Oil & gas macro outlook

Ukraine supports prices for now

Oil & gas

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The trend in international oil prices has been less than robust in early 2014 but firmer than fundamentals might have suggested. Once again, the explanation is geopolitical developments, with Ukraine very much to the fore of late (see pg 6). The Ukraine crisis, however, is unlikely to intensify to the extent necessary to disrupt Russian exports. Neither Russia nor the west could afford such a cataclysmic event, although it is possible that a low-level crisis over Ukraine lingers for some time. We continue to believe that the medium-term outlook is bearish for oil, reflecting burgeoning non-OPEC supplies, the upward trend in Iraq production and likely modest demand growth. A key area of medium-term uncertainty relates to the response of OPEC to rising non-OPEC and Iraqi output.

Supply/demand: Non-OPEC supply surge continues

In the first quarter of 2014 non-OPEC supplies continued to grow strongly, propelled by North America. Based on IEA data, non-OPEC production in March was up almost 2mmb/d on a year earlier. This easily more than offset a near 1mmb/d drop in OPEC output. OPEC output in the first quarter of 2014 was probably close to the seasonal 'call'. Overall for 2014, non-OPEC supplies, including OPEC natural gas liquids (NGLs), which are not subject to quota, could increase by about 1.8mmb/d. This should comfortably exceed demand growth globally, which will probably be 1.2-1.4mmb/d. For 2015 we continue to look for non-OPEC growth, including OPEC NGLs, of 1.5-1.6mmb/d and global demand growth of another 1.2-1.4mmb/d. Demand growth expectations are being dampened by technological advances, plus a slowing economy and growing environmental concerns in China.

Light crude spreads: WTI discount narrows sharply

WTI performed strongly relative to Brent in the early months of 2014, resulting in a sharp narrowing of the spread. By mid-April the WTI discount to Brent was down to $3.75/barrel after having approached $20/barrel in late November 2013. The extent of the narrowing was surprising given the heavy Gulf Coast inventory build-up. The key drivers were a sharp decline in inventory at the Cushing tank farm, buoyant US domestic refining activity and several bearish factors influencing Brent, including lacklustre light crude demand in the eastern Atlantic Basin, a slowing Chinese economy and the potential for a resumption of Libyan exports. We expect the WTI discount to widen over the balance of 2014 to about $9/barrel to more accurately reflect transportation costs and to take into account record Gulf Coast inventories. By late April the WTI discount was approaching this level.

Price forecasts: Brent and WTI upgraded

We are upgrading our forecasts for Brent and WTI for 2014 to reflect more robust price trends in the early months of the year, and the emergence of the Ukraine crisis. Although we do not expect Russian exports to be interrupted, the crisis heightens the market's perception of risk. Brent has been raised from $103.0 to $105.4/barrel while WTI increases from $94.0 to $96.3/barrel. For 2015, we are also raising price forecasts mainly reflecting positive carryover influences from 2014. Brent rises from $98.0 to $99.5/barrel and WTI from $89.5 to $91.0/barrel.

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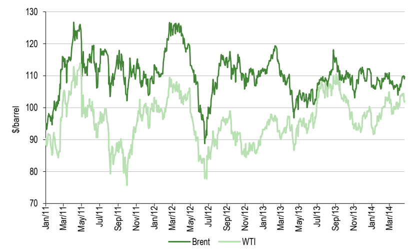
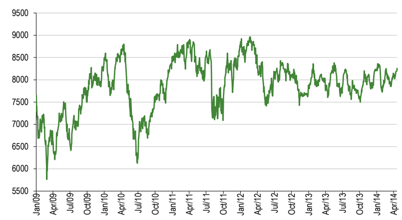
WTI vs Brent



S&P 500 Oil & Gas Index

FTSE 350 Oil & Gas Index



Source: Bloomberg

	WTI $/bbl	Brent $/bbl	Henry Hub $/mmBtu
2011	94.9	110.0	4.00
2012	94.2	112.0	2.75
2013	98.0	108.8	3.73
2014e	96.3	105.4	4.53
2015e	91.0	99.5	4.33

Note: Prices are yearly averages.

Contents

Highlights

- International light crude prices trended broadly flat while WTI firmed in early 2014.
- Oil prices firm in late April on Ukraine concerns.
- Russia petroleum exports to Europe are substantial at 4.3mmb/d (44% of imports and 32% of demand) and cannot be easily substituted.
- Conversely Russia is dependent on oil exports to Europe.
- Non-OPEC production growth remains robust.
- Continuing very strong production trends in the US and Canada.
- OPEC production remains around the 'call'.
- Iraqi production in February at a 35-year high.
- The key wildcard for 2014/15 is OPEC production.
- US demand trend has remained firm in early 2014.
- Gulf Coast crude inventories reach record levels.
- Non-OPEC output growth should comfortably exceed global demand gains in 2014/15.
- WTI has moved into backwardation for the front month despite Gulf Coast build-up.
- WTI discount narrowed sharply in the early months of 2014 as Cushing inventories declined.
- LLS Gulf Coast benchmark remained at a significant discount to Brent in Q114 rather than the traditional premium.
- Bakken discount to WTI narrowed sharply between Q413 and Q114.
- New $1.6bn Vaca Muerta exploration and development agreement between YPF and Chevron.
- 2014 and 2015 Brent and WTI price forecasts.
- Attractive Bakken economics at a price of around $100/barrel.
- Gulf Coast crack spreads firmed in Q114 driven by rising product prices.
- US natural gas and natural gas production trended higher in early 2014 despite harsh weather conditions.
- US natural gas demand boosted in Q114 by seasonally cold weather in the Midwest and eastern seaboard.
- US natural gas inventories were seasonally low in early April.
- US LNG exports scheduled to commence in 2016 but short term will not be significant internationally.
- US dry gas and NGL prices surge in Q1 driven by rising demand and tightening markets. Subsequently price gains partly reversed.
- US rig count climbs in early 2014 to a record driven by oil applications. Dry gas drilling continues to fall.
- US Henry Hub price forecast for 2014 upgraded reflecting a strong Q1 and the tightening inventory backdrop.
- Comfortable cash contribution at Henry Hub price but fully accounted returns still modest even for low-cost dry gas producers.
- US wet-gas producers very comfortably profitable at fully accounted level.
- Russia and Europe are also interdependent for the moment in terms of gas. Gas imports from Russia account for around 30% of European consumption.
- Flat to down trend in the FTSE 350 Oil & Gas Index so far in 2014.
- Weak trend in the AIM juniors continues.
- Strong performance by the US exploration and production stocks in 2014 year to date.

Executive summary

Recent oil price developments: In early 2014 Brent has trended broadly flat while WTI has firmed. Brent was trading at about $108.5/barrel in late April, which was in line with the 2013 fourth quarter average. On the same comparison WTI has climbed $4.9/barrel. Sentiment in Brent has tended to be dampened by the continuing evidence of a well-supplied market in the eastern Atlantic Basin, further signs of a slowing Chinese economy and optimism that Libyan exports will be resumed in the near future. For WTI the key drivers in early 2014 have been falling inventories at the Cushing tank farm and NYMEX pricing hub, and seasonally robust refining activity stemming from both firming domestic demand and buoyant exports. International light crude prices were apparently little affected by the Ukraine crisis until the second half of April. In early April Brent was actually trading $4.5/barrel below the 2013 fourth quarter average.

Russian petroleum exports: Russia is a major exporter of petroleum products to Europe. According to the IEA, net imports of petroleum products by OECD Europe in 2013 were 4.3mmb/d or 44% of the total. This was equivalent to 32% of OECD Europe petroleum demand. The loss of over 4mmb/d could not easily be made good in either the short or longer term by other regions. Exports of petroleum products to OECD Europe are also of paramount importance to Russia. The region accounted for 71% of crude oil and 36% of refined product exports in 2013.

WTI-Brent spread: The WTI discount to Brent narrowed consistently between end 2013 and early April but has subsequently widened. At the recent low the discount was $3.8/barrel, well down on the end December 2013 level of $12.4/barrel. By late April the discount had increased to $7.6/barrel reflecting a combination of the substantial inventory build-up along the Gulf Coast and growing concerns related to the Ukraine crisis. The former depressed WTI while the latter helped buoy Brent. We would expect WTI to trade at a discount to Brent within the range $6-12/barrel over the next year or two, with the core of this range determined by pipeline and rail transport costs from Cushing to the Gulf Coast.

LLS-Brent spread LLS, the Gulf Coast light crude benchmark, has swung sharply over the year or so from the traditional dollar or two premium to Brent to a significant discount. In late April the discount was running at about $6/barrel as the heavy inventory build-up along the Gulf Coast to record levels weighed on LLS and the Ukraine crisis supported sentiment in Brent. Long term, we expect LLS to trade at a structural discount of at least $2-3/barrel and possibly over $5/barrel.

Non-OPEC output: Non-OPEC crude oil output growth in 2014 has remained buoyant and is at or close to record levels. Compared with a year ago, first quarter output was probably up approaching 2mmb/d driven to a large degree by the US and Canada. In the absence of major outages, 2014 looks like being a very strong year for non-OPEC output growth. The EIA is looking for a gain of 1.8mmb/d or 3.3%, which will be the strongest performance since the early 1990s. Non-OPEC output should continue to grow robustly in 2015 and quite possibly over the balance of the decade. In 2015 the EIA is forecasting growth of 1.5mmb/d, driven once again by North America, but with a growing contribution from Brazil as new offshore fields are brought on-stream.

US output: Weather-related disruptions affected US production in late 2013 and the first quarter of 2014, but momentum has subsequently been regained. Taking the four weeks to 18 April, production based on EIA data was up 1.05mmb/d on a year earlier and was at a post first quarter 1988 high. Currently, total domestic supply of 11.8mmb/d, including natural gas liquids and renewables, may well make the US the world’s largest producer of liquid hydrocarbons. The EIA is forecasting US crude oil production of 8.54mmb/d (+12.6%) and 9.16mmb/d (+9.2%) respectively. These are slight downgrades from earlier in the year, reflecting development delays related to adverse weather conditions.

OPEC output: OPEC crude oil production was somewhat stronger than expected in the first quarter of 2014. For the period production is estimated by the EIA to have averaged 30.2mmb/d which was in line with OPEC's target and about a million barrels per day above the implied 'call'. Supporting OPEC output in the first quarter were continuing buoyant trends in Saudi Arabia, UAE and Kuwait and a strong showing by Iraq. Significantly Iraq boosted production between January and February by 0.5mmb/d to 3.6mmb/d, the highest level since the late 1970s. Iraq's target of 4mmb/d by end 2014 is arguably looking increasingly plausible.

Global demand: Global oil demand looks like showing modest growth in 2014/15 assuming macro-economic forecasts in line with the IMF's. According to the EIA, IEA and OPEC, demand growth globally in 2014 is likely to be within the range 1.14mmb/d to 1.40mmb/d or about 1.5%. For 2015 the EIA is forecasting growth of 1.37mmb/d. In the year to mid-April 2014, US demand has increased by about 1.0% year-on-year driven by distillates, kerosene and the large miscellaneous category. The largest product line, gasoline, has shown growth of 0.6%. On the demand front, the key story for US refineries remains exports. So far in 2014 these are up 22% on a year ago.

Oil supply/demand balance: We continue to expect non-OPEC controlled output growth to comfortably exceed global demand growth in 2014. The surplus could be about 0.5mmb/d assuming non-OPEC controlled output growth of 1.8mmb/d (including OPEC liquids) and an increase in demand of perhaps 1.3mmb/d. If OPEC output can be maintained at about 30mmb/d the overall global surplus could also be 0.5-0.6mmb/d in 2014. A high degree of uncertainty, however, surrounds the trend in OPEC output over the balance of the year. Based on the EIA's forecasts for non-OPEC controlled output and global demand growth, there would be a surplus of 0.1mmb/d in 2015.

Crude oil price forecasts: The fundamentals continue to point towards potential price weakness in both Brent and WTI. However, geopolitical factors have intervened to prevent the crystallisation of a weakening price trend. Reflecting the more robust price trends than expected earlier in the year plus the emergence of the Ukraine crisis, we are upgrading our 2014 forecasts for both Brent and WTI. The former has been increased from $103.0 to $105.4/barrel and the latter from $94.0 to $96.3/barrel. For 2015, forecasts have also been increased reflecting carryover influences with Brent rising from $98.0 to $99.5/barrel and WTI from $89.5 to $91.0/barrel.

US natural gas fundamentals: In early 2014 US trends in US production and consumption through October 2013 remained lacklustre, with the former depressed by scaled-back drilling activity and the latter a declining power station gas burn rate. Gas's competitiveness compared with coal was sharply eroded in 2013 by differential price movements. However, demand appears to have been given a significant boost in late 2013 and early 2014 by extreme cold in the principal gas-using regions of the Midwest and Northeast. Inventories have fallen sharply in recent weeks and are now below the seasonal average.

US natural gas prices: US natural gas prices were boosted in the first quarter of 2014 by harsh weather in the Midwest and eastern seaboard and a seasonally sharp drop in inventories. The Henry Hub benchmark hit a five-and-a-half-year high of $7.92/mmBtu in March 2014 but subsequently the price has fallen to about $4.6/mmBtu. In the light of the stronger than expected trend in the first quarter and the marked tightening in the inventory backdrop we are raising our 2014 Henry Hub price forecast to $4.53/mmBtu from $4.04/mmBtu previously. Positive carryover influences boost the 2015 forecast from $4.20/mmBtu to $4.36/mmBtu.

Russian gas exports to Europe: According to the EIA, Russia supplied about 5.7tcf of gas to Europe including Turkey in 2013. This was equivalent to 30% of consumption. Two key pipelines traversing Ukraine accounted in 2013 for 53% of Russian exports to Europe. Gazprom supplied gas to Europe in 2013 at an average $10.54/mmBtu, significantly below international LNG prices ranging from about $12.5 to $19/mmBtu. Near to medium term, Europe has no easily available alternatives to Russian gas at comparable prices. See section immediately following this summary.

Russian gas supplies to Europe

Logistical and pricing background: Russia accounts for 30% of European demand, Gazprom supplies at a considerable discount to international LNG prices

Historically, Russia has been a major gas supplier to Europe reflecting geographical proximity and a paucity of gas reserves in the latter. According to the EIA, Europe including Turkey, consumed 18.7 tcf of gas in 2013 of which around 30% or 5.7 tcf was supplied by Russia. There are various pipeline routes into Europe but the two major ones, Bratstvo and Soyuz, pass through Ukraine. A third pipeline, the Trans Balkan, supplies gas to Turkey and the Balkans. The EIA estimates that in 2013 the Ukraine was the transit route for 53% or 3.0 tcf of Russian gas exports to Europe. This in turn was equivalent to 16% of European consumption. The remainder of Russia's exports are shipped either via the Yamal pipeline through Belarus and Poland or the Nord Stream pipeline under the Baltic to Germany. Gazprom, the Russian state controlled gas producer, sold gas in Western Europe in 2013 at an average $10.54/mmBtu. The price is considerably below international LNG prices which range between about $12.5/mmBtu and $19/mmBtu. To these prices another $1/mmBtu or so would need to be added for re-gasification.

Presently, Europe accounts for the vast bulk of Russian gas exports. At current prices and volumes they generate approximately $60bn annually and account for roughly 12% of total Russian exports and not far off 10% of the federal budget. Clearly this is money Russia can ill afford to lose. In all likelihood Russia will announce a major move in May to diversify its gas exports when President Putin visits China. An agreement is expected to be signed calling for annual exports to China of 38bcm or 1.3 tcf of gas. This will involve constructing a pipeline from Western Siberia to north west China. Exports to China are not expected to begin in 2018 so in the short to medium Russia is locked into supplying Europe. Long term Russia will probably become considerably less dependent on gas exports to Europe than is presently the case.

Potential implications of the Ukraine crisis: Near term the key issue is the Gazprom payable, a cessation of Russian exports would send gas prices rocketing in Europe

The emergence of the Ukraine crisis in recent months has raised the spectre of a cut in Russian exports to Europe much as in 2009. The immediate issue concerns Ukraine's outstanding debt to Gazprom, which apparently is around $2bn. The fear is that Russia will attempt to enforce payment by shutting off the supply of gas to Ukraine and hence Europe. It should be noted, however, that President Putin has studiously avoided making an explicit threat along these lines. If Russian exports are halted through Ukraine, the issue then arises as to whether Europe could live with a 16% cut in gas supplies. The short answer is almost certainly 'no', particularly in winter. In all probability, however, in these circumstances, Russia might be prepared to supply extra gas via the Yamal and Nord Stream pipelines, thereby alleviating the problem. Any void remaining could possibly be filled by stepped-up LNG imports but at significantly higher cost. Note, there is no potential in Western Europe to boost gas supplies with the possible exception of Norway. In the event of disrupted supplies, the vulnerability for European consumers would clearly be a gas price surge in Europe along with spot shortages in those countries that are completely dependent on Russian supplies.

A more extreme scenario relates to a complete breakdown of relations between the west and Russia resulting in the cessation of all Russian gas exports. This would be a doomsday scenario that would send energy prices rocketing in Europe with highly negative consequences for the domestic economy. There would certainly be no easy way of offsetting the loss of almost 6tcf of gas imports from other sources either in Europe or outside without a substantial increase in prices. In the short term, one of the few measures that could be taken would be to greatly step-up coal-fired power generation. This would, of course, have highly negative implications for meeting the EU's cherished carbon emission targets, not only in the short term but quite possibly in the medium to long term.

Given the horrendous implications for both sides of a cessation or even a sustained cutback in Russian gas exports to Europe, we probably have to assume that a grand bargain will ultimately have to be struck over Ukraine between the west and Russia (probably involving the neutrality of Ukraine). Note, there are also considerable financial and reputational pressures on Russia to avoid a cessation or even a cut in gas exports to Europe. The working hypothesis probably has to be that Russian gas exports will continue uninterrupted in the near to medium term at least.

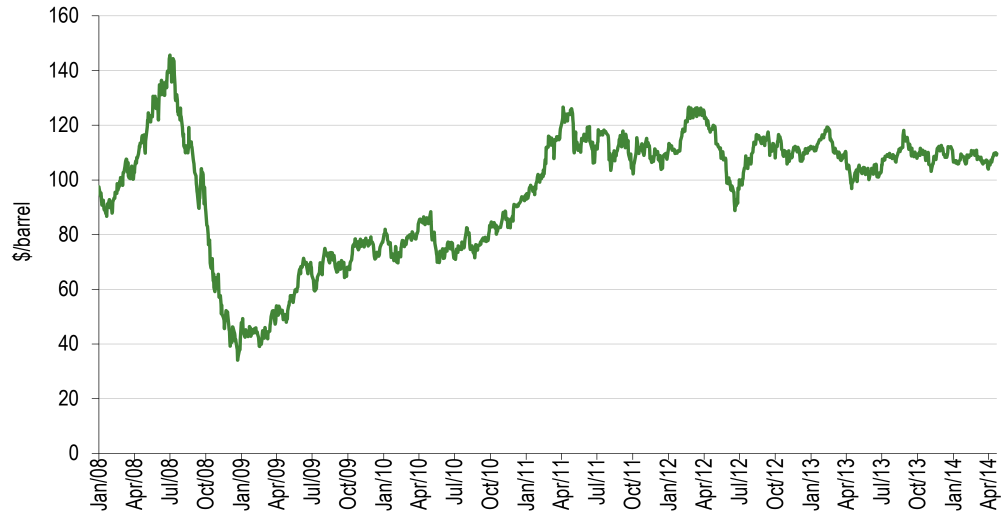
Crude oil market dynamics

Price overview

Market developments: Recent trends Brent flat WTI up

Recent months in retrospect: Between late December 2013 and late April 2014 international light crude oil prices trended broadly flat while WTI, the US benchmark, firmed. In late April Brent was trading at about $108.5/barrel, in line with the average for the fourth quarter of 2013, while WTI was around $102.5/barrel, up $4.9/barrel on the same comparison. As a result of the diverging trends, the WTI discount to Brent narrowed sharply from around $11/barrel in the fourth quarter of 2013 to $6/barrel. The underlying trends for both Brent and WTI have remained essentially flat since early 2011.

Exhibit 1: Brent crude oil price trend



Source: Bloomberg

The lacklustre trend in international oil prices in early 2014 continues a tendency that was apparent in the fourth quarter of 2013. Tending to dampen market sentiment have been: continuing evidence of a well-supplied market, further signs of a slowing Chinese economy, and growing optimism that exports will be resumed from Libya in the near future. The former reflects the continuing non-OPEC supply build-up driven by North America and what arguably has been a firmer trend in OPEC production than might have been expected. The surge in Iraqi output in February of 0.5mmb/d was particularly influential in terms of OPEC production.

For WTI the key drivers buoying prices in recent months have been twofold. First, US refinery activity was robust, reflecting both solid domestic product demand and a continuing strong trend in exports. Exceptionally cold conditions in the Midwest and along the eastern seaboard also probably boosted sentiment. Second, the sharp rundown in inventories at the Cushing, Oklahoma tank farm, the delivery point for Nymex crude. This reflected in part the start of operations at end January of the southern leg of the Keystone XL pipeline from Cushing to the Gulf Coast and in part buoyant refining activity stemming from rising demand.

Interestingly, international prices were little affected until the second half of April by geo-political factors in general and the Ukraine crisis in particular. It could, however, be argued that in the absence of Ukraine and the continuing constraint on exports from Libya due to the control of ports by rebel groups, the trend in Brent would have been significantly weaker than in the year-to-date. Interestingly in early April, Brent was trading about $4.5/barrel below the average for the fourth quarter of 2013.

Exhibit 2: WTI crude oil price trend

Source: Bloomberg

Regarding Ukraine, the market appears to have taken the position that the crisis is unlikely to intensify to the extent necessary to disrupt supplies of Russian exports. This conclusion is sound given the critical importance of oil exports to both Russia and Europe. According to the Economist Newspaper, oil and gas account for 70% of Russian exports totalling $515bn annually and contribute 52% to the federal budget. Despite the rhetoric, the Russian and European economies are in practice heavily interdependent, so it is extremely unlikely that any action will be taken to disrupt the flow of hydrocarbons by either party. We also believe it unlikely that supplies of oil along the southern spur of the Druzhba pipeline from Siberia to eastern Europe, which runs through Ukraine, will be interrupted this side of the apocalypse.

How large are Russian oil exports to Europe? According to the IEA (International Energy Agency), imports of Russian crude by OECD Europe in 2013 were 3.05mmb/d, equivalent to 36% of the total into the region. In addition, Russia is a sizeable supplier of refined product and natural gas liquids to Europe, although this is partly offset by exports from Europe, particularly of gasoline. Overall, according to the IEA, OECD Europe net petroleum imports from Russia in 2013 amounted to about 4.3mmb/d or 44% of the import total. This was in turn equivalent to 32% of OECD Europe petroleum demand in 2013. Eastern European states such as Hungary, Slovak Republic and Czech Republic are considerably more dependent on Russian supplies both of crude a refined product. The loss of 4.3mmb/d of petroleum imports could not be made good in the short or even the longer term by other regions and would clearly lead to a dramatic surge in prices with disastrous implications for the European economy.

Clearly, given the magnitude of shipments involved, OECD Europe is also of critical importance to Russia's petroleum industry. The region accounted for 71% of Russian crude oil and 36% of refined product exports in 2013 based on IEA data. Given the existing infrastructural links established to supply Europe, Russian producers would not be in a position to rapidly redirect their petroleum product exports to other parts of the world. In the long term we can, however, expect Russia to reorient its petroleum exports to areas outside Western Europe. Indeed, this process has already began with the completion of the Eastern Siberia-Pacific Ocean Pipeline in 2010. Russia now has the means to ship significant volumes of oil directly by pipeline to China and its Pacific coast. More oil could possibly also be shipped in due course from Black Sea ports to the Far East, although congestion through the Bosporus and Dardanelles might pose a constraint.

Supply-demand dynamics

Non-OPEC supply: Buoyant trend continues driven by North America

The buoyant trend in non-OPEC output in 2013 appears to have carried over into early 2014, although growth slowed sequentially reflecting weather related disruptions to development activity in the US. According to the IEA, output was running at 55.9mmb/d in February, which we believe was at or close to a record. Compared with a year earlier, output in the first quarter of 2014 was probably up almost 2mmb/d. As in 2013, growth continues to be driven largely by the US and Canada. Year-on-year gains in these two locations may have been around 1.18mmb/d and 0.25mmb/d respectively. Outside North America production trends were relatively stable in the first quarter of 2014. Outages continued in Syria and South Sudan due to civil wars, while there were technical issues constraining output in Brazil. Nevertheless, in the case of Brazil production firmed in February with a gain from the previous month of 2.2% to 2.61mmb/d, the highest level of output since the all-time peak of 2.64mmb/d in January 2012. Compared with a year previously, Brazilian production was up 4.6% for the month.

In the absence of major outages, 2014 still looks like being a very strong year for non-OPEC production growth. The EIA is currently looking for a gain of 1.8mmb/d or 3.3% to 55.8mmb/d. This is similar to the forecast at the end of 2013. The US is expected to contribute an incremental 1.0mmb/d and Canada 0.27mmb/d. Elsewhere, the major areas of strength look like being Brazil, China and Russia. Brazil should benefit from new offshore production, while Russia is expected to gain from field development, particularly in Eastern Siberia. The positives for China are expected to be the bringing back on-stream of the ConocoPhillips operated Peng Lai field in Bohai Bay and general development activity.

Key non-OPEC wildcards for 2014 are Sudan/South Sudan and the annual maintenance season in the North Sea. Assuming that the civil war can be wound down, the former could contribute an incremental 0.1mmb/d or so. Kazakhstan was until recently also a wildcard for 2014 but no longer is. The issue here concerned just how quickly the giant Kashagan field in the Caspian Sea could be brought back on-stream following the aborted start-up of operations in September 2013 stemming from a gas leak. In late April, the Kashagan consortium announced definitively that operations would not be resumed until late 2015 at the earliest, and quite possibly not until 2016. An investigation has revealed that around 200km of pipeline from the offshore production base to the onshore processing plant will have to be replaced. According to the consortium, a combination of faulty welding and corrosive toxic hydrogen sulphide gas (17% of the gas is H_2S) is the cause of the problem. To adequately combat H_2S corrosion the replacement pipe may well have to be manufactured out of costly nickel-intensive steel alloy. In the light of the gas leak issue and outage, expectations for production from Kashagan in 2014 have already been sharply downgraded in recent months. We believe, however, that confirmation of the outage for the whole year might adversely impact production in 2014 by 0.05mmb/d compared with earlier forecasts. The Kazakh authorities are suggesting that they are looking to boost production elsewhere to offset the impact of the Kashagan outage.

Non-OPEC production should continue to trend strongly upward in 2015 and indeed quite possibly over the balance of the decade. This is expected to be driven particularly by intensive development activity in the shale and tight reservoir formations of the US and Canada along with the oil sands of Alberta and the start-up of new Brazilian offshore fields. Medium term (post 2015) other key areas of production potential include Russia (East Siberia), Kazakhstan (Kashagan), West Africa and Latin America (shale development in Argentina and Colombia). The EIA is currently looking for oil production in 2015 of 57.3mmb/d, up 1.5mmb/d or 2.7% on the previous year. The key contributors to this growth are the US 0.9mmb/d, Canada 0.3mmb/d, Brazil 0.2mmb/d and Kazakhstan 0.1mmb/d. A downgrade may need to be made for Kazakhstan in the light of the recent Kashagan announcement.

OPEC supply: More buoyant than expected, Iraq hits a 35-year high

The trend in OPEC crude production was probably more buoyant than generally expected in the first quarter of 2014 and significantly, appears to have been at least in line if not in excess of the OPEC 'call' (world demand less non-OPEC supply and OPEC NGLs/non-conventionals). Production for the period was estimated by the EIA to have averaged 30.2mmb/d which was up 0.4mmb/d on the prior quarter although slightly down on a year earlier. Compared with the imputed call of about 29mmb/d, first quarter production may have been running around 1mmb/d higher. Buoying OPEC production during the first quarter were a surge in Iraqi output in February and continuing buoyant trends in Saudi Arabia, Kuwait and the UAE. In February Iraqi production, based on IEA data, surged by 0.5mmb/d to 3.62mmb/d (excludes about 240m b/d for Kurdistan), the highest level since the late 1970s. The surge was at variance with consensus opinion, which had grown increasingly bearish regarding Iraq's ability to significantly boost output in 2014.

The key positive for Iraqi production in February was the completion of the first stage of the upgrading of the export terminal facilities at Basra. Simultaneous dual loading is now possible at the two offshore mooring points, whereas only one had been usable previously. Work is expected to be completed on a third mooring terminal in the second half of 2014. Significantly, production capacity in southern Iraq is also being greatly expanded. In early April Lukoil brought on-stream its giant West Qurna-2 field ahead of schedule. This will initially produce at 0.12mmb/d but ultimately could produce over 1mmb/d. According to the IEA, capacity additions in southern Iraq will add more than 0.5mmb/d by 2014 year end. Iraqi government officials are looking for output to rise to 4mmb/d (up by about 30% year-on-year) by end 2014 and 9mmb/d by 2017. Arguably the former objective at least is looking increasingly plausible.

Libya currently continues to act as a constraint on OPEC production. During the first quarter petroleum industry activity virtually ground to a halt, reflecting the influence of armed militias blockading ports and production facilities in support of a variety of objectives, including secession. Production in March was a mere 0.15mmb/d or so which compares with sustainable capacity of at least 1.2mmb/d and probably closer to 1.6mmb/d. Discussions between the central government and the rebel militias in early April had been pointing to an accord which would allow the ports to be reopened. In the event of an accord, output could probably be boosted by about 0.6mmb/d within a week or so. This would, however, still be well short of the peak level of output prevailing of 1.4mmb/d before the port blockaded in the third quarter of 2013.

Even if there is no early resolution to the various disputes in Libya between disparate rebel groups and the central government, we see no vulnerability for oil supplies globally. This reflects the fact that OPEC production looks like being well underpinned for the foreseeable future at the target rate of 30mmb/d by rapidly rising Iraqi output and the buoyant trends in Saudi Arabia, Kuwait and UAE. From a wider perspective there is also the growth in non-OPEC supplies to consider.

An interesting issue for OPEC in the coming will be how it will respond to rising output in the non-OPEC world, Iraq and potentially Libya. The question is: will it cut production to accommodate the gains elsewhere, or will it tolerate weakening prices? The problem for OPEC would be compounded in the event of an accord in the coming months between Iran and the world's major powers relating to the former's nuclear programme and a relaxation or lifting of sanctions. Iran is currently producing 2.75mmb/d but has indicated that post an agreement it would be looking to boost output to its present sustainable capacity of approaching 4mmb/d. Interestingly Iran's exports (in part from floating storage) have been significantly stronger than expected in recent months.

Venezuela: In our last report we referred to the risk to oil production in Venezuela stemming from a potentially catastrophic deterioration in the economic and industrial backdrop related to the autarkic policies of the ruling socialist party. A particular concern related to the acute shortage of dollars and restrictions on imports of vital petroleum industry imports. In an attempt to alleviate the shortage of dollars President Maduro announced a currency reform package in March. This effectively introduces a legal quasi free market for obtaining dollars at rates below the black market rate of around 80 bolivars to the dollar but above the official rate of 6.3 bolivars. While the reform may alleviate the problem of the dollar shortage near term, it is far from being a long-term solution to an ailing economy. Growing civil unrest in the country and political polarisation is also a concern along with intensifying repression directed at leading opposition groups. There remains a possibility that in the coming months that political violence combined with import constraints may ultimately hit oil production. The risk of such a scenario has however probably declined since the currency reform.

Until now, at least, civil unrest in Venezuela does not appear to have greatly impacted the petroleum industry. Production, however, has been on a downward trend since the middle 2000s following a protracted strike in 2003, which ultimately precipitated the exodus of skilled technical and administrative manpower and the imposition by the then President Hugo Chavez of increasingly severe capital constraints and exchange controls. Between the mid-2000s and 2013 Venezuelan production fell by about 0.8mmb/d to 2.5mmb/d. The trend has continued to weaken in early 2014 with a drop to 2.44mmb/d based on IEA data.

Global demand: No major changes, modest growth

The outlook for global oil demand in 2014/15 continues to point towards modest growth. According to the EIA, IEA and OPEC demand globally is likely to be within the range 1.14 to 1.40mmb/d in 2014 which equates to about 1.5%. For 2015 the EIA is forecasting growth of 1.37mmb/d. We continue to believe that gains in demand in line with the above are plausible based on the IMF's global economic growth forecasts. These call for gains in GDP of 3.7% and 3.9% in 2014 and 2015 respectively.

As has been the case for some time, oil consumption growth in 2014 is likely to be entirely attributable to the non-OECD world. Here, for example, the EIA is looking for a gain of 1.29mmb/d (+2.9%) while the OECD world shows a drop of 0.08mmb/d. Regionally, the key areas showing gains are expected to be China (+0.39mmb/d), Middle East (0.2mmb/d), Latin America (0.2mmb/d), FSU (0.2mmb/d) and Africa (0.2mmb/d). In the OECD, gains in the US and Canada are expected to slightly more than offset declines in Western Europe (0.06mmb/d) and Japan (0.013mmb/d). It should be noted here that projected growth in China is sharply lower than the average of about 0.7mmb/d between 2009 and 2012. This reflects a combination of a marked slowdown in the economy and fuel conservation and efficiency enhancement measures. For 2015 the EIA is forecasting growth of 1.33mmb/d (+2.9%) outside the OECD and a marginal gain of 0.05mmb/d in the OECD world.

So far in 2014 the key development on the global oil demand front has been the relatively buoyant trend in the US. This continues the pattern apparent in late 2013 and appears to have been driven of late by several factors. These include a strengthening economy, cold weather in much of the country which has boosted demand for heating oil and hydrocarbon liquids, notably propane, and an unexpected increase in highway travel. After declining by about 2mmb/d since 2006, OECD Europe may also be stabilising in tune with a firmer economy. Japan's consumption, however, looks like softening significantly in 2014 and 2015. This reflects plans to increase the power station natural gas burn rate and to bring back on line nuclear power plants idled in the wake of the Fukushima nuclear disaster of 2011. The EIA is forecasting declines in Japanese oil demand of 0.13mmb/d (-2.9%) and 0.16mmb/d (-3.6%) in 2014 and 2015 respectively.

Global supply/demand balance: Non-OPEC supplies should comfortably exceed global demand growth in 2014

The oil market globally in 2013 was broadly in balance taking into account both OPEC and non-OPEC supplies. The growth in non-OPEC output plus natural gas liquids of about 1.5mmb/d comfortably exceeded the increase in global demand of 1.2mmb/d, but the apparent surplus on this basis was roughly offset by the drop in OPEC production between 2012 and 2013. For 2014, abstracting from unplanned outages, the growth in non-OPEC production plus OPEC NGLs should comfortably exceed global demand growth. The surplus could be 0.5-0.6mmb/d, assuming the previously discussed gain in non-OPEC output of 1.8mmb/d, a further 0.1mmb/d for OPEC NGLs and demand growth of perhaps 1.3mmb/d. Based on the EIA's forecasts for output and demand, the surplus for 2015 would be 0.1-0.2mmb/d.

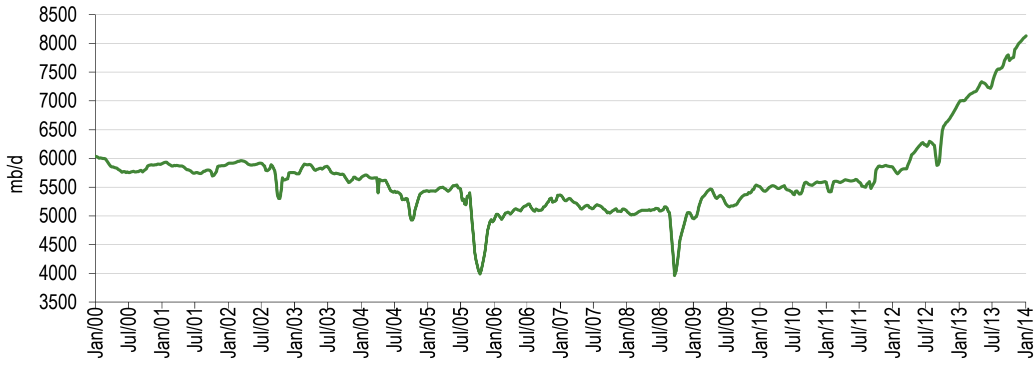
As always perhaps, the key issue surrounding the overall supply/demand balance is OPEC production. The situation is complicated on this front by the Libyan situation. As we have noted, however, we believe that OPEC production is comfortably underpinned at the target rate of about 30mmb/d in 2014 even if Libyan output remains largely shut-in by the ongoing stand-off between rebel groups and the central government. The reason is increasing Iraqi production and the continuing buoyant Saudi and UAE output trends. We therefore believe it entirely possible that the overall global surplus in 2014 could also be in the region of 0.5-0.6mmb/d. In fact, as we noted in our previous report, if Libyan production comes back on stream in a meaningful way in the coming months, and an accord is reached between the west and Iran over the latter's nuclear programme, the spectre of a significant and growing supply surplus could emerge in the second half of 2014.

US scene

Oil production and imports: Strong production trend in April

The trend in US crude oil production remained upward in the first quarter of 2014 but lost momentum early in the period due to the impact of severe winter weather in the Great Plains on well completion activity. Severe weather was particularly disruptive for logistics and fracking operations. Based on EIA data production in the four weeks to 28 March averaged 8.20 mmb/d. This was up by a modest (by the standards of recent years at least) 0.10mmb/d from end 2013 but still showed a gain of a hefty 1.04mmb/d or 14.6% from a year previously. In April the trend regained upward momentum. Production in the week ended 11 April came in a 8.30mmb/d, up 72,000b/d on the previous week and 1.09mmb/d or 15.6% on a year earlier. It was also the highest level of US output since the first quarter of 1988. Crude production averaged 8.23mmb/d and 8.27mmb/d in the four weeks to 11 April and 18 April respectively. The latter was up 1.05mmb/d or 14.6% on a year earlier.

Exhibit 3: US crude oil production



Source: EIA. Note: Data relate to four-week averages

Production continues to be driven by the development of the shale and tight reservoir formations of the Great Plains and Texas. In the four weeks to 18 April, US production of NGLs was also up year-on-year by 10.9% to 2.63mmb/d while renewables output showed a 9.9% gain to 0.98mmb/d. Total domestic supply of 11.88mmb/d in the four weeks to 18 April may well make the US the world's largest producer of liquid hydrocarbons.

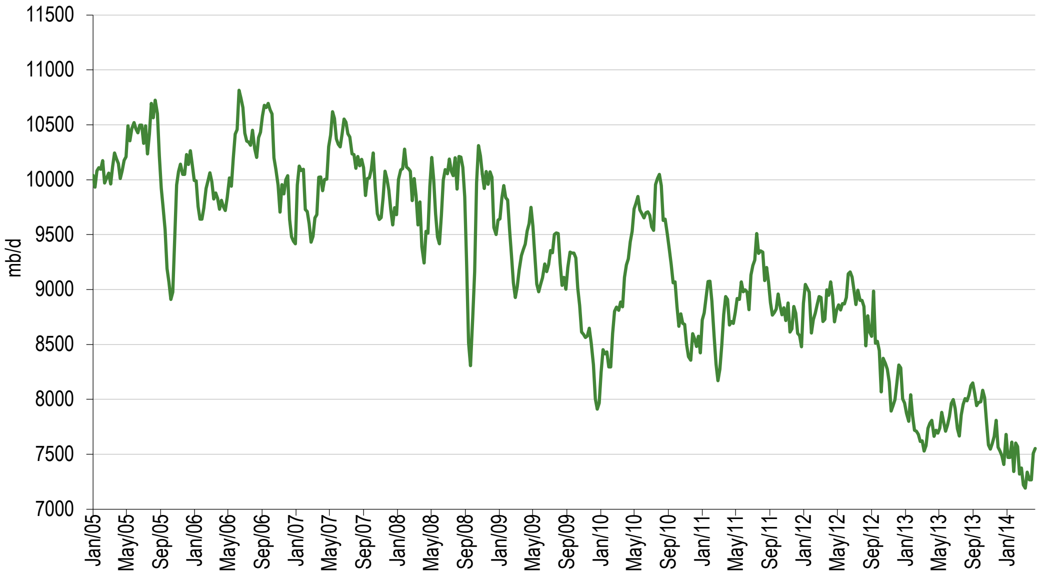
Reflecting the development delays of the first quarter, the EIA has recently downgraded its average US crude oil production forecast for 2014 from 8.54 b/d to 8.37mmb/d. The latter constitutes a 12.5% gain from 7.44mmb/d in 2013 and would be 67% above the 2008 low of 5.00mmb/d. Note, rising US output since the late 2000s has been despite falls in mature petroleum provinces notably Alaska, California and the Gulf of Mexico. The bulk of the gain in 2014 is expected to be driven by shale and tight reservoir formations plays but development activity in the Federal Gulf of Mexico should also make a contribution as eight projects are brought on-stream. Based on EIA data, production in 2014 is expected to be up by 0.88mmb/d and 0.09mmb/d in the Lower 48 states, and Federal Gulf of Mexico respectively while a further drop of 0.04mmb/d is expected in Alaska. The EIA is forecasting hydrocarbons liquids production in 2014 of 12.09mmb/d, equivalent to about 64% of US consumption. Given the recent strong upward trend, the EIA's 2014 production forecast could be on the conservative side.

For 2015 the EIA is looking for crude production of 9.13mmb/d, up 0.76mmb/d or 9.1% on a year previously. This is a slight downgrade on the earlier forecast of 9.29mmb/d. Shale plays will again be the key driver but further Gulf development activity should also play a part contributing 0.22mmb/d, according to the EIA. In 2016 crude production could be close to or exceed the 1970 record of 9.64mmb/d. Based on the EIA's long term forecasts, production growth in the second half of the current decade is expected to slow noticeably from the heady pace of recent years.

The key issues for the crude oil output trend medium term remain very high rates of depletion in shale wells post initial production and a potentially declining number of drilling opportunities in the more mature shale plays. It should be noted, however, that drilling and completion technology continues to advance, which is opening up new development opportunities in shale zones. It is quite possible that the conventional wisdom underestimates the potential of the shale revolution in the US. In this context it should be noted that the Bakken pioneer, Continental Resources, has fairly recently upgraded its estimate of recoverable reserves in the Bakken petroleum system reflecting an assessment of the deeper Three Forks formation. It now believes that the system hosts 32bn boe of recoverable reserves, assuming a 3.5% recovery rate against 24bn boe previously. At a 5% recovery rate, recoverable reserves could be 45bnboe, according to Continental. As the company has suggested, reserves of this magnitude would make the Bakken petroleum system one of the largest discoveries globally of the past 40 years.

Crude oil imports/exports: Reflecting rising domestic production, US crude imports have continued to trend down so far in 2014, although the rate of decline is less pronounced than the EIA expected at the beginning of the year. Taking the four weeks ended 11 April imports averaged 7.51mmb/d, down 3.9% on a year earlier and 30% on peak rates of 10.7mmb/d in 2005. The EIA is now suggesting imports of 6.97mmb/d for 2014 as a whole, down 0.63mmb/d or 8% on 2013 and the lowest level since 1992. A further decline of 0.63mmb/d to 6.30mmb/d is forecast for 2015.

Exhibit 4: US crude oil imports



Source: EIA. Note: Data relate to four-week averages

Exports of US crude have been largely prohibited since 1975. The prohibition was introduced to safeguard supplies on the domestic market following the Arab embargo and the subsequent surge in oil prices. In recent months some industry observers have suggested lifting the ban on exports partly due to the rapid tightening in light crude refining capacity in the US and partly as a means of offsetting the dependence of Europe on Russian supplies.

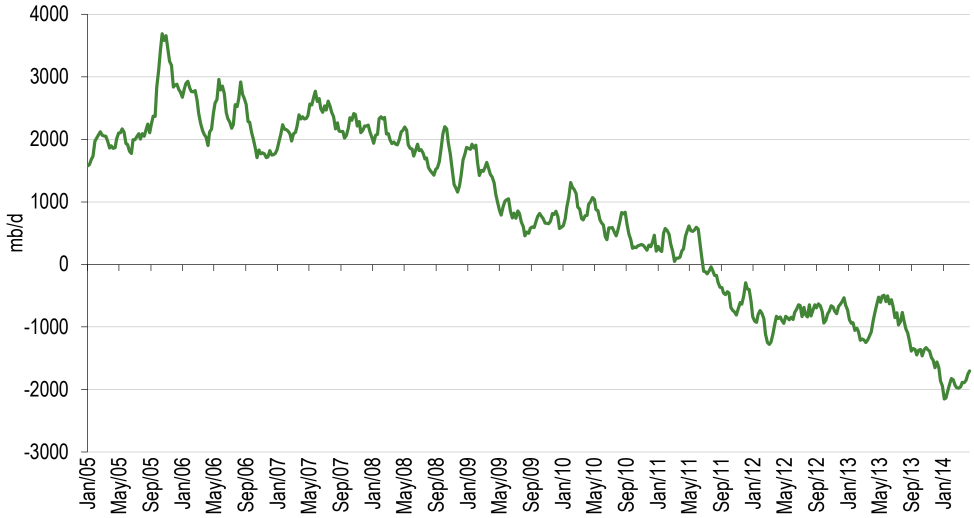
Regarding the first point, the argument is that as the refinery utilisation rate approaches 100% inventories will potentially build, thereby putting downward pressure on prices and discouraging upstream development activity. The counter-argument is that light refining capacity should be expanded to enable the influx of feedstock to be converted into refined products either for domestic or export markets. Indeed, to some extent the expansion of light crude refining capacity is already underway. Leading refiners, Marathon Petroleum and Valero Energy, for example, are both raising capacity and small topping refineries are being constructed in the Williston Basin to serve rapidly growing local needs for diesel and other distillates. The advantage of exporting refined product rather than crude is, of course, the greater value added as represented by the crack spread. Refined product prices may also be lower for the domestic consumer, thereby providing an extra stimulus for the economy. The US Gulf Coast is blessed as an export-oriented refining centre with some major competitive advantages including low cost feedstock and natural gas and proximity to markets. Arguably it should be prepared to exploit these advantages.

The geopolitical argument surrounding displacing Russian exports to Europe has recently come to the fore as the Ukraine crisis has intensified. We regard the case in favour of boosting US exports for this purpose as particularly weak. Firstly, there is nothing to stop Europe diversifying its sources of imports if it should so wish. The fact that Russia's weighting in the import mix is so high reflects geography and logistical costs. Alternative sources of supply in general and the US in particular are likely to be significantly higher cost on a delivered basis than those from Russia. Secondly, the US is still far from being self-sufficient in crude oil. Therefore any exports would have to be offset by higher imports to meet domestic consumption needs. Surely in these circumstances it would make more sense for Europe simply to import greater quantities from say West Africa or the Middle East.

Net product trade balance: Net export position continues to widen

The swing from a net import to a net export position in refined products has been one of the most dramatic developments in US petroleum industry circles in recent years. In early 2014 the net export balance continued to widen sharply, driven by both falling imports and rising exports. Taking the year to 11 April 2014, imports fell 9.2% from a year earlier while exports were up 21.7%. The net export balance averaged 1.75mmb/d in the four weeks to 11 April, against 0.90mmb/d a year previously and 1.40mmb/d in calendar 2013. For comparison, in 2005 net imports were running at a peak rate of 2.45mmb/d so there has been a swing since then of 4.20mmb/d.

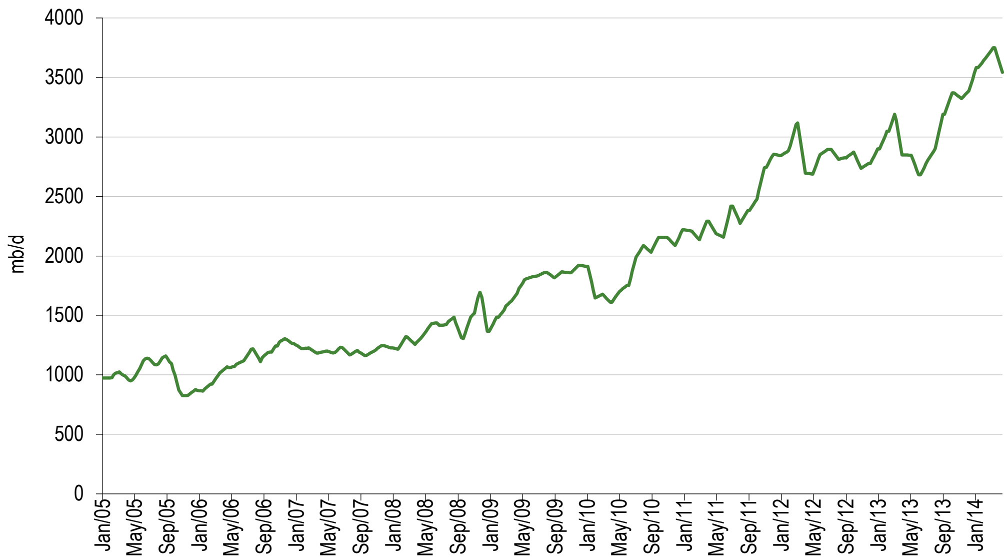
Exhibit 5: US net product imports



Source: EIA. Note: Data relate to four-week averages, negative recordings are net exports.

The continuing strong underlying trend in the net export balance reflects the US refining industry's powerful competitive position. This relates in large part to access to internationally competitive supplies of feedstock and natural gas (used both as a feedstock and fuel) and its proximity to buoyant markets, particularly in Latin America where the local refining industry is capacity constrained. The US Gulf refineries also tend to have the advantage of high middle distillate yields, the product line showing the strongest growth.

Exhibit 6: US petroleum product exports



Source: EIA. Note: Data relate to four-week averages

Texas: Closing in on the 1972 record of 3.4mmb/d

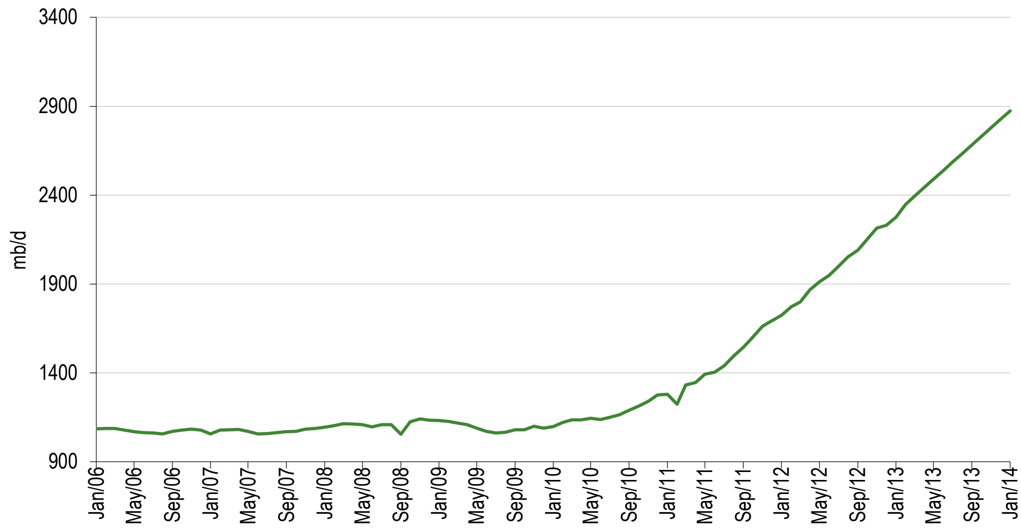
Texas crude oil production in 2013 averaged 2.56mmb/d, up 29% on a year previously and the highest level since the early 1980s. Compared with the 2007 low of 1.07mmb/d, production in 2013 was up 2.4 times. At end 2013 production was running at 2.83mmb/d and in January 2014, the most recent month for which EIA data is available, was 2.87mmb/d, up 26.3% on a year earlier. Texas is not only the largest oil producing state in the US but is also one of the of the world's leading oil producing provinces.

Texas production continues to be driven very much by the rapid development of the prolific Eagle Ford shale play in the Western Gulf Basin in the south west of the state. Based on EIA data, production there was approximately 1.2mmb/d at end 2013 and in April 2014 was probably approaching 1.4mmb/d. The recent rate of travel suggests that production could approach 1.7mmb/d at 2014 year end.

The Permian Basin, located in the west and northwest of Texas (also southeast New Mexico), is traditionally the largest oil producing zone in the state but has now probably been surpassed by Eagle Ford. It contains major tight reservoir stacked plays such as the Spraberry, Wolfcamp and Avalon/Bone Spring. The Cline is a recently identified tight play apparently offering considerable potential. At the end of 2013, according to the EIA, Permian production was about 1.4mmb/d of which possibly 0.3mmb/d was attributable to New Mexico. The Permian production trend has been more pedestrian of late than that of the Eagle Ford. Based on EIA reports, output in April might be around 1.45mmb/d.

Development potential in the Western Gulf and Permian basins points to the very real possibility that over the next two years the 1972 record for Texan production of 3.4mmb/d will be exceeded. Importantly, there is also believed to be major Eagle Ford development potential across the border in Mexico. Now that President Enrique Pena Nieto has lifted the more than seven-decade ban on foreign oil companies operating in Mexico, exploration activity could begin in earnest over the next few years.

Exhibit 7: Texas crude oil production



Source: EIA. Note: Data are monthly averages.

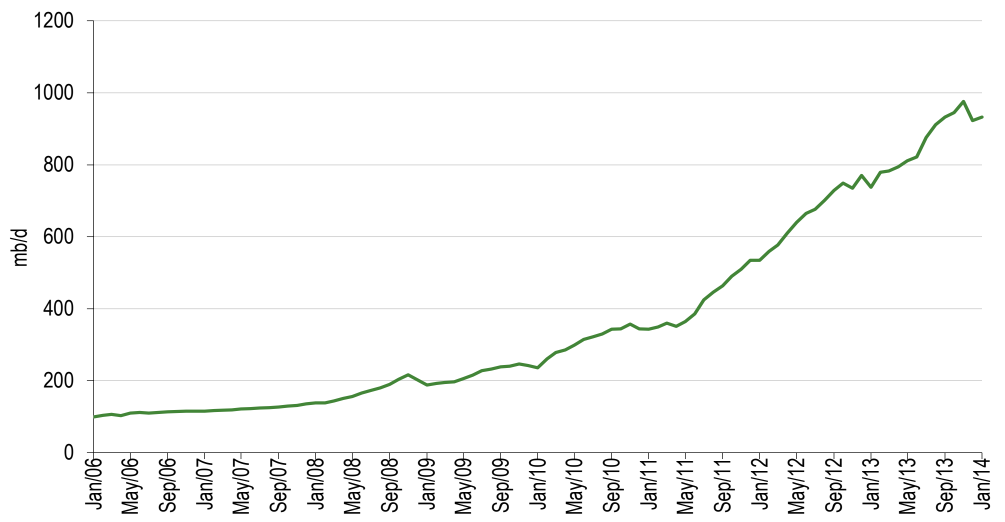
North Dakota: Production regaining upward momentum after a harsh winter

North Dakota crude oil production was heavily affected in December 2013 and to a lesser extent in the first quarter of 2014 by harsh weather conditions. Production in December slumped 53,000b/d from November's record of 976,000b/d. Nevertheless, such was the blistering pace of development earlier in the year, production still rose between 2012 and 2013 by 29% to 858,000b/d and was more than double the level of 2011. Significantly there was a partial recovery in January and February 2014 to 935,126b/d and 951,350b/d, which left production in February up 22% on a year earlier. In recent months around 93% of production in North Dakota has continued to be derived from the Bakken/Three Forks formation. Including Montana and South Dakota the Bakken petroleum system was producing around 1mmb/d for the first time in the fourth quarter of 2013. Interestingly, the wells in operation in the North Dakotan Bakken exceeded 10,000 for the first time late in 2013.

Adverse weather conditions depressed drilling activity in December but data released by the North Dakota Department of Mineral Resources (DMR) is pointing to a rebound in production in the months ahead. For example, wells spudded in January and February were 208 and 210 respectively, which is significantly above the monthly average in 2013 of 188, while development permits for the same months were in line with 2013. The January and February rig count of 189 was also in line with the 2013 trend.

In all likelihood, North Dakota crude oil production will exceed 1mmb/d during the second quarter of 2014. We believe the average production rate could be around 1.1mmb/d for the full year, which would be 28% above a year previously. The DMR has suggested that North Dakota production may reach 1.6mmb/d by mid-2017 based on the development of the Three Forks formation, and subject to certain caveats surrounding the regulatory environment, taxation and light crude refining capacity.

Exhibit 8: North Dakota crude oil production

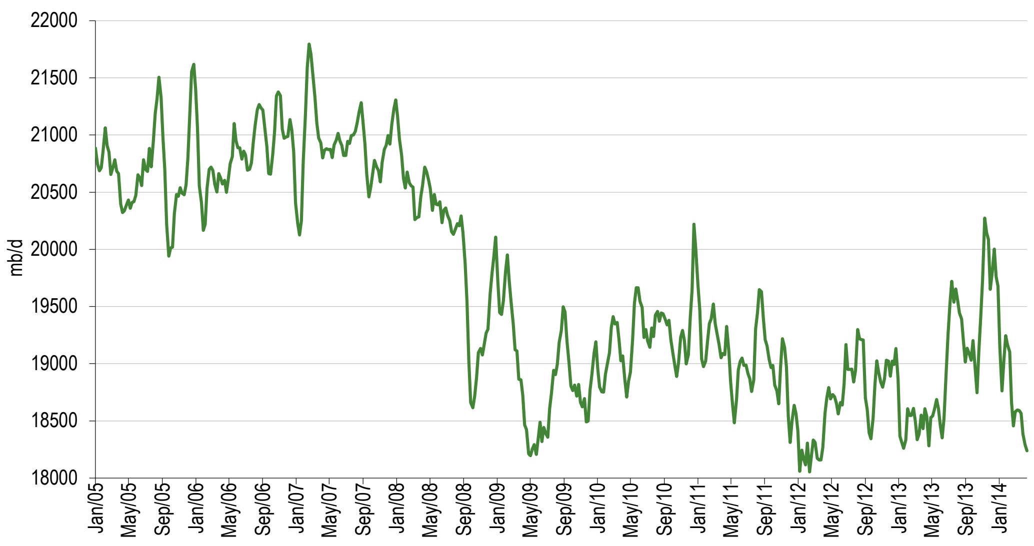


Source: EIA. Note: Data are monthly averages.

Domestic demand: Growing modestly

US domestic petroleum demand in the second half of 2013 strengthened noticeably even allowing for seasonality, driven by increasing highway travel and buoyant agricultural and chemical sector activity. The last two factors tended to boost demand for hydrocarbon gas liquids such as propane and ethane. Demand overall peaked out in the four weeks ending 15 November 2013 at 20.1mmb/d, a level that had not been seen since the first half of 2008. For 2013 as whole, US petroleum product demand grew by 2.2% to 18.89mmb/d. Abstracting from the economic recovery year of 2010, this was the first year of growth in demand since 2005. According to the EIA, the area of strongest growth in 2013 was hydrocarbon gas liquids, which showed a year-on-year gain of 6.4%. More modest gains were shown by gasoline and distillates at 1.1% and 2.5% respectively.

Exhibit 9: US petroleum product supplied

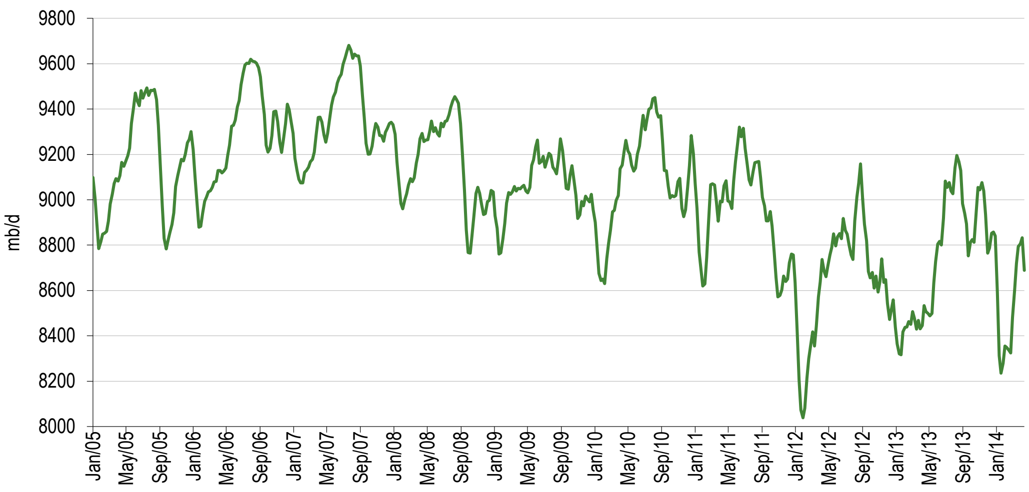


Source: EIA. Note: Data relate to four-week averages.

Largely in tune with the seasonal pattern, demand dipped sequentially in the first quarter of 2014. The average for the period was 18.74mmb/d, 1.5% above a year previously. Growth by product line was as follows: gasoline 0.4%, distillates 2.9%, kerosene 4.0%, residual fuel oil -15.9%, propane/propylene -11.1% and miscellaneous 9.6%. Interestingly, in the four-week period to 18 April the year-on-year growth rate actually turned negative to the tune of 1.6%. Gasoline, distillates and kerosene showed solid growth of 1.8%, 5.6% and 2.6% respectively but this was more than offset by declines of 36.4% for fuel oil, 22.8% for propane/propylene and 7.8% for miscellaneous. The reasons for these declines are not immediately apparent. Despite the softening trend over the past few weeks US demand was still up year-on-year by 1.0% in the year-to-date 18 April.

The EIA is still anticipating broadly unchanged petroleum product demand in 2014. In the light of the year-to-date trend, the relative buoyancy of the US economy and rising chemical industry activity we regard this forecast as conservative. Arguably, a modest gain of a per cent or so is more likely.

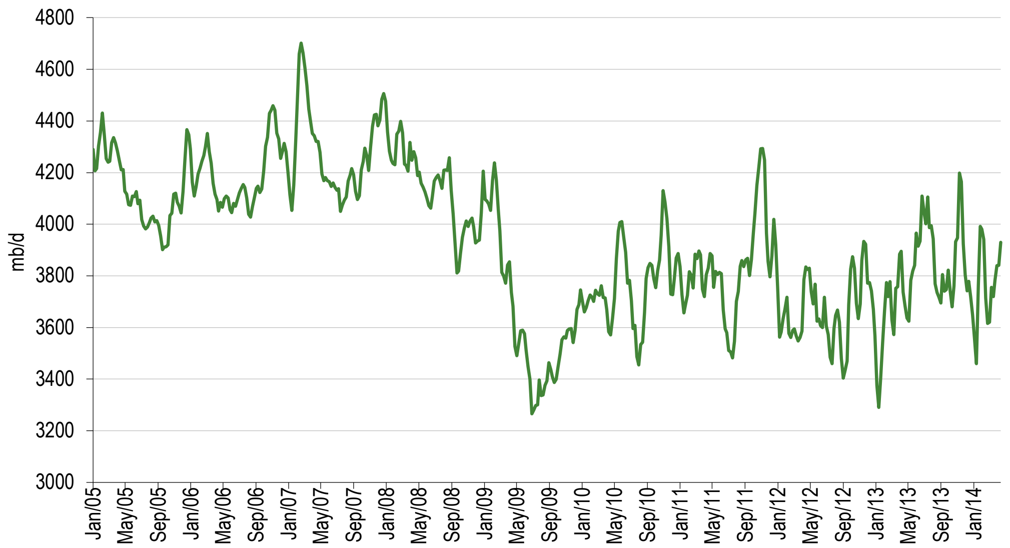
Exhibit 10: US gasoline supplied



Source: EIA. Note: Data relate to four week averages.

For 2015 the EIA's forecasts call for a marginal gain in demand of 0.5% to 18.99mmb/d led by distillates. Essentially flat demand in 2014/15 may appear at variance with the EIA's GDP growth assumptions of 2.5% and 3.2%. The explanation in large part reflects the improving fuel efficiency of the light vehicle and civil aircraft fleets and the EIA's assumption of a reversal of the recent increase in highway travel. What may have been underestimated is the impact of rising chemical industry feedstock demand. The agricultural sector is also a wildcard, particularly with regard to the use of propane in the drying of grain. Swings in vehicle use are, of course, difficult if not impossible to predict. In defence of the EIA's position; however, there has been a downward trend in miles driven in recent years.

Exhibit 11: US distillates supplied



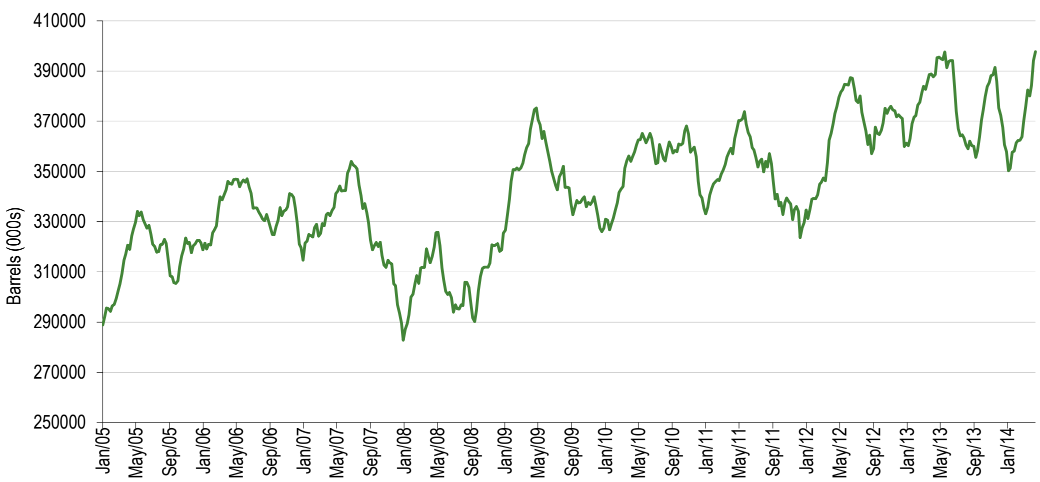
Source: EIA. Note: Data relate to four-week averages.

Inventories

Crude oil: Record levels

US commercial crude inventories have shown a sharper than normal seasonal climb in recent weeks and are at or close to record levels. Based on EIA data, crude inventories stood in the week ended 11 April 2014 at 394.1mm barrels. This was up 6.5mm barrels from a year earlier and 2.7mm barrels above the recent 22 November 2013 high. There was a further gain to 397.7mm barrels on 18 April which marginally exceeded the 24 May record of 397.6mm barrels. Significantly, seasonally high inventories have occurred despite relatively high refinery activity bearing in mind the time of year. Refinery runs, for example, in the latest four-week period, were 15.34mm barrels, up 2.1% and 5.8% on one and two years ago respectively. Based on the seasonal pattern US crude inventories could comfortably exceed 400mm barrels before showing the normal decline in the third quarter.

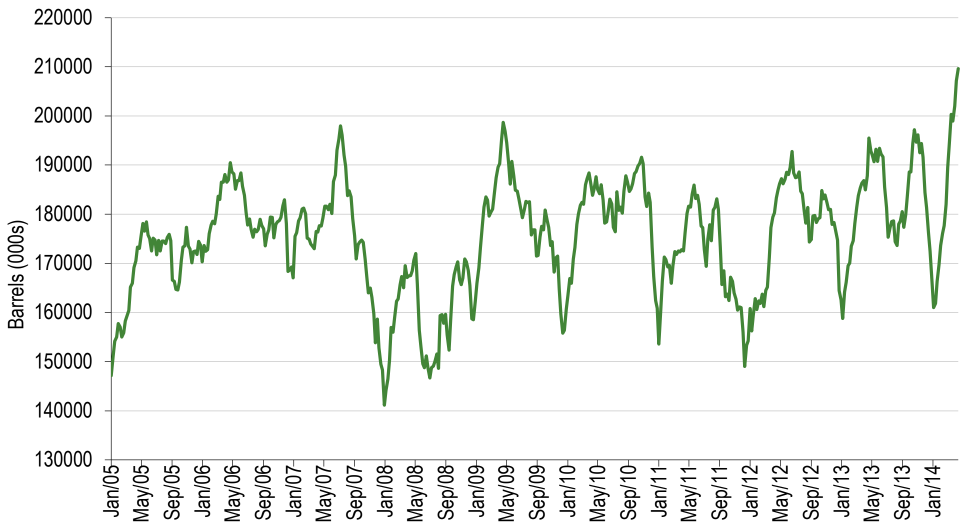
Exhibit 12: US crude oil inventory



Source: EIA

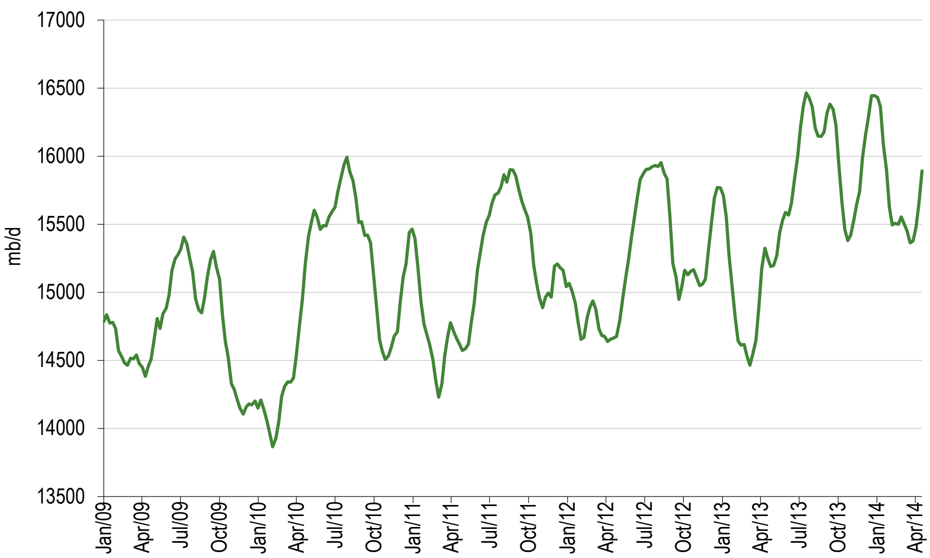
On a days' supply basis, crude inventories are very comfortable. On 11 April inventories were equivalent to 25.7 days' supply, which was similar to a year ago and close to the high end of the range based on the experience since 2000. Including the strategic petroleum reserve inventories on 11 April were 1089.2mm barrels, equivalent to about 71 days' supply.

Exhibit 13: Gulf Coast inventories



Source: EIA

Exhibit 14: US refinery runs



Source: EIA

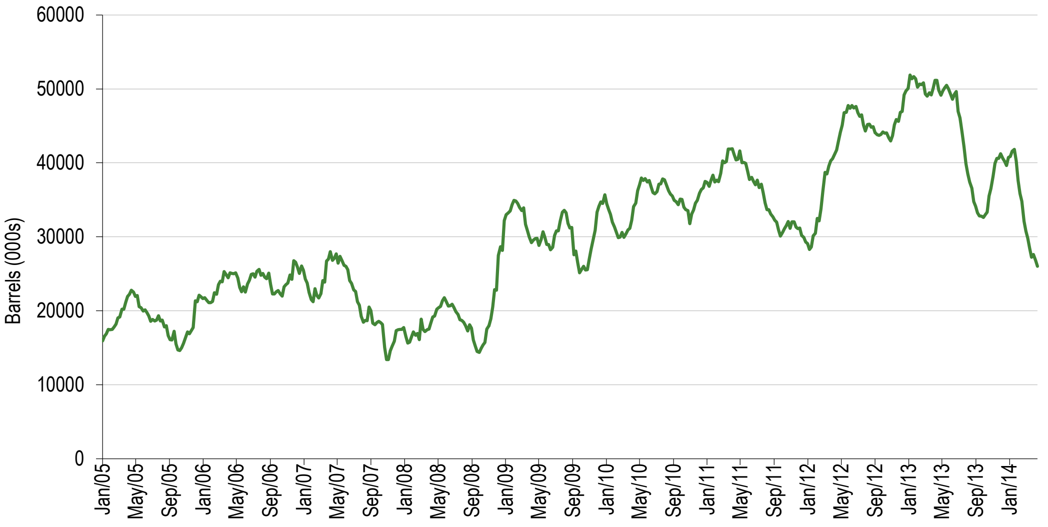
Cushing: Sharp fall since end 2013 but surplus merely shifted to the Gulf Coast

Crude inventories at the Cushing, Oklahoma tank farm, the delivery point for Nymex crude, started to trend down in earnest in the second half of 2013 from record levels of about 51mm barrels. After a brief upturn in late 2013 the trend subsequently has been decisively downward, which contrasts with the overall trend in the US. At 11 April 2014 inventories stood at 26.8mm barrels, down 12.8mm barrels or 32% on end 2013 levels and 47.5% on a year earlier. The sharp drop of late reflects the following:

- The start of operations on the southern leg of TransCanada's Keystone XL pipeline from Cushing to the Gulf Coast at the end of January.
- Relatively high refinery activity.
- Enhanced pipeline and rail infrastructure that has made it possible to bypass the Cushing tank farm.

Interestingly, despite the fall, Cushing's inventories are still slightly above the top end of the range prevailing between 2005 and 2008, which predated the surge in domestic production. To a large degree surplus inventory has simply moved from Cushing to the Gulf Coast. On 11 April crude inventories on the Gulf Coast were at record levels of 207.2mm barrels and were up 34.7mm or barrels or 20% from end 2013 and 22.2mm barrels or 12% from a year earlier.

Exhibit 15: Cushing crude oil inventories



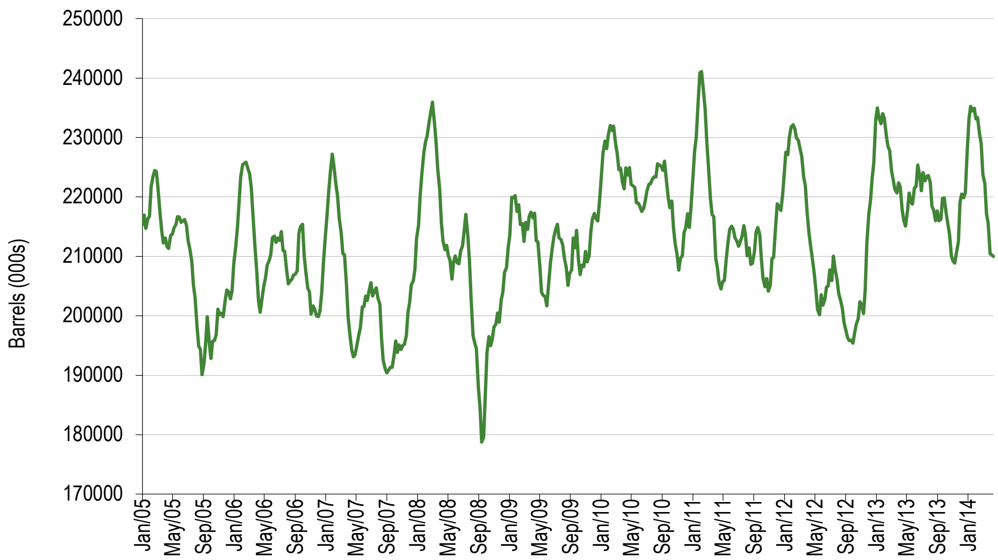
Source: EIA

Gasoline: Sharp fall in recent weeks but not unusually low from long-term perspective

US gasoline inventories have dropped sharply in recent weeks, taking them from the top end of the five-year range for the time of year at the beginning of 2014 to the lower end in early April. Based on EIA data for the week ending 11 April, inventories were 210.3mm barrels, down 11.4mm barrels or 5.2% on a year earlier and 25mm barrels or 10.6% on the recent January high. The steep fall in gasoline inventories reflects in part seasonal influences, and in part the firming trend in gasoline demand in 2014. It should be noted that from a longer-term perspective than the EIA's five-year seasonal range, gasoline inventories at around 210mm barrels are not unusually low.

On a days' supply basis, gasoline inventories have also fallen significantly of late. For the week ended 11 April inventories were equivalent to 23.8 days' supply, which compares with about 25 at the end of 2013 and 26.3 a year earlier. Although well below peak levels, the gasoline days' supply currently still look comfortable based on the experience since 2000.

Exhibit 16: US gasoline inventories

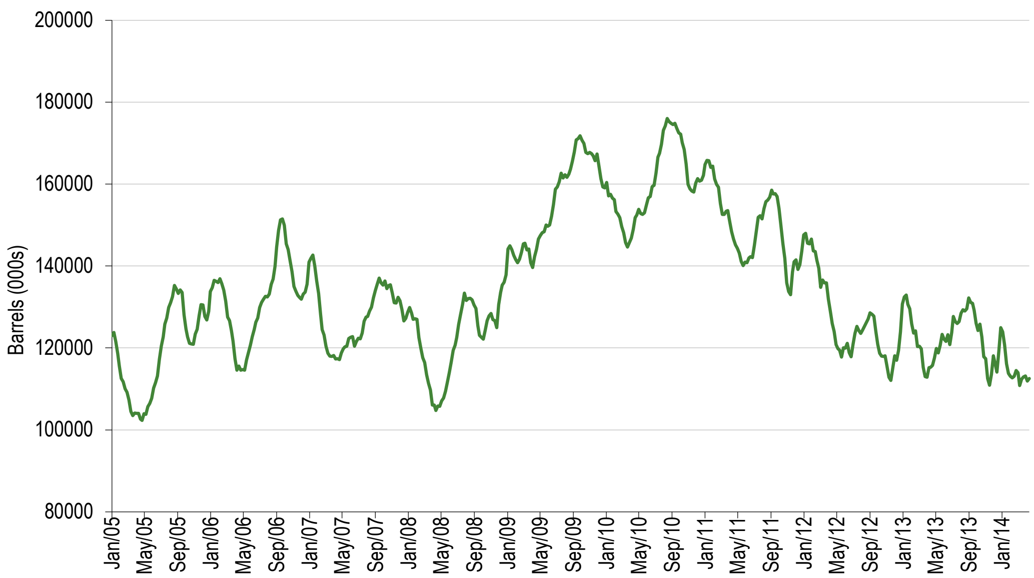


Source: EIA

Distillates: Downward trend possibly bottoming out

US distillate inventories have been under downward pressure since mid-2010 but may now be in the throes of bottoming out. Taking the week ending 11 April 2014 inventories stood at 111.9mm barrels, which was in line with the levels prevailing over the past two or so months. However, inventories at 11 April were 3.3mm barrels below a year earlier and were at the lower end of the seasonal range for the time of year. In the latest week, inventories were equivalent to 29.1 days' supply, slightly down from the 29.6 days of a year earlier. The days' outstanding remain well above the lows of about 22 days plumbed in the early to mid-2000s and are not abnormal from a long-term perspective. Days' outstanding at about 50 in 2009/10 were, by contrast, unusually high and a function of recessionary influences at the time.

Exhibit 17: US distillate inventories



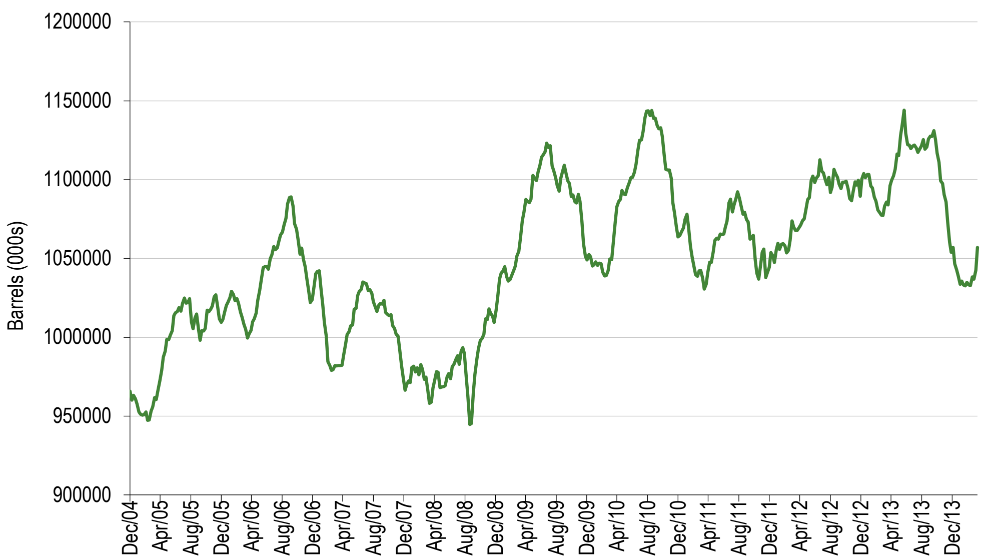
Source: EIA

We believe that to a considerable extent, the pressure on distillate inventories over the past few years has been due to a surge in distillate exports. Given that distillate exports tend to have higher crack spreads than domestic sales, there has been every incentive to pare inventories. The drop in inventories therefore probably has not been entirely involuntary. In the four-week period ending 11 April distillate exports were running at 1.18mm barrels (25% of production) slightly down on recent peak levels but up 39% on a year previously.

All petroleum products: Inventories remain historically high

In our view, the acid test concerning the adequacy of petroleum industry inventories is the all-encompassing definition including US commercial crude oil and refined product. Based on EIA data for 11 April, inventories on this basis stood at 1,056.9mm barrels. Inventories overall are down 87mm barrels or 8% from the peak level in 2013 of 1,144.0mm barrels but this was a post 2000 high and quite possibly a record. From a post 2000 perspective commercial inventories in total currently, in fact, remain historically high.

Exhibit 18: US all petroleum product inventories



Source: EIA

Argentina: Chevron likes what it sees

In our January report we discussed the shale oil/gas potential of Argentina and the backdrop to the local petroleum industry. Presently, Argentina has the world's largest and most advanced shale oil/gas development project outside North America. This revolves around the 30,000 square kilometre Jurassic/Cretaceous age Vaca Muerta formation located in the Neuquen Basin approximately 1,000-1,500 km south-west of Buenos Aires. The petroleum engineering consultancy, Ryder Scott, estimated recoverable resources at about 23bnboe in 2012 but there could be upside including the deeper Los Molles formation. Significantly, Vaca Muerta compares favourably with US counterparts such as the Eagle Ford in terms of key shale play quality parameters such as organic content, thickness and pressure. Production from the Vaca Muerta is currently estimated by industry sources at around 20,000boe/d. The bulk of this relates to concessions operated by state-controlled YPF. The YPF/Chevron joint venture has suggested that Vaca Muerta production could be up to about 80,000boe/d by 2017.

The key news item surrounding Vaca Muerta of late is the $1.6bn exploration and development agreement announced on 10 April between YPF and Chevron. This calls for both large-scale development in the Loma Campana concession (about 250km north-west of Neuquen city) and exploration in the Narambuena zone 100km north of Loma Campana. The new agreement is in addition to the $1.2bn Chevron financing announced in July for the Loma La Lata pilot project. Clearly, Chevron likes what it has seen so far both regarding Vaca Muerta and YPF as an operator. According to YPF/Chevron, the plan is to boost drilling in the Vaca Muerta in 2014 to 170 wells from the previous estimate of 140. The energy consultancy, Wood Mackenzie has recently suggested that about 200 shale wells will be drilled in the Vaca Muerta in 2014. YPF has indicated that the full-scale commercialisation of Loma Campana will necessitate drilling around 1,500 wells. Note that YPF has also recently raised $1bn in New York through a 10-year bond issue with an 8.75% coupon. The issue was 5x over-subscribed. YPF's ability to raise finance has been transformed since an agreement was finalised at the beginning of 2014 between the Argentine government and Repsol concerning compensation for the earlier expropriation of a 51% stake in the company. Its new-found ability to raise finance internationally has positive implications for Vaca Muerta development activity.

Another interesting development concerning Vaca Muerta has been the decision by Petrobras to abort an earlier plan to divest its upstream assets in Argentina. This appears to reflect in part the potential for shale development in the country. In February Petrobras announced what was apparently a significant discovery in the Vaca Muerta at Rincon de Aranda.

Vaca Muerte plays: YPF is possibly the most obvious but there are TSX and one AIM alternative

Arguably the most obvious way to play the Vaca Muerta story is through YPF itself. YPF has an ADR listed in New York and has a free float excluding the government and Repsol stakes of about 37%. The other principal ways of playing Vaca Muerta are through two TSX-listed juniors, Americas Petrogas and Madelena Energy, both of which have substantial operations in the Neuquen Basin and AIM/Buenos Aires-listed, Andes Energia. Americas Petrogas is largely focused on the Neuquen Basin and is probably the purest play on Vaca Muerta. It has joint ventures with ExxonMobil and now YPF following the latter's recent acquisition of Apache's operations in Argentina. Madelena has working interests in three large Neuquen blocks and is partnered with Apache/YPF and the Neuquen provincial government. It also has exploration interests in Alberta. Andes Energia has a strategic partnership with YPF in the Vaca Muerta and has E&P interests elsewhere in Argentina plus in Brazil, Colombia and Paraguay.

Light crude spreads

WTI-Brent: WTI discount narrows in early 2014 before widening modestly in late April

Between end 2013 and early April 2014 the WTI discount to Brent, which first became apparent on a sustained basis in the third quarter of 2010, narrowed pretty consistently. As of 11 April the discount had narrowed to $3.8/barrel, well down on the end December 2013 level of $12.4/barrel and indeed the recent November 2013 high of $19/barrel. The average discount for the first quarter of 2014 was $9.2/barrel against $10.9/barrel in the fourth quarter of 2013. In the third and fourth weeks of April the spread once again widened and at $7.6/barrel was around a one-month high.

The narrowing trend in 2014 is perhaps a little counter intuitive bearing in mind the continuing production build-up in the US Mid-Continent, record Gulf Coast inventories and lingering supply uncertainties and geopolitical concerns elsewhere in the world. In practice, however, WTI has been buoyed by:

- The sharp drop in inventories at Cushing, the NYMEX pricing point.
- Robust US refining activity reflecting both solid domestic and continuing strong export demand.
- Generally positive sentiment surrounding the direction of the US economy.

By contrast, sentiment surrounding Brent was subdued until late April. This reflected in part lacklustre light crude demand in the eastern Atlantic Basin and in part Brent's greater sensitivity to a slowing Chinese economy, relatively buoyant OPEC production and the potential for resumed Libyan exports. The widening of the WTI discount in late April was a reflection principally of the substantial Gulf Coast inventory build-up which weakened the former and growing concerns relating to the Ukraine crisis, which supported Brent.

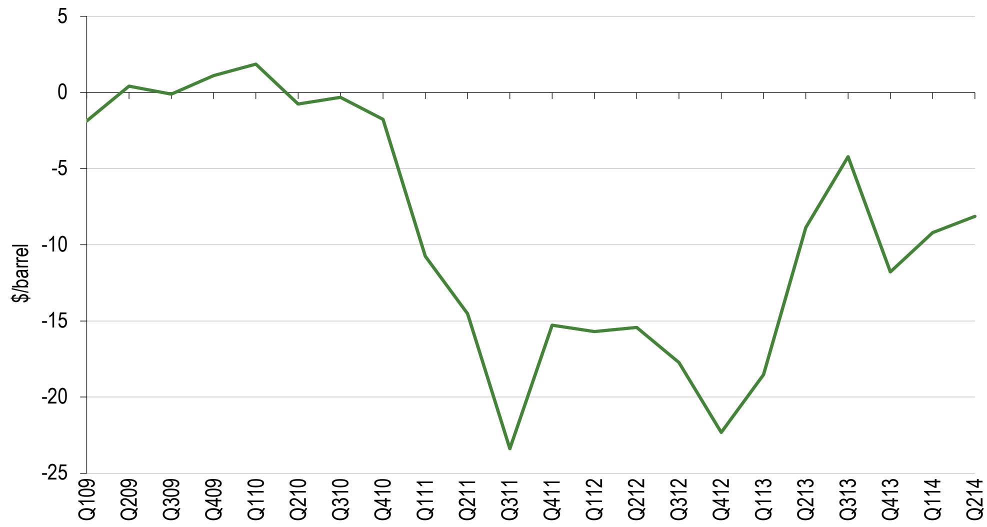
At just under $4/barrel the WTI discount in early April was slightly under pipeline costs for uncommitted shipments from Cushing to the Gulf Coast. Additionally it should be noted that not all oil is shipped from the Mid-Continent and Texas to the Gulf Coast by pipeline. In practice much is shipped by rail at a cost significantly in excess of $4/barrel and probably closer to $10/barrel. This might suggest a blended transportation cost of about $7/barrel. Conceptually this should also be the WTI discount to Brent, assuming the latter can be sold on the Gulf Coast. In practice a further $2-3/barrel may need to be added given the discount that Gulf-sourced light crudes such as LLS are now selling to Brent. Based on this analysis we would continue to expect WTI to trade at a structural discount to Brent within the range $6-12/barrel over the next year or two with the core of this range determined by transportation costs. As noted in our previous report, the precise discount will depend on a variety of factors including:

- The light oil supply-demand balance outside the US.
- Geopolitical developments.
- The strength of the upward trend in US Mid-Continent production.
- The availability of light oil refining capacity in the Mid-Continent and the Gulf Coast.
- The availability of pipeline and other takeaway capacity from the Mid-Continent, the Permian and Western Gulf Basins.

The above would suggest that at a discount of about $4/barrel WTI is uncompetitive vis-a-vis Brent for a Gulf Coast refinery, given that it is less than the average transportation cost from Cushing to the coast. A similar situation prevailed briefly in the third quarter of 2013 when the Brent discount virtually disappeared.

In the coming months we would expect the WTI discount to Brent to widen from recent levels to more accurately reflect inland transportation costs. A further factor concerns the build-up of inventory along the Gulf Coast. Following the realised discount of $9.21/barrel in the first quarter 2014 we look for WTI to trade at one of about $9/barrel over the balance of the year. For 2015 we would also look for a WTI discount averaging $9/barrel. This scenario is very similar to that given previously.

Exhibit 19: WTI-Brent spread



Source: Bloomberg

Exhibit 20: WTI 2009-15 quarterly prices ($/barrel)

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	62.0
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013	94.3	94.1	105.8	97.6	98.0
2014e	98.7	98.0	95.0	93.5	96.3
2015e	93.0	91.0	90.0	90.0	91.0

Source: Bloomberg and Edison Investment Research. Note: Q114 is an actual.

Exhibit 21: Brent 2009-15 quarterly prices ($/barrel)

	Q1	Q2	Q3	Q4	Average
2009	45.1	59.4	68.4	75.0	62.0
2010	76.8	78.6	76.4	86.9	79.7
2011	104.9	116.8	109.1	109.3	110.0
2012	118.7	108.7	109.8	110.9	112.0
2013	112.8	102.9	110.0	109.4	108.8
2014e	107.9	107.0	104.0	102.5	105.4
2015e	101.0	100.0	99.0	98.0	99.5

Source: Bloomberg and Edison Investment Research.

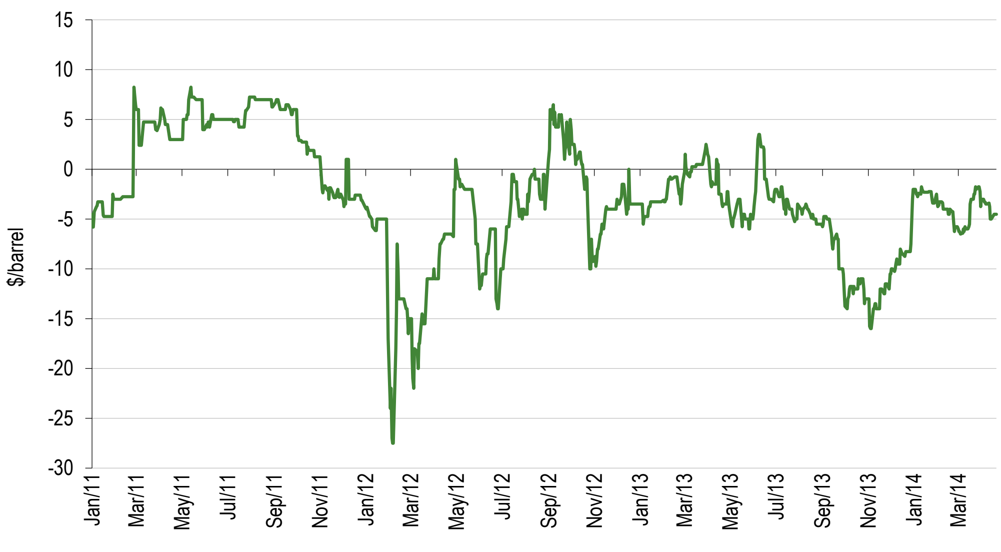
WTI Midland-Cushing spread: There are two pricing points for WTI, Cushing Oklahoma (30 miles west of Tulsa) and Midland, West Texas (300 miles west of Dallas and 400 miles south-west of Cushing). The former serves the Mid-Continent and the latter the Permian Basin. Historically, WTI has sold at a small discount of a dollar or less to WTI Cushing. At the end of 2013 the discount at $2.50/barrel was slightly above the historical norm. During the first quarter it widened and on 14 March reached a historically high $14.0/barrel. Subsequently a narrowing has taken place but the discount was still an unusually high $9/barrel or so in the third week of April. The widening trend during the first quarter appears to have reflected a combination of growing Permian production and tight pipeline capacity utilisation compounded by an outage.

Bakken-WTI: Bakken discount narrows in 2014 to normal levels

Bakken grade (Clearbrook Minnesota hub) has a broadly similar specification to WTI and is therefore a high quality light crude. With the exception of Tesoro’s modest Mandan 71mb/d facility near Bismark, North Dakota, there is currently no refinery capacity within close proximity to Bakken crude production. The bulk of Bakken output therefore has to be exported from the Williston Basin with a price point of Clearbrook, Minnesota. Bakken oil was initially mainly shipped either to Midwest and mountain state refineries, including four in Montana or to Cushing. Over the past two or so years, new markets have opened up on the eastern and western seaboards, as rail logistics have been upgraded. This has enabled Bakken producers to capture higher-priced markets leveraged to Brent and Alaska North Slope (ANS). Approximately 80% of Bakken crude is shipped by rail.

Historically, Bakken oil has sold at a discount of several dollars to WTI, although the market has in practice been highly volatile and at times premiums have been recorded. Volatility has reflected the potential for outages at a relatively small group of refineries plus, from time to time logistical disruptions. Since the advent of large scale shipments to the seaboards, the discount is also sensitive to swings in the WTI-Brent spread. In principle, for Bakken producers to be competitive in seaboard markets, Bakken grade oil broadly speaking needs to sell at a discount to ANS and Brent at least equivalent to rail costs. Based on Valero Energy data, the cost of railage from North Dakota to the Pacific Northwest is about $9/barrel (perhaps $15/barrel to Los Angeles), to the eastern seaboard $14-17/barrel and to the Gulf Coast $12/barrel. As far as Gulf Coast refineries are concerned, the differential may in practice need to be little larger given the discount to Brent that has recently emerged there for light crude. Clearly WTI can be used as the benchmark for shipments to upper Midwest refineries in Wisconsin and Minnesota along with the mountain state refineries and Tesoro's Mandan facility.

Exhibit 22: Bakken-WTI spread



Source: Bloomberg

Following a pronounced widening in the fourth quarter of 2013, which took the Bakken discount down to $16/barrel in November, a narrowing took place in the first quarter of 2014. On average Bakken traded at a $3.75/barrel discount to WTI during the period, but by the third week of April had widened slightly to $5/barrel. While the narrowing discount to WTI in the early months of 2014 clearly helped improve Bakken economics, it raises a question mark concerning the competitiveness of shipments to the seaboards and the Gulf Coast. The same issue arose in the third quarter of 2013 when discounts narrowed sharply. Based on a $4/barrel WTI-Brent discount, Bakken would need to trade at a discount to WTI of $8-9/barrel to be competitive in Gulf Coast markets. Competitiveness along the eastern seaboard might require a discount of $11-12/barrel.

Refinery capacity expansion: The sizeable discounts required to sell Bakken crude on the coasts clearly depresses producer economics. The antidote would be to sell more crude into the upper Midwest and mountain state refineries. This strategy, however, is constrained by high refinery utilisation rates. Some modest relief is at hand given actual and planned capacity expansion in North Dakota. Five refinery projects here are in the pipeline. The first relates to the construction of the Dakota Prairie refinery at Dickinson in the west of the state. This is a joint venture between MDU Resources and Calumet Specialty Products and relates to a relatively small 20,000b/d topping facility focusing on distillates and naphtha. Start-up is expected in the fourth quarter of 2014. The other four projects also relate to topping facilities but are still at the planning stage.

Refinery expansion in North Dakota is being driven by surging demand for diesel and other distillates in the region as a direct result of the petroleum industry development boom. Given the buoyant energy driven economy in the northern Great Plains, further refinery expansion projects are a very real possibility in both the upper Midwest and the mountain states.

Bakken economics: Attractive at late April prices

At late April 2014 prices of around $98/barrel, Bakken economics appears attractive as indicated below:

Exhibit 23: Bakken economics

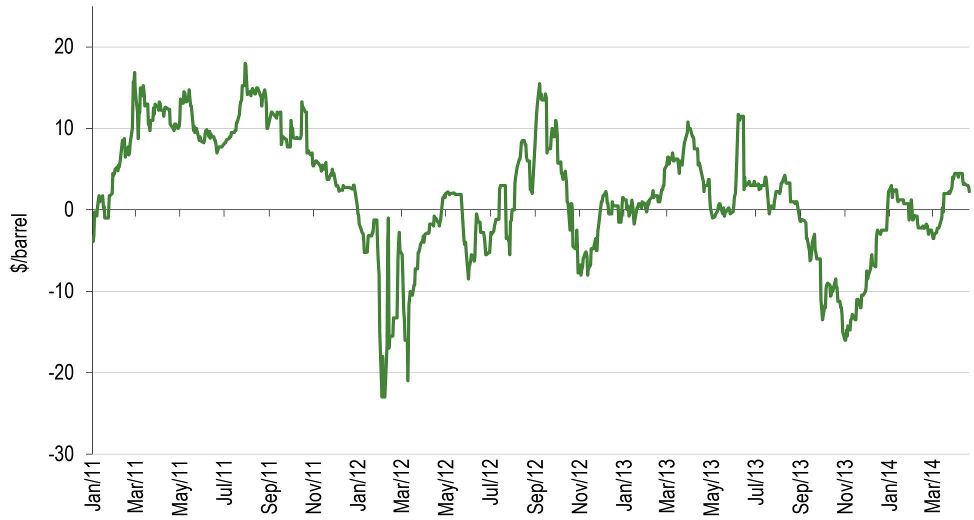
	$/barrel
Gross realisations	98
Royalties	-18
Net realisations	80
Lifting and site operating costs	-12
Severance costs	-5
G&A	-5
Transport to Clearbrook, Mn	-5
EBITDA	53
Drilling/completion costs	-15
EBIT	38
Assumptions	
Royalty rate 18.5%	
Severance rate 5%	
Drilling/completion costs $8m/well, EUR 550,000 barrels	
No allowance for natural gas	

Source: Edison and industry presentations.

Syncrude –WTI: Modest Syncrude premium in April?

Syncrude is a synthetic sweet crude sourced from the Athabasca oil sands in Alberta. The pricing hub is Edmonton Alberta. Given significant refining capacity in Alberta and Saskatchewan and also pipeline capacity to the Midwest and Ontario, Syncrude normally trades close to WTI. Refinery and pipeline outages, however, can at times result in substantial deviations, as in the fourth quarter of 2013 when a discount of $16/barrel opened up in November. Pipeline upgrades to Enbridge's existing network and construction of the northern leg of the Keystone XL, assuming it is ever given the go ahead, should improve the consistency with which WTI is tracked. We believe pipeline costs from Edmonton to the Gulf Coast are currently about $10/barrel but could potentially be somewhat less with Keystone XL reflecting a more direct route. To be competitive on the Gulf Coast currently Syncrude would probably need to trade at a discount to WTI of about $7/barrel (WTI discount to Brent of $4/barrel assumed).

Exhibit 24: Syncrude-WTI spread



Source: Bloomberg

Syncrude traded at approximate parity with WTI on average during the first quarter of 2014, thereby reversing the position in the fourth quarter of 2013 when there was a discount of $9.60/barrel. Significantly, a Syncrude premium emerged in late March and continued into April when it stood at $3.0-4.5/barrel. The strengthening trend in Syncrude vis-a-vis WTI during the first quarter appears to have reflected the potential for supply interruptions due to the harsh weather conditions. As far as we are aware, however, there were no major unplanned outages in the oil sands during the first quarter. On the contrary, the production trend appears to have been robust. The announcement by Syncrude Canada in late April concerning unplanned maintenance at one of two coker facilities has the potential to widen the Syncrude premium in the coming weeks. This may however be obviated by a decision to defer planned maintenance on the second coker.

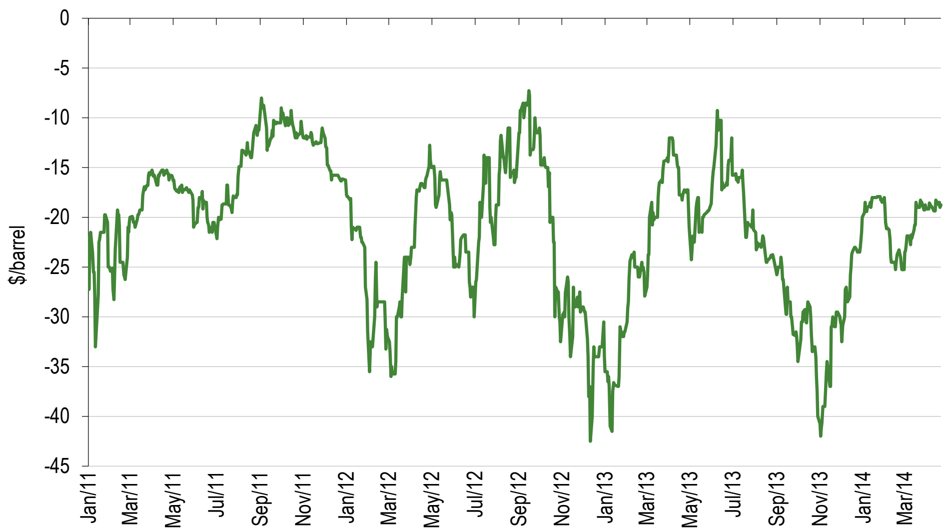
WCS-WTI: WCS discount narrows to more normal levels in 2014

WCS (Western Canada Select) is a heavy-sour Alberta blended grade using conventional and oil sands bitumen feedstock with an API of 20.5˚. The pricing hub is Hardisty, Alberta. Reflecting the specification and sourcing, WCS typically sells at a substantial discount to WTI and is usually one of the world's lowest cost crudes.

During the first quarter of 2014, WCS traded on average at a discount of $21/barrel to WTI while in early April there was a narrowing to about $19/barrel. For comparison, the discount in the fourth quarter was a hefty $31/barrel and the long term average is about $18/barrel. The pronounced narrowing of the discount in recent months partly reflects fears concerning the potential impact of harsh weather conditions on output as for Syncrude, and in part the boost to demand stemming from BP bringing fully on-stream its upgraded Whiting, Indiana, refinery. Whiting now uses 80% heavy feedstock sourced from Alberta rather than 20% previously. The impact of this changeover is about 0.3mmb/d.

With the WCS price down to about $50/barrel during November 2013 concern had been expressed in industry circles for the viability of new oil sands projects particularly based on mining. The Canadian Energy Research Institute (CERI) had put the fully accounted cost, including a 10% return on investment for such projects, at $68/barrel of bitumen. Based on the in-situ steam-based production route, fully accounted costs were significantly lower at $48/barrel, but economics would be pretty marginal assuming a price of $50. With the firming in the WCS price in 2014 to about $83/barrel, economics would appear to have been transformed on either the mining or in-situ production routes. It needs to be remembered however that long-distance shipments of WCS by pipeline are particularly costly due to high viscosity and the need to add dilutants. CERI estimates the cost of blending and transportation to the Gulf Coast at approaching $30/barrel. There is therefore a clear incentive to refine WCS in Alberta or the upper Midwest.

Exhibit 25: WCS-WTI spread

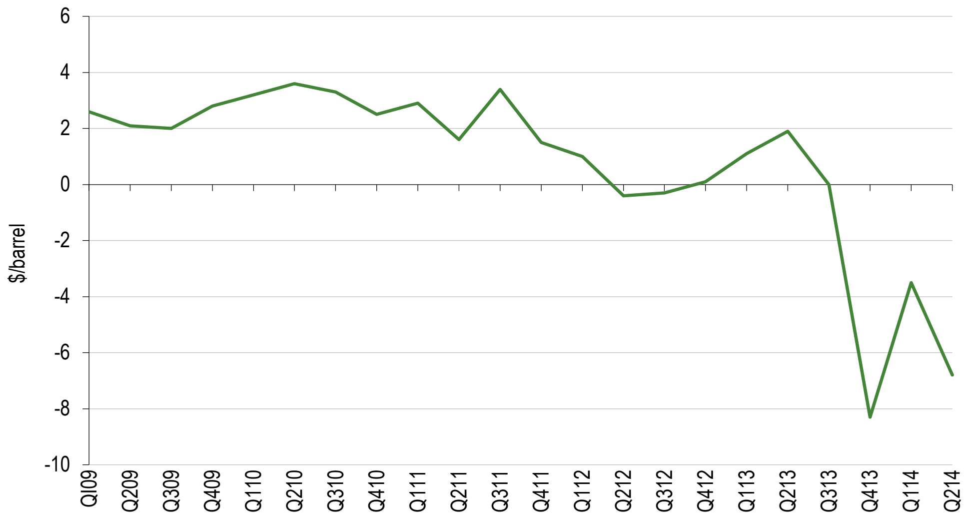


Source: Bloomberg

LLS-Brent: LLS discount widens in April as Gulf Coast inventories rise

The relationship between LLS, the Gulf-based light crude benchmark and Brent changed fundamentally during 2013. Rather than trading at the premium of a dollar or two that had historically prevailed, LLS swung sharply to a discount in the second half. During the fourth quarter the average discount indeed came in at $7.4/barrel, an unprecedented outcome. In the first quarter of 2014 the LLS discount to Brent narrowed but was still highly significant at $3.5/barrel on average. This compared with a premium of $1.1/barrel a year earlier. By late April the LLS discount to Brent had widened to $6/barrel, which was symptomatic of both the Gulf Coast inventory build-up and the evolving Ukraine crisis supporting Brent. Longer term we would expect LLS to trade at a structural discount to Brent of at least $2-3/barrel and possibly over $5/barrel. Much will depend on the persistence of bloated inventories along the Gulf Coast. Logistical upgrades stemming from new pipeline and rail links from the Mid-Continent and the prolific Permian and Eagle Ford producing zones are possibly pointing to a LLS discount towards the high end of the above range.

Exhibit 26: LLS-Brent spread



Source: Bloomberg

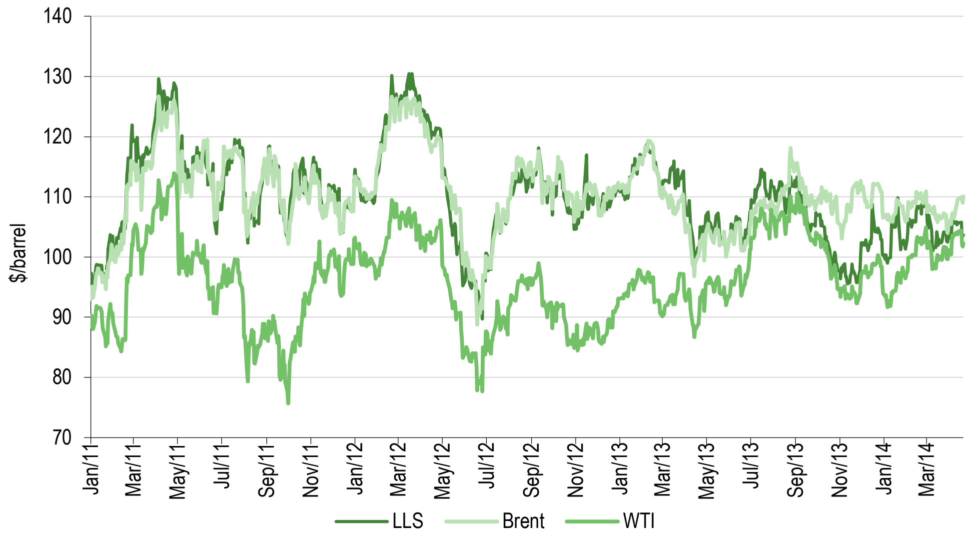
Brent-Dubai: Normal Dubai discount

Dubai Fateh is a Gulf-sourced light but relatively sour crude popular with Far Eastern refineries. During the first quarter of 2014, Dubai traded at an average discount to Brent of $3.3/barrel, slightly above the longer-term average and also in excess of the $2.3/barrel of the fourth quarter of 2013. The growing availability of sour grades from Iran and Iraq has possibly facilitated a slight widening of the Dubai discount in recent months. An accord between the west and Iran concerning Iran's nuclear programme could result in a further widening of the discount reflecting potentially greater availability of sour crude. Presently, the Dubai-Brent spread tends to be very sensitive to supply interruptions related to terrorist attacks on the Kirkuk (Iraq)-Ceyhan (Turkey) pipeline.

Tapis-Dubai: Tapis premium towards the high end of the range

Tapis is a low-sulphur Malaysia-sourced light crude popular with refineries in the Far East. The Tapis-Dubai spread is one of the key sweet-sour crude oil price relationships. Reflecting its premium specification, Tapis typically trades at a significant premium of $7-10/barrel. During the first quarter of 2014 the premium was in line with the top end of the historical range and largely unchanged from the fourth quarter of 2013. We continue to believe the Tapis premium to sour grades is vulnerable medium term to a growing surplus of light oil in the Atlantic basin.

Exhibit 27: Recent trends in WTI, LLS and Brent

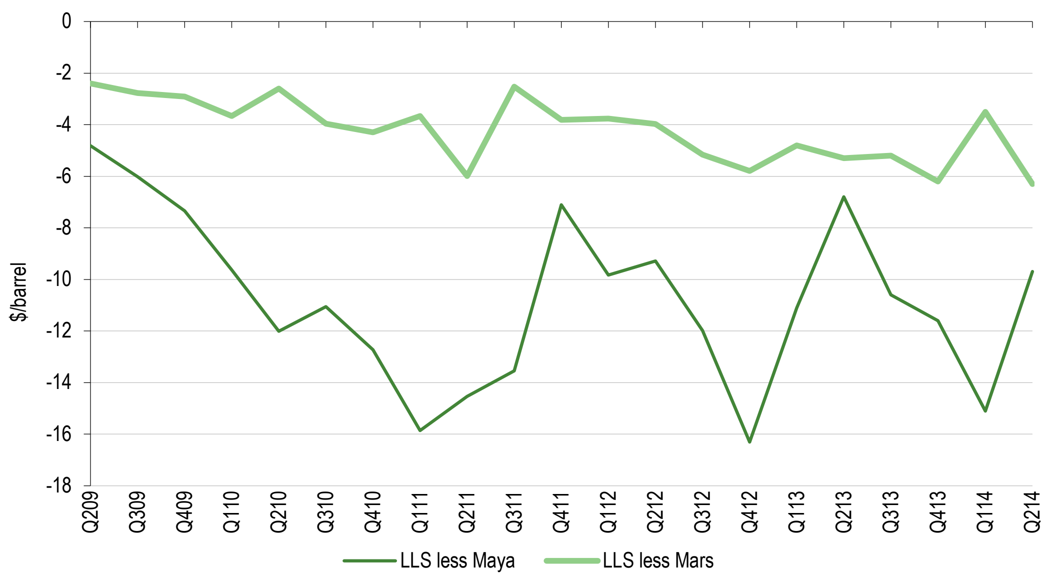


Source: Bloomberg

US Gulf heavy crude spreads: Mars and WTS sour discounts widen in April

LLS-Mars: Mars is a medium-sour grade sourced from the Gulf of Mexico that normally trades at a discount of $2-6/barrel. The Mars discount narrowed somewhat between the fourth quarter of 2013 and the first quarter of 2014 from $5.2 to $3.5/barrel but remained well within the historical range. Weighing on the discount in recent months was the abundance of light crude along the Gulf Coast and the more constrained supply of sour grades. The expected continuing build-up of light crude supply along the Gulf Coast could portend a longer term narrowing of the Mars discount. It should be remembered here that many Gulf Coast refineries are currently configured for heavy-sour feedstock. However, during April the Mars discount widened somewhat and towards month end was around $6.3/barrel. We believe this stemmed from the release of sour crude from the strategic reserve in March.

Exhibit 28: US medium and heavy discounts

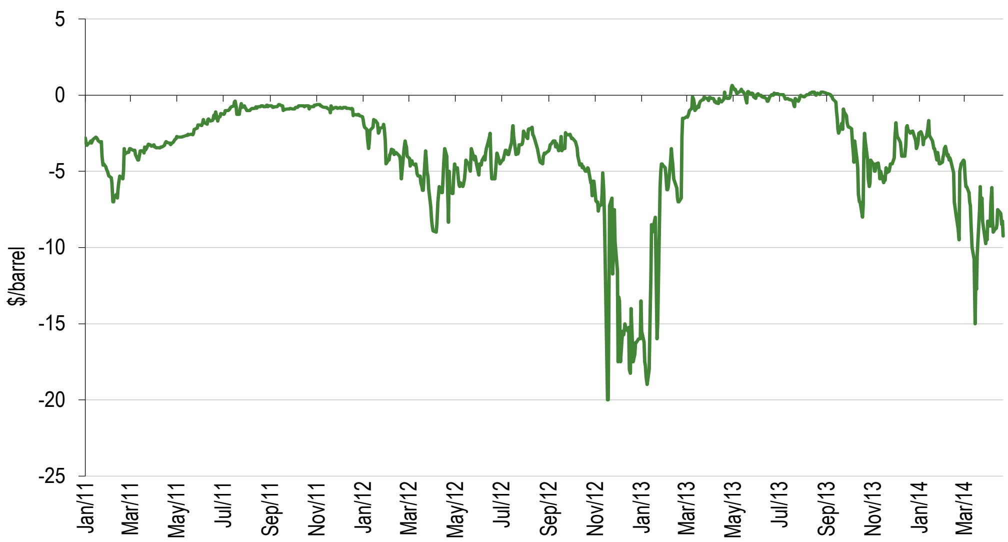


Source: Bloomberg and Edison Investment Research

LLS-Maya: Maya is a Mexico-sourced heavy-sour grade with a specification similar to WCS. It normally trades at a discount to LLS in the range of $5-12/barrel. The Maya discount widened significantly between the fourth quarter of 2013 and the first quarter of 2014 from $11.6 to $15.1/barrel. This may also have been attributable to the release of sour crude from the strategic petroleum reserve during March. By early April, however, the Maya discount had eased to $12.6/barrel and towards end month was $9.7/barrel.

WTS-WTI: West Texas Sour (WTS) is a US inland medium-sour grade with a specification similar to Mars and a delivery point of Midland, West Texas. Historically, WTS has generally traded at a discount to WTI of $1-3/barrel. Recently, the discount has been significantly wider and in the first quarter of 2014 averaged $5.5/barrel while in late April was around $9/barrel. The widening of the WTS discount, we believe, reflected in part a pipeline outage and in part the release of sour crude from the strategic reserve.

Exhibit 29: WTS-WTI spread

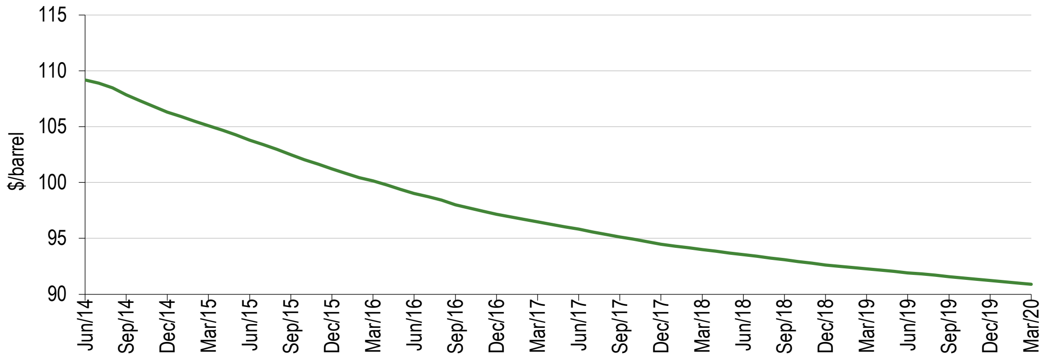


Source: Bloomberg

Forward curves: Brent curve flattens WTI moves into mild backwardation

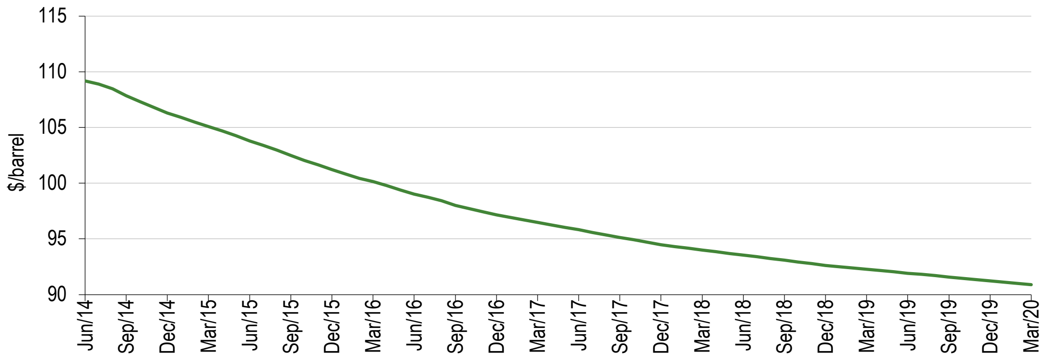
The forward curves for Brent and WTI have shown two significant structural changes since our last report in late January 2014. In the case of Brent there has been a flattening of the longstanding backwardation (near-term prices higher than for the forward dates) feature. Indeed, in recent weeks the curve at times has flirted with contango (near term prices lower than for the forward dates) at the front end of the curve. As of late April the curve starts at $109.2/barrel for June deliveries before dipping to $99.8/barrel over the following two years. It then begins to flatten, terminating in March 2020 at $90.9/barrel. Less pronounced Brent backwardation in recent months reflects the increasing availability of supplies in the eastern Atlantic Basin. In the absence of the Ukraine crisis we suspect the Brent forward curve may well have shown a stronger contango tendency.

Exhibit 30: Brent forward curve



Source: Bloomberg

Exhibit 31: WTI forward curve



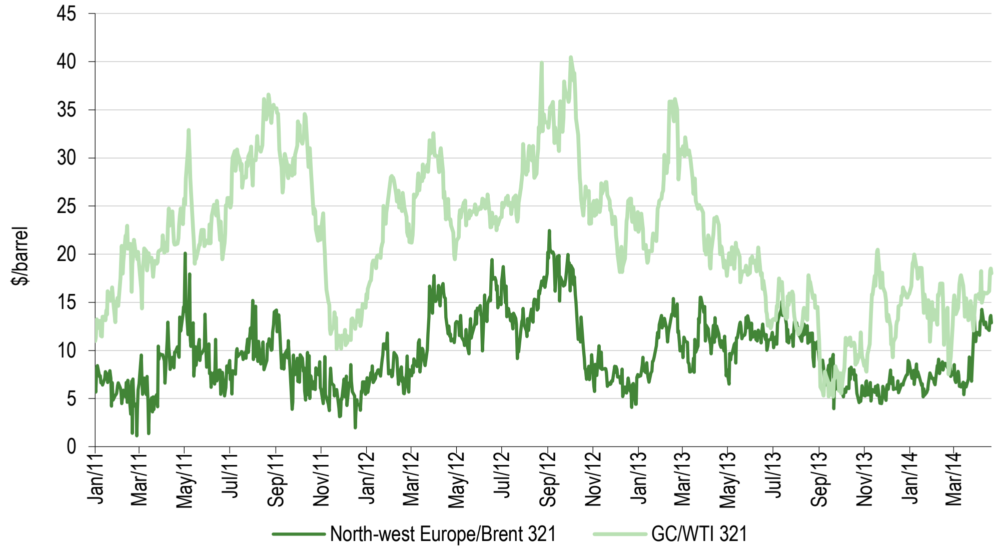
Source: Bloomberg

In the case of WTI, the key change in recent months has been a swing from mild contango to backwardation at the front end of the curve. After commencing at $101.9/barrel for June deliveries, the curve dips sharply over the following two years to $87.5/barrel. Subsequently the curve flattens and terminates in late 2022 at $80.7/barrel. The implied WTI discounts to Brent are $7.2/barrel in June 2014, $12.3/barrel in June 2016 and $9.9/barrel in March 2020. WTI backwardation at this time with record inventory along the Gulf Coast and growing production in the Mid-Continent appears decidedly counter intuitive given that the phenomenon is usually associated with tight supplies. One explanation is the sharp fall in inventories at Cushing, although there is no indication that this has been involuntary. A further possibility is that backwardation is being driven by hedging as operators under pressure from lenders attempt to reduce risk by locking in futures prices through derivative instruments. This is possibly increasing supply and reducing prices in the out years.

Refinery crack spreads: Gulf Coast spreads widen in recent months

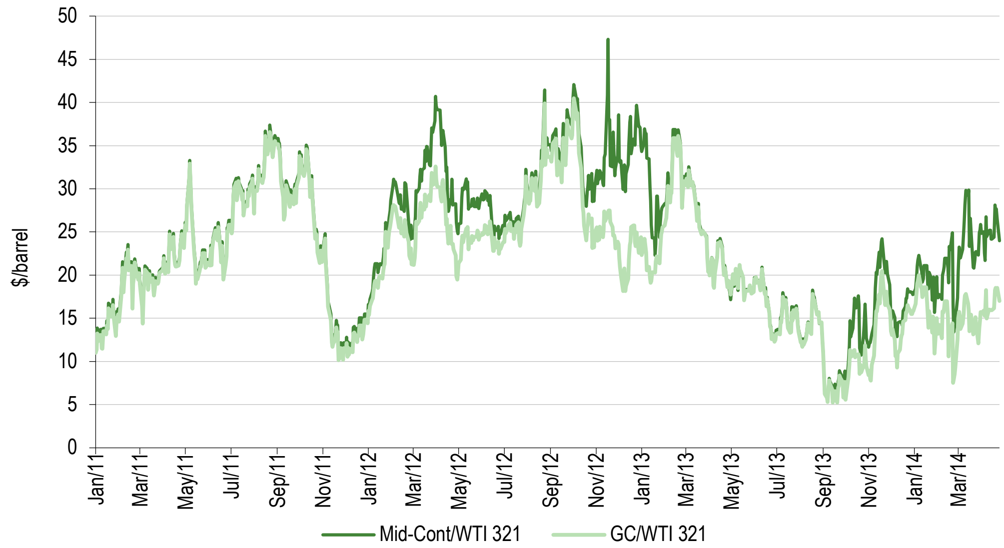
US Gulf Coast refinery crack spreads trended modestly higher between the fourth quarter of 2013 and the first quarter of 2014. Taking, for example, the Gulf Coast/WTI 321 spread (the margin before refining costs on converting three barrels of WTI into two barrels of gasoline and one of diesel) there was an upward move on average between the two quarters from $12.3/barrel to $14.5/barrel. In early April the margin was slightly higher than in the first quarter at $15/barrel while late in the month it had firmed to about $18/barrel. While the GC/WTI 321 spread currently is well down on peak levels in recent years of over $30/barrel it is above the five-year average of $16.4/barrel. Mid-Continent spreads are significantly higher currently than those for Gulf Coast refineries reflecting lower feedstock costs and higher refined product prices. The Mid-Continent/WTI 321 spread in late April was $30/barrel, an excellent level by international standards. The five-year average for the Mid-Continent/WTI 321 spread is $20.5/barrel.

Exhibit 32: Recent trends in Gulf Coast and NW Europe crack spreads



Source: Bloomberg

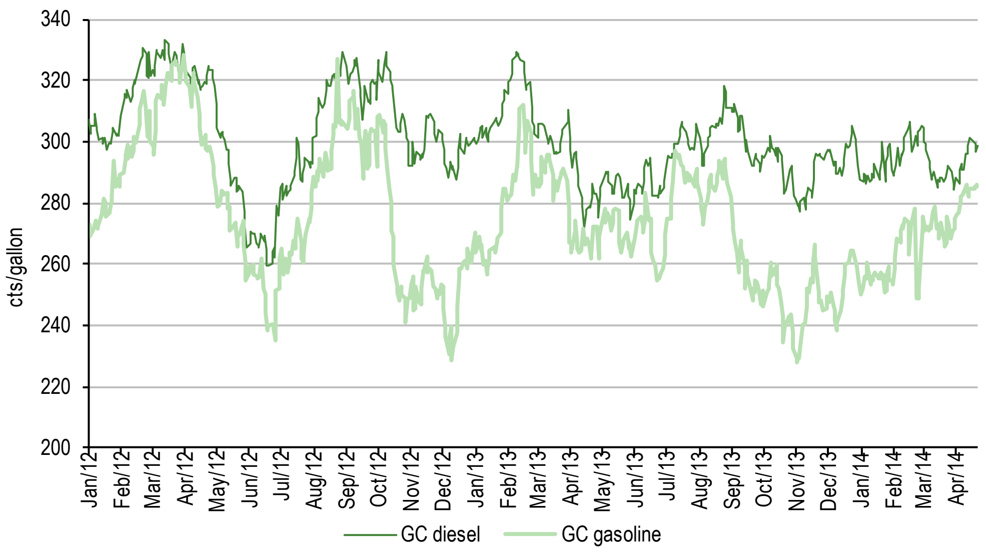
Exhibit 33: Recent trends in Gulf Coast and Mid-Continent crack spreads



Source: Bloomberg

The firming trend in USGC crack spreads between the fourth quarter of 2013 and the first quarter 2014 reflects a pronounced rise in refined product prices. From the lows in November 2013 to early April, regular gasoline and diesel Gulf Coast wholesale prices have risen by about 23% and 14%. Overall, product prices have kept ahead modestly of the gain in feedstock stocks. For 2014 as a whole, we think it unlikely that the USGC/WTI 321 crack spread will be significantly different than 2013's $17.6/barrel. The assumption here is that wholesale product prices on average in 2014 will be much the same as in 2013 while feedstock costs will be slightly lower.

Exhibit 34: Gulf Coast wholesale gasoline and diesel price trends



Source: Bloomberg

Crude oil price outlook: Forecasts upgraded reflecting year-to-date trends and Ukraine

At the beginning of the year we were predicting a downward trend in both international light crude prices and WTI in 2014 based on bearish fundamentals. Specifically, we suggested that the anticipated very buoyant growth in non-OPEC production would comfortably outpace global demand and that OPEC output would be more or less in line with the implied call. Superimposed on this underlying scenario was the potential for significant output gains for at least two OPEC members, Iraq and Libya. There was also the possibility of Iran boosting exports in the second half of 2014, subsequent to an accord with the world's major powers over its nuclear programme. The scenario has been along the right lines except that US demand has been a little higher than expected and uncertainty still surrounds the timing concerning the resumption of large-scale exports from Libya. Most importantly, however, the Ukraine crisis with its potential, albeit remote, for disrupted energy supplies has emerged as a new source of worry of late for oil markets.

In the light of the above plus more robust price trends than expected in the year-to-date, we are raising our price forecasts for Brent and WTI for 2014. For Brent we are now looking for an average during the year of $105.4/barrel against $103/barrel previously. Our quarterly scenario is as follows: Q1 $107.9 (actual), Q2 $107.0, Q3 $104.0, Q4 $102.5. Key assumptions here are that the Ukrainian crisis dissipates during the third and fourth quarters of 2014, there are no new major and sustained field outages in the coming months and that Libyan exports are restored to the semblance of normality (defined as at least 500,000b/d) during the second quarter. We continue to believe rising non-OPEC production, possibly supported by rising OPEC supplies particularly from Iraq and Libya, will exert significant downward pressure on Brent in 2015. On average for the year we look for $99.5/barrel. This constitutes an upgrade compared with the $98.0/barrel given previously reflecting greater assumed carryover strength from 2014. The key risks to the upside for Brent in 2014/15 are supply related, mainly revolving around geopolitical issues and OPEC's policy stance on production. A key issue will be how OPEC plans to allow for higher production from Iraq, Libya and possibly Iran.

In the case of WTI we also continue to look for rapidly growing US light crude production ultimately exerting downward price pressure in 2014 and 2015. The trend, however, has been firmer in the year-to-date than originally expected so we are raising our forecast for the full year from $94.0 to

$96.3/barrel. The quarterly split is as follows: Q1 $98.7, Q2 $98.0, Q3 $95.0, Q4 $93.5. Positive carryover influences have led to us raising our forecast from $89.5/barrel to $91.0/barrel for 2015. We see the key issues for WTI over the next 18 months as being the following:

- The robustness of local production.
- The strength of the US economy.
- Regulatory developments particularly regarding, water usage and transportation all of which could have a bearing on supplies.

Exhibit 35: Brent and WTI price scenarios

$/bbl	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015e
WTI	56.6	66.1	72.2	99.8	62.0	79.5	94.9	94.2	98.0	96.3	91.0
Brent	54.5	65.4	72.7	97.7	62.0	79.7	110.0	112.0	108.8	105.4	99.5

Source: Bloomberg and Edison Investment Research. Note: Prices are averages.

US natural gas market

Production and net imports

Recent trends: Production buoyed by Marcellus and by-product gas in shale oil plays

Production: The trend in US natural gas production was subdued in 2013, reflecting the lagged response to declining drilling activity. Marketed production, however, still reached a record 25. tcf, up 1.2% on a year earlier. As has been the case for several years, production continued to be supported by rapid development activity in the prolific Marcellus shale zone of Pennsylvania and West Virginia plus by-product gas in major shale oil plays such as the Bakken and Eagle Ford. Significantly, production in the Marcellus rose in 2013 by almost 50% to 3.8tcf. At end year production from this source was running at around 5.1tcf, equivalent to roughly 18% of the US total. The Marcellus formation is now the largest source of gas in the US. Production also rose strongly in 2013 from a low base in the deeper Utica shale formation of Ohio and Pennsylvania. The increase in the former state alone was 145% to 203bcf. Surging production in the Marcellus and Utica helped offset declining output in the traditionally large producing states and regions such Louisiana, Texas, Wyoming and the Gulf of Mexico. In the case of Texas, traditionally the largest producing state, there was a 1.3% drop in output in 2013 propelled by declines in the large mature plays, notably the Barnett. Eagle Ford production, however, rose by 40% in 2013 to 1.32tcf, roughly 18% of the state total.

In the first quarter of 2014, US natural gas production was disrupted from time to time by severe weather conditions. Nevertheless, according to the EIA, data production was still up by 4.2% year-on-year in January 2014 driven by a 20% increase in the ‘other’ category, which includes the new large scale producing states such as Pennsylvania, Ohio, West Virginia and North Dakota. Based on data provided by the consultancy Benteck Energy LLC, US natural gas production continued to show year-on-year gains in early April of slightly over 4%.

Net imports: US net imports of gas continued to trend down significantly in 2013 reflecting both declining gross pipeline imports from Canada and rapidly growing exports to Mexico. For the year, imports from Canada were down 6% while exports to Mexico were up 6.2%. LNG and pipeline imports from Mexico were both running at a trickle in 2013. Overall in 2013, net imports were 1.31tcf, down 14% on a year earlier and less than half the level prevailing as recently as 2009.

In early 2014 the downward trend in net imports was reversed due to sharply higher consumption in the US related to harsh weather conditions, which sucked in pipeline imports from Canada and reduced pipeline exports in the opposite direction, and also to Mexico. We would, however, expect these trends to be reversed in the coming months. Significantly, in the case of Mexico, a substantial

2bcf/d of pipeline export capacity is being added linking the Agua Dulce hub in Texas with northern Mexico. This should be on stream by late 2014. Note, Mexico's demand for gas is growing by about 5% pa while domestic capacity is constrained. Furthermore, supplies of gas from Texas are available at prices close to US levels and therefore considerably below international levels for LNG of $15-16/mmBtu.

Outlook:Modest production growth still looks like the most likely scenario in 2014/15

Subdued drilling activity over the past year or two combined with the downward trend in the Gulf of Mexico, is likely to constrain US marketed natural gas production near to mid-term. Helping to support production should, however, be a combination of still buoyant development activity in the prolific Marcellus formation, growing by-product gas production in shale oil plays and rising new well productivity reflecting advances in completion techniques. The EIA's forecasts call for US production gains of 3.0% in 2014 and 1.5% in 2015 to 26.4tcf and 26.8tcf respectively. These forecasts are slightly up on three months ago.

Consumption

Recent trends: Consumption boosted by harsh weather in first quarter

The trend in US natural gas consumption was sluggish in 2013 with a gain of 2% to 26.0tcf. Constraining growth was a sharp 10.5% drop in power generation use, the largest market segment for natural gas. The drop was a function of a decline in the power station natural gas burn rate from 30.3% in 2012 to 27.4% in 2013. This in turn stemmed from a marked loss in competitiveness for natural gas vis-à-vis coal in power generation with the former rising by 26% and the latter falling by a 1% or so on a per million Btu basis.

The early months of 2014 witnessed a surge in US natural gas consumption very much driven by harsh winter weather not only across the Midwest and eastern seaboard but also the southern states. The contrast with 2012 and 2011, when mild winter weather conditions prevailed, could not have been more marked. Based on EIA data, demand in January 2014 was 12.3% higher than a year previously, while for the first quarter as a whole there was an estimated year-on-year gain of 7.9%. Not surprisingly, demand was driven by residential (about 50% of households use gas for space heating) and commercial markets where, according to the EIA, there were gains of 15.7% and 13.1% respectively. Industrial markets, by comparison, showed a smaller gain of 5.4% while usage in the power generation market was down 1.9% year-on-year reflecting further slippage in the natural gas burn rate. For 2014 as whole, the EIA is looking for the power station natural gas burn rate to drop to 26.5% related to the declining competitiveness of gas vis-à-vis coal.

Outlook: EIA's forecast of 1% growth in 2014 looks conservative

The EIA is forecasting growth in US natural gas consumption of 1.0% in 2014. This appears conservative in the light of the buoyancy of demand in the first quarter and the strengthening economy. The explanation is in part the anticipated decline in power station usage and in part the assumption of more normal weather patterns over the balance of 2014. Even allowing for these factors, the forecast could still be on the low side in our view. For 2015 the EIA is forecasting a slight 0.5% drop in US natural gas consumption. This stems from a decline in demand from the residential/commercial sector again based on an assumed return to more normal weather patterns. Interestingly, the EIA is anticipating power station demand to increase by 3.6% in 2015 reflecting the decommissioning of a number of coal-fired power stations. Tightening regulation could result in further increases in the US natural gas power station burn rate in the years to come.

LNG export projects: First project to come on-stream late 2015/16

The surge in US natural gas reserves over the past 10 years or so combined with a depressed domestic price regime (on an international comparison) has led to plans to establish a major LNG export business. So far, 24 companies have applied for export approval from the Department of Energy with seven gaining it. However, only one project has been approved both in terms of export and federal environment/safety compliance. This relates to Houston-based Cheniere Energy's Sabine Pass facility located next to the Sabine River in Louisiana. Construction here is underway with completion expected in late 2015. Initially the capacity of Sabine Pass will be about 3bcf/d in terms of processing and 4mmtpa in terms of liquefaction. The seven projects granted export approval will have processing capacity of about 10bcf/d. The capacities involved are significant in relation to current US natural gas production. Sabine Pass alone would account for 4% of the total while the seven projects with export approval would be equivalent to 14%.

LNG exports from the US have understandingly proven controversial. Those in favour focus on:

- The considerably higher prices that can be captured by exporting natural gas in LNG form rather than selling it domestically. The differential currently stands at about $9.5/mmBtu when comparing the Henry Hub benchmark at $4.5/mm Btu with Far East LNG contract levels of $19/mmBtu and after backing out liquefaction and shipping costs of perhaps $5/mmBtu.
- The claimed geopolitical advantages of lessening the quasi-monopoly power of large natural gas/LNG producers notably Qatar and Russia. Clearly, however, the US is in no position to influence the international marketplace in the short term, given that the Sabine Pass facility will probably not be on stream until 2016. Even then, the LNG capacity available will be relatively small from an international perspective.

By comparison, those opposed to LNG exports stress the potential adverse implications for domestic natural gas prices and therefore economic activity. There are also potential negative environmental aspects to producing and transporting LNG. Furthermore, to serve both domestic and LNG export markets would require greatly stepped-up development of US natural gas reserves which arouses concern in environmentalist circles.

Inventories: Pronounced rundown, below seasonal average

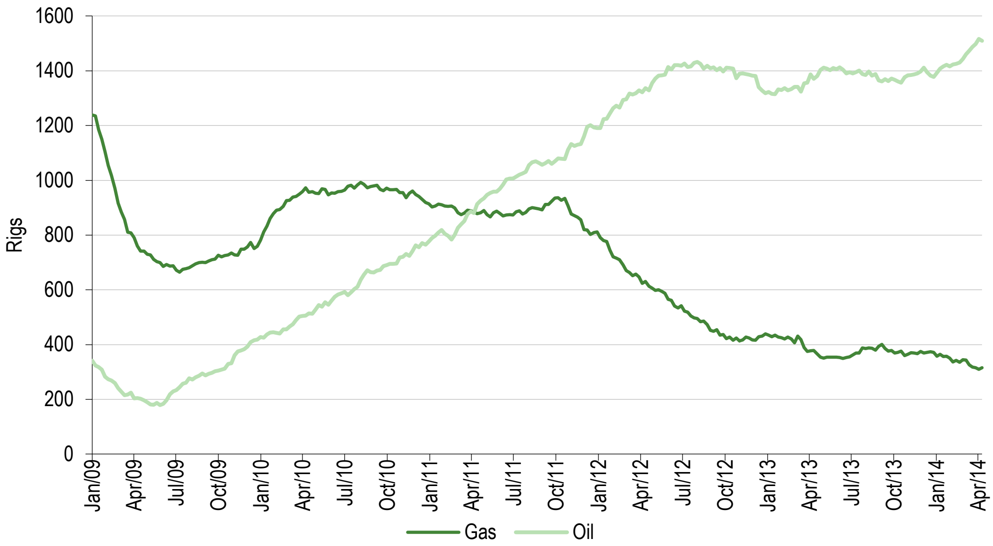
For a number of years US natural gas inventories have tended to be consistently seasonally high. This tendency, however, changed dramatically in recent months, reflecting the surge in consumption associated with the sustained period of exceptionally cold weather over the past winter. According to the EIA, withdrawals of gas from storage in the US between early November 2013 and end March 2014 were the largest since 1994-95 at almost 3tcf. The average withdrawal is about 2bcf. Based on data for 4 April inventories stood at 826bcf, down 849bcf or 51% on a year earlier. Compared with the five-year average, there was a shortfall of 997bcf or 55%. In the absence of a very mild summer with low air conditioner usage inventories are likely to enter the next withdrawal period at the end of October below the seasonal average. The EIA is forecasting inventories of 3.4bcf, 0.4bcf less than usual.

Drilling activity: Oil dedicated rig count rising, gas falling

US drilling activity has firmed in the opening months of 2014. Based on Baker Hughes data, the rotary rig count overall on 11 April was 1,831, up 4.2% end 2013 and 3.4% on a year earlier. Compared with the 4 November 2011 high of 2,026, there was a decline of 9.6%. The recent firming in the rig count has been very much an oil phenomenon. Since end 2013, the oil-dedicated rig count has climbed by 9.8% to a record 1,517. Interestingly, the increase in the oil based rig count since the end of 2013 has largely been driven in terms of basins by the Permian Granite Wash and the DJ-Niobrara plus a group of locations which are effectively included under miscellaneous. These include Oklahoma and California. Compared with end 2013 the rig count overall has increased by 48 in Texas (Permian and Granite Wash), 20 in Oklahoma, 13 in New Mexico (Permian) and seven in California. Elsewhere, the rig count has been roughly flat in recent months in the Williston Basin and in the Eagle Ford play.

After showing signs of levelling off in 2013, gas-dedicated drilling activity has resumed a downward course so far in 2014. The gas rig count on 11 April was a mere 310, down 17.1% on end 2013 and 18% on a year earlier. For perspective, at the peak in 2008 the gas rig count was around 1,600 and as recently as late 2011 was running at around 900. The declining trend continues to reflect still fairly marginal fully accounted natural gas economics at prevailing benchmark prices and greatly superior economics in liquids plays. We continue to believe that US prices will probably have to exceed $5/mmBtu on a sustained basis before dry gas drilling activity reverses the downward trend that has been apparent since late 2011.

Exhibit 36: Baker Hughes US rig count



Source: Baker Hughes, Bloomberg

Recent price developments and outlook

Dry gas: Early first quarter price surge

US natural gas prices started to trend strongly higher late in the fourth quarter of 2013 with the onset of very cold temperatures. Sustained seasonally cold conditions and the consequent pronounced tightening in the market place resulted in the upward trend continuing early in the first quarter of 2014. Taking the Henry Hub, Louisiana benchmark, the spot price rose from $4.34/mmBtu at end December 2013 to a spot high of $7.73/mmBtu on 11 February 2014. The slightly higher $7.92/mmBtu recorded on 3 March was the highest level for the Henry Hub since the third quarter of 2008. As weather conditions turned more benign towards the end of March, the Henry Hub quote slipped rapidly and by end month was at $4.47/mmBtu, only 3% above the end December level. The Henry Hub quote however averaged $5.16/mmBtu during the first quarter of 2014, which was a post first quarter 2010 high and 48% above a year previously. In early April the Henry Hub price firmed slightly and on 15 April closed at $4.67/mmBtu supported by a wave of cold air moving across the southern states and Midwest.

Exhibit 37: Henry Hub price trend

Source: Bloomberg

Over the next six months or so the critical factors for US gas prices will be weather conditions in the Midwest and eastern seaboard during the peak months of air conditioner use and the sustainability of the recent buoyant trend in natural gas production. A combination of hot conditions in the third quarter and a more sluggish trend in production could quite possibly result in the Henry Hub averaging over $5/mmBtu in the coming months. By contrast, a continuation of the buoyant production trend of late and a relatively cool summer might conspire in a price closer to $4/mmBtu. We are shooting for somewhere between the two scenarios. Our forecasts call for a seasonal dip in the second quarter taking the Henry Hub down to an average of $4.25/mmBtu. The seasonal upturn in air conditioner usage and electricity consumption is then forecast to lift the Henry Hub quote to $4.30/mmBtu in the third quarter. In the fourth quarter we look for a slight firming to $4.35/mmBtu with the onset of winter and a tightening in the marketplace. Based on this scenario, the Henry Hub would average for 2014 $4.53/mmBtu, up 12% on our earlier forecast of $4.04/mmBtu. The underlying reasons for the upgrade are the higher than forecast outcome for the first quarter and a considerably tighter inventory backdrop.

Assuming seasonally normal winter and summer weather conditions US natural gas prices could trend down modestly on average between 2014 and 2015. The key angle here is that the supply-demand balance will slacken, other things being equal, between the two years given the importance of weather conditions for gas use. Based on a normalisation of weather conditions we look for the Henry Hub quote to average $4.33/mmBtu in 2015 with a quarterly profile as follows: Q1 $4.60, Q2 $4.00, Q3 $4.30, Q4 $4.40. The new forecast is modestly above the previous $4.20/mmBtu reflecting greater carryover strength in the trend from 2014 than assumed previously. Much will depend, of course, on whether the inventory position can be normalised in the coming months. A recurrence of 2014's severe winter weather could in our view send the Henry Hub average for 2015 above $5/mmBtu. Such an outcome has not occurred since 2008.

Exhibit 38: Henry Hub quarterly price scenario

$/mmBtu	Q1	Q2	Q3	Q4	Average
2008	8.66	11.37	9.06	6.45	8.89
2009	4.54	3.70	3.17	4.37	3.94
2010	5.15	4.15	4.32	3.86	4.37
2011	4.18	4.37	4.12	3.33	4.00
2012	2.43	2.29	2.88	3.40	2.75
2013	3.49	4.02	3.55	3.84	3.73
2014e	5.16	4.25	4.30	4.40	4.53
2015e	4.60	4.00	4.30	4.40	4.33

Source: Bloomberg and Edison Investment Research. Note: Q114 is an actual.

NGLs: Prices also surged in early 2014 but strong output growth likely to constrain trend longer term

Natural gas liquids (NGLs) such as ethane (the highest volume NGL), propane, butane and natural gasoline are important petrochemical feedstocks, gasoline-blending agents and fuels. They are valuable by-products of natural gas production.US NGL production has grown rapidly in recent years in tandem with the development of liquids-rich natural gas formations such as the Marcellus and Eagle Ford. In 2013, production based on EIA data increased by 6.1% to 2.56mmb/d which comfortably outpaced the 1.2% gain in dry gas. In the year-to-date 11 April 2014 US NGL production has continued to grow rapidly. Production on this basis averaged 2.67mmb/d, up 9.0% on a year earlier while in the most recent four-week period there was a 10.9% year-on-year gain. The EIA is forecasting production to increase by 5.5% in 2014 but this appears unduly conservative based on the year-to-date experience.

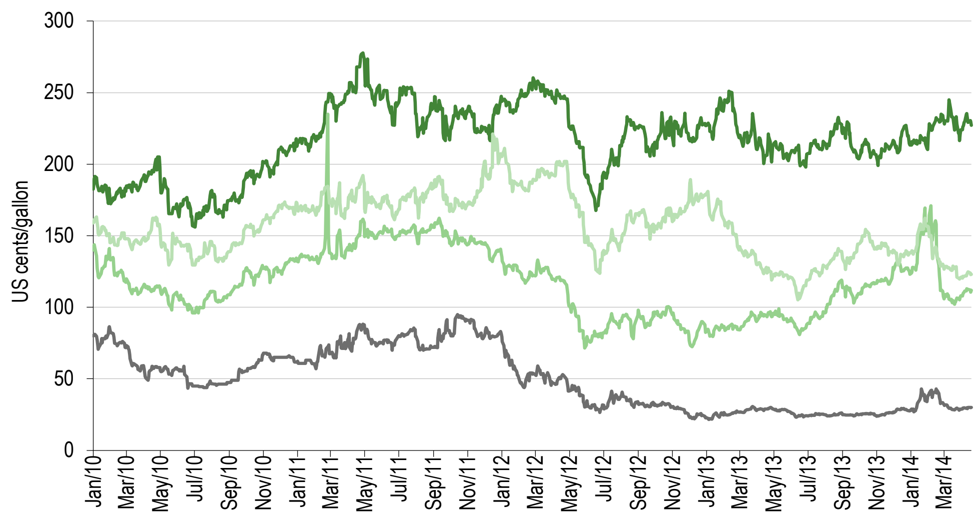
NGL prices generally firmed in the second half of 2013 from historically depressed levels driven by strengthening demand. This was related to three factors:

- Strong export demand, particularly for propane.
- The resurgence in US petrochemicals activity.
- Heavy usage of propane in the agricultural sector for grain drying needs. This in turn stemmed from a record harvest and damp weather conditions in the grain belt in the fall of 2013.

Early in the first quarter of 2014, NGL prices surged. With the exception of ethane, prices reached elevated levels based on the experience of the past five years. Compared with end December 2013 levels, prices (Mt Belvieu, Texas) at the first quarter highs were up as follows: propane +35.4%, butane +18.9%, natural gasoline +11.4% and ethane +55.0%. The first quarter price surge reflected harsh weather conditions, which not only boosted demand particularly for propane (propane is the fuel of choice for many rural locations in the Midwest) but also constrained supply due to equipment malfunctions and logistical issues. With the exception of natural gasoline, the other NGLs peaked in January/February. As weather conditions turned more benign in March, the earlier price gains were rapidly unwound. By mid-April the prices for propane and butane were below end 2013 levels by about 10%. Ethane and natural gasoline, however, were up by 7% on the same basis. NGL prices in mid-April 2014 showed the following year-on-year movements: propane +20%, butane -1.2%, natural gasoline +12.9%, ethane +4.6%.

Reflecting carryover strength and the surge in the first quarter of 2014, NGL prices on average in 2014 could show significant gains compared with 2013. Any upward trend in the months ahead, however, looks like being heavily constrained by rapidly growing supplies. This has been the key factor depressing NGL prices in recent years.

Exhibit 39: Recent trends in US NGL prices



Source: Bloomberg. Note, prices are Mt Belvieu, Texas

Natural gas economics: Dry gas economics improve but fully accounted returns probably still marginal, wet gas status vastly superior

The firming trend in natural gas prices over the past six months or so has clearly enhanced the economics of US dry gas producers. At a Henry Hub price of around $4.60/mmBtu producers should now generally be able to generate a very comfortable cash contribution. This will probably be adequate to cover finding and development costs in some cases. Returns on capital, however, are probably still fairly marginal even for the low-cost producers. Based on company reports, cash costs could be in the region of $3.26/mcf split around $1.00 for lifting, $0.23 for severance tax, $0.45 for G&A, $0.75 for pipeline tie-in and gathering and $0.83 for royalties. This would imply a cash contribution of $1.34/mcf at the above price. Finding and development costs we believe typically range from about $0.65/mcf to $3.00/mcf. It should be noted that the statement on economics is only indicative. In practice economics particularly on a fully accounted basis will vary widely depending on the resource play and the utilization rate.

The economics of wet gas producers is, of course, vastly superior to their dry gas counterparts. Particularly in the liquids-rich zones of the Marcellus and Eagle Ford, NGLs and condensates probably boosted price realisations by over $4/mcfe in the first quarter of 2014. This would have suggested realisations overall in excess of $9/mcf and quite possibly closer to $10/mcf for some producers. Admittedly, a wet gas producer has higher capital and some operational costs associated with an NGL processing plant but we think this would be much more than compensated by realisations more than twice those of a dry gas producer.

Exhibit 40: Recent trends in US NGL prices

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014e	2015e
$/mmBtu	8.79	6.72	6.96	8.89	3.94	4.37	4.00	2.75	3.73	4.53	4.33

Source: Bloomberg and Edison Investment Research. Note: Prices are Mt Belvieu, Texas

Russian gas supplies to Europe

Logistical and pricing background: Russia accounts for 30% of European demand, Gazprom supplies at a considerable discount to international LNG prices

Historically, Russia has been a major gas supplier to Europe reflecting geographical proximity and a paucity of gas reserves in the latter. According to the EIA, Europe including Turkey, consumed 18.7tcf of gas in 2013 of which around 30% or 5.7tcf was supplied by Russia. There are various pipeline routes into Europe but the two major ones, Bratstvo and Soyuz, pass through Ukraine. A third pipeline, the Trans Balkan, supplies gas to Turkey and the Balkans. The EIA estimates that in 2013 the Ukraine was the transit route for 53% or 3.0tcf of Russian gas exports to Europe. This in turn was equivalent to 16% of European consumption. The remainder of Russia's exports are shipped either via the Yamal pipeline through Belarus and Poland or the Nord Stream pipeline under the Baltic to Germany. Gazprom, the Russian state controlled gas producer, sold gas in Western Europe in 2013 at an average $10.54/mmBtu. The price is considerably below international LNG prices which range between about $12.5/mmBtu and $19/mmBtu. To these prices another $1/mmBtu or so would need to be added for re-gasification.

Presently, Europe accounts for the vast bulk of Russian gas exports. At current prices and volumes they generate approximately $60bn annually and account for roughly 12% of total Russian exports and not far off 10% of the federal budget. Clearly this is money Russia can ill afford to lose. In all likelihood Russia will announce a major move in May to diversify its gas exports when President Putin visits China. An agreement is expected to be signed calling for annual exports to China of 38bcm or 1.3 tcf of gas. This will involve constructing a pipeline from Western Siberia to north west China. Exports to China are not expected to begin in 2018 so in the short to medium Russia is locked into supplying Europe. Long term Russia will probably become considerably less dependent on gas exports to Europe than is presently the case.

Potential implications of the Ukraine crisis: Near term the key issue is the Gazprom payable, a cessation of Russian exports would send gas prices rocketing in Europe

The emergence of the Ukraine crisis in recent months has raised the spectre of a cut in Russian exports to Europe much as in 2009. The immediate issue concerns Ukraine's outstanding debt to Gazprom, which apparently is around $2bn. The fear is that Russia will attempt to enforce payment by shutting off the supply of gas to Ukraine and hence Europe. It should be noted, however, that President Putin has studiously avoided making an explicit threat along these lines. If Russian exports are halted through Ukraine, the issue then arises as to whether Europe could live with a 16% cut in gas supplies. The short answer is almost certainly 'no', particularly in winter. In all probability, however, in these circumstances, Russia might be prepared to supply extra gas via the Yamal and Nord Stream pipelines, thereby alleviating the problem. Any void remaining could possibly be filled by stepped-up LNG imports but at significantly higher cost. Note, there is no potential in Western Europe to boost gas supplies with the possible exception of Norway. In the event of disrupted supplies, the vulnerability for European consumers would clearly be a gas price surge in Europe along with spot shortages in those countries that are completely dependent on Russian supplies.

A more extreme scenario relates to a complete breakdown of relations between the west and Russia resulting in the cessation of all Russian gas exports. This would be a doomsday scenario that would send energy prices rocketing in Europe with highly negative consequences for the domestic economy. There would certainly be no easy way of offsetting the loss of almost 6tcf of gas imports from other sources either in Europe or outside without a substantial increase in prices. In the short term, one of the few measures that could be taken would be to greatly step-up coal-fired power generation. This would, of course, have highly negative implications for meeting the EU's cherished carbon emission targets, not only in the short term but quite possibly in the medium to long term.

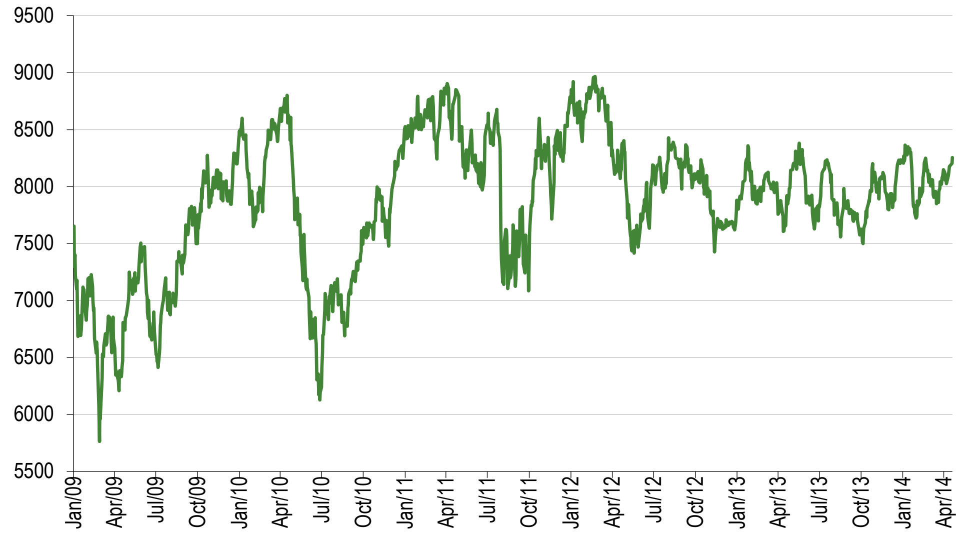
Given the horrendous implications for both sides of a cessation or even a sustained cutback in Russian gas exports to Europe, we probably have to assume that a grand bargain will ultimately have to be struck over Ukraine between the west and Russia (probably involving the neutrality of Ukraine). Note here, there are also considerable financial and reputational pressures on Russia to avoid a cessation or even a cut in gas exports to Europe. The working hypothesis probably has to be that Russian gas exports will continue uninterrupted in the near to medium term at least.

Oil and gas sector performance

UK: FTSE 350 O&G Index broadly flat so far in 2014, AIM O&G continues to slide

In absolute terms the trend in the FTSE 350 Oil & Gas Index of medium capitalisation UK-based oil and gas stocks (BP, Shell and the BG Group constitute 94% of the index) has been lacklustre so far in 2014. Performance, however, has been similar to the broader UK market. Between end December 2013 and mid April 2014 the index slipped by 1.0%, while the FTSE 100 fell by a slightly greater 2%. Compared with a year earlier, the FTSE 350 Oil & Gas Index at mid-April was up about 7%, which constitutes a slight outperformance of the 5.7% gain in the FTSE 100. Based on Bloomberg data, both indices trade on what are by today's standards hefty historic dividend yields of 4.2%. A further indicator of value is the FTSE 350 Oil & Gas Index's EV/EBITDA multiple (trailing earnings) of 5.3X against 7.7X for the FTSE 100, which is itself less than demanding. In a low inflation environment, the total return over the past year for the FTSE 350 Oil & Gas Index of about 11% should be considered a very solid performance.

Exhibit 41: FTSE 350 Oil & Gas Index



Source: Bloomberg

Looking at performance from a longer-term perspective the FTSE 350 Oil & Gas Index has trended flat to down since early 2011 largely in sync with the trend in Brent. Compared with the 2008 high, the index at mid April 2014 was down about 13%. Abstracting from the challenges faced by BP over Macondo, sentiment surrounding the majors has tended to be depressed in recent years by a combination of factors including cost pressures, heavy capital spending, production constraints, difficulties in boosting reserves and downstream margin pressures. Nevertheless, based on current economics, the majors retain the attraction of strong gross cash flow generation.

The AIM oil and gas juniors have continued to have a torrid time in the early months of 2014. Between end December 2013 and mid April 2014 the AIM Oil & Gas Index fell a hefty 17.7%. By contrast the AIM All Share declined by a considerably more modest 2.8% on the same basis. As of mid-April 2014, the AIM Oil & Gas Index was also down 18% from a year previously and was trading at roughly a four-and-a-half-year year low. Compared with the 2008 all-time high, the index in mid-April 2014 was down about 60%. The key issues surrounding the AIM juniors continue to be exploration and development disappointments and heavy cash needs. One of the most recent disappointments is Sterling Energy's dry Bamboo-1 well, offshore Cameroon. Significantly, the AIM juniors have little or no exposure to the hottest story in oil and gas, namely, the shale oil revolution in the US.

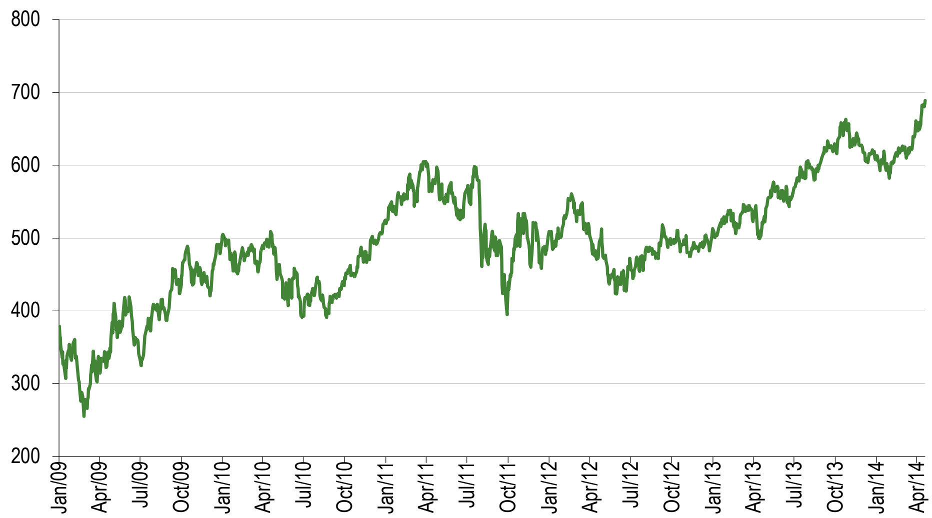
Exhibit 42: AIM Oil & Gas Index

Source: Bloomberg

USA: Strong performance by the E&P independents in early 2014

The US oil and gas sector in early 2014 has performed solidly to strongly depending on sub-sector. Setting the pace have been the mid-tier and large capitalisation stocks focused on exploration and development activity in North America. In the three-and-a-half months to mid April 2014 the S&P 500 Oil & Gas Exploration and Production Index, the benchmark for medium and large capitalisation oil and gas independents, showed a gain of a sizeable 9.5%. For comparison, the S&P 500 gained by 0.9% over the same period. Standout performers in the three-and-a-half months to April were EOG Resources and Anadarko Petroleum with gains of 21.9% and 24.3% respectively. Outside the S&P 500 Oil & Gas Exploration and Production Index the Bakken pioneer, Continental Resources, rose by 20% over the same period and currently is trading 82% above year-ago levels. For comparison, over the past year the S&P 500 Oil & Gas Exploration and Production Index has risen by 35.5%, while the S&P 500 is up 20%.

Exhibit 43: S&P 500 Oil & Gas Exploration and Production Index



Source: Bloomberg

The medium and large capitalisation E&P stocks generally continue to benefit from positive volume trends, largely related to buoyant development activity in shale oil plays. A further positive over recent months has been a firming tendency in US oil and gas prices. Specifically in the case of Anadarko, a perceived positive for the stock of late was the settlement with the Justice Department over a longstanding environmental contamination case relating to the 2006 acquisition of Kerr-McGee. Anadarko has agreed to pay a hefty $5.2bn for clean-up costs but this was at the low end of the range of expectations. Furthermore, settlement of the case has eliminated a major area of uncertainty surrounding the stock.

In early 2014 the broadly based S&P 500 Oil & Gas Index, which includes the majors plus the large independents and refinery groups, turned in a more pedestrian performance than that of the S&P 500 Oil & Gas Exploration and Production Index. Performance nevertheless has been very solid both absolutely and relatively. In the three-and-a-half months to mid-April the former Index firmed 2.8% and is currently up 21% over the past year.

Over the past month or so the majors have been discovered as value plays. Based on Bloomberg data, Exxon and Chevron sell on historic dividend yields of 2.5% and 3.2% and EV/EBITDA multiples (trailing earnings) of 8.0x and 5.8x respectively. Both dividend yields comfortably exceed the S&P 500's 2.0% while the multiples are decidedly modest relative to the S&P 500's 10.6x. For extra perspective, BP and Shell sport dividend yields of an even more enticing 5.3% and 5.0% respectively. Their EV/EBITDA multiples, however, are in line with that of Chevron.

A key area of strength in the energy patch in 2013 was the refinery sector. The benchmark S&P 500 Refinery Index climbed 43 % for the year driven by a very favourable business backdrop in terms of internationally competitive feedstock availability, historically high utilisation rates, strong volume growth and internationally highly competitive natural gas prices (both a feedstock and a fuel). These factors have continued to apply in 2014 resulting in a very solid performance for the Refinery Index with a 3.5% gain in the first three-and-a-half months. In mid April 2014 the same index was up 30% on a year earlier.

Exhibit 44: S&P 500 Oil and Gas Index scale label

Source: Bloomberg

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