in 2015 could precipitate a political crisis.

Exports of US crude. The US is gradually inching towards opening up its crude supplies to overseas markets. By permitting exports of stabilised condensates and output from splitter refineries, US authorities have taken two small steps closer to repealing their current ban on exports of crude.

Diminution of political tensions in the Middle East. A return to full capacity by MENA oil producers would add significant volumes of oil to the global market, led by Iran, Libya and Iraq.

Escalation of fiscal break-even oil prices across OPEC producers. Rising populations, rising incomes and growing domestic demand for crude are all pushing fiscal break-evens inexorably higher. Saudi break-evens remain below their target oil price range for now, but this situation will not last forever.

Weighted average oil breakeven ($/bbl)



Sources: Natixis

Notes: Weighted according to crude oil exports by Saudi Arabia, Iran, Iraq, UAE and Kuwait

For our forecast horizon, we continue to believe that Saudi Arabia will be able to maintain prices within their target range. Were any of these higher risk scenarios to play out, however, volatility could increase significantly.

In the world of low volatility that has persisted since 2011, markets have become increasingly vulnerable to a rise in price volatility. Producers and consumers have become more reluctant to hedge. Market participants have employed short volatility strategies as a means of increasing returns. Any break-out from the recent range could therefore result in a sharp overshoot as markets readjusted to this entrenched positioning.

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