# Oil & gas macro outlook

## North America is shifting the supply needle

Oil & gas

**28 January 2014**

**We continue to believe that the near- to medium-term outlook for crude oil prices is bearish. Non-OPEC controlled supply is growing strongly driven by North America, and barring unplanned outages should run ahead of modest global demand growth. The key wildcard is OPEC's response to the growing supply pressure. It is worth noting in this context that Iraq has the freedom and probably the capacity to boost output, and Libya and Iran both wish to increase production as circumstances allow. Significantly, Saudi Arabia seems to be suggesting that it will not necessarily offset production gains elsewhere within OPEC. It also has no interest in providing a price umbrella for relatively high-cost non-OPEC producers.**

## Supply/demand position: Non-OPEC supply surge

Non-OPEC supply including OPEC natural gas liquids (NGLs), which are not subject to quota, is estimated by the EIA to have increased by about 1.6mmb/d in 2013 driven by Canada and particularly the US. This comfortably exceeded global demand growth of an estimated 1.0-1.2mmb/d. Supply growth outside OPEC looks like being particularly robust in 2014. A record gain of 1.9mmb/d or 3.6% is forecast based on EIA data with North America again very much to the fore. Including OPEC NGLs the total increase in non-OPEC controlled supply could be an unprecedented 2mmb/d plus in 2014. Non-OPEC supply growth will probably ease in 2015 but is still likely to be historically robust at about 1.6mmb/d including OPEC NGLs. We believe global demand growth at perhaps 1.0-1.2mmb/d will fall significantly short of the potential supply gains in 2014/15. OPEC has belatedly acknowledged the significance of the North American supply surge and is now expecting a reduced 'call' on its crude production in 2014/15.

## Light crude spreads: LLS swings to discount

The big story in the fourth quarter of 2013 was light crude spreads. The key developments were the resurfacing of a sizeable WTI discount to Brent and the swing from the historical premium to a significant discount of LLS, the Gulf Coast benchmark, to Brent. The WTI discount widened between the third and fourth quarters of 2013 from $4.2/bbl to $10.9/bbl, while LLS on the same basis swung from parity to Brent to a discount of $7.4/bbl. In mid-January 2014 WTI and LLS were trading at discounts to Brent of $12/bbl and $1/bbl respectively. The underlying issue behind the recent developments in spreads was a build-up of supply in the Mid-Continent and increasingly along the Gulf Coast. WTI and LLS are likely to trade at significant structural discounts to Brent for the foreseeable future.

## Price forecasts: Brent unchanged, WTI downgraded

We are leaving our Brent forecast for 2014 unchanged at $103/bbl, down 5% on 2013. We forecast a similar decline for 2015. The downward trend stems from the potential for an easing of geopolitical tension and our bearish supply/demand balance scenario. Reflecting the US supply build-up, we have reduced our WTI forecast for 2014 from $96.5/bbl to $94.0/bbl. We forecast a further softening to $89.5/bbl for 2015. The forecasts would be subject to downside risk in the event of an early large-scale resumption of Libyan and Iranian exports.

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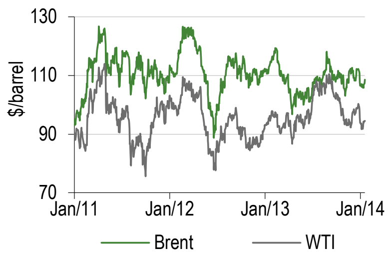
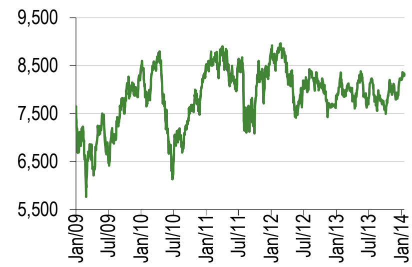
**WTI vs Brent**




**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 | 108.6 | 3.73 |
| 2014e | 94.0 | 103.0 | 4.04 |
| 2015e | 89.5 | 98.0 | 4.20 |

Note: Prices are yearly averages.

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## Contents

# Highlights

Highlights of this report include:

- Robust non-OPEC production growth.
- Very strong production trends in the US and Canada.
- OPEC production slips in 2013 to around the call.
- OPEC and IEA belatedly recognise the significance of the shale revolution.
- The key wildcard for 2014/15 is OPEC production.
- Signs of firmer OECD demand in the second half of 2013 driven by the US.
- Non-OPEC output growth should comfortably exceed global demand gains in 2014/15.
- WTI is in mild contango in the front month, Brent in pronounced backwardation.
- WTI discount widens again in the fourth quarter of 2013.
- LLS Gulf Coast benchmark swings from traditional premium to a significant discount to Brent
- Bakken discount to WTI narrows sharply in late 2013
- Brent had its first down year in 2013 since 2009.
- Regulatory and political changes pave way for major shale oil/gas projects in Argentina.
- 2014 Brent price forecast unchanged, WTI downgraded.
- Relatively high shale play drilling/completion costs suggest a WTI price floor of $75-85/bbl.
- Gulf Coast crack spreads remain relatively high historically.
- The US natural gas production and domestic consumption trend is flattening.
- US pipeline gas exports to Mexico surging.
- US NGL demand supported by exports and domestic petrochemicals activity.
- US dedicated oil rig count flattens at a historically high level.
- US Henry Hub price forecast broadly unchanged for 2014.
- Semblance of viability for US dry gas producers in early 2014.
- US wet gas producers comfortably profitable at fully accounted level.

## Executive summary

**Recent oil price developments:** International light crude prices trended broadly flat during the fourth quarter of 2013. Brent closed the year at $110.8/bbl, which was down 1% on a year previously. For 2013 as a whole Brent averaged $108.6/bbl, 3% below a year earlier. This was the first down year for Brent since 2009. In early January 2014 the trend weakened with Brent falling to roughly $106/bbl at mid month. Depressing sentiment was growing evidence of buoyant non-OPEC supply growth driven by the US and an easing of Libyan supply concerns. WTI also trended broadly flat in the fourth quarter and ended the period at $98.4/bbl, up 7% on a year earlier. Contrasting with Brent the average for WTI in 2013 of $98.0/bbl was 4% higher than in 2012. In common with Brent, WTI slipped in January hitting a recent low of around $92/bbl.

**WTI-Brent spread:** The WTI discount to Brent widened markedly between the third and fourth quarters of 2013 from $4.2/bbl to $10.9/bbl. In late November the WTI discount approached $20/bbl after having been virtually eliminated completely at times in the third quarter. At 2013 year end the WTI discount stood at $12.4/bbl and remained at about this level through mid January 2014. On average WTI sold at a discount of $10.6/bbl in 2013, sharply narrower than the $17.8/bbl of 2012. The widening WTI discount in the fourth quarter of 2013 reflected a combination of the continuing strong upward trend in US production, which tended to depress WTI, and international concerns, especially surrounding Libya, that supported Brent. Supply issues combined with transportation bottlenecks may be pointing to an underlying structural WTI discount of $10/bbl plus in the near to medium term. A particularly interesting development in recent months has been the unprecedented swing from premium to discount in the LLS-Brent spread. The LLS discount in the fourth quarter of 2013 averaged $7.4/bbl. The swing to an LLS discount is symptomatic of the heavy build-up of supplies along the Gulf Coast.

**Non-OPEC output:** Non-OPEC crude oil output growth in 2013 was buoyant. According to the EIA, there was a gain of 2.7% or 1.4mmb/d to 54.1mmb/d, which was at or close to record levels. Growth was closer to 1.6mmb/d including OPEC NGLs, which are not subject to quota restrictions. Overall the growth in non-OPEC controlled production in 2013 constituted one of the largest gains over the past 10 years. The gain in non-OPEC output was almost all attributable to the US and Canada. The EIA is looking for non-OPEC output growth in 2014 of 1.94mmb/d or 3.6% to a record 56.0mmb/d. Including OPEC NGLs the gain could be over 2mmb/d. North America is expected to account for about 75% of the gain in non-OPEC crude output in 2014 with the key factors continuing to be the rapid development of US and Canadian tight reservoir formations and the Athabasca oil sands in Alberta. For 2015 the EIA is forecasting slower but still substantial non-OPEC output growth of 1.6mmb/d or 2.6%. North America will probably again account for about 75% of growth.

**US output:** Based on EIA data, US crude oil production rose between 2012 and 2013 by 1.01mmb/d or 16% to 7.50mmb/d. Total oil production including ethanol, biodiesel and NGLs in 2013 averaged 11mmb/d (+12% from 2012). For the four weeks to 10 January 2014, production averaged 8.13mmb/d, the highest level since October 1988 and up 16% on a year earlier. Production continues to be driven by intensive development activity in the shale and tight reservoir formations of the Great Plains and Texas. The EIA is forecasting US crude oil output gains of 14% in 2014 and 9% in 2015. The forecast for 2014 constitutes a slight upgrade from a few months ago. Forecast production in 2015 of 9.3mmb/d would be the highest yearly average since 1972.

**OPEC output:** OPEC crude oil production weakened noticeably in the fourth quarter of 2013. For the period production averaged 29.6mmb/d, about 1mmb/d below the recent August high. The key issues driving the recent weakness were stronger than normal seasonal demand influences in the Middle East, continuing unplanned outages in Libya, maintenance related outages and softening underlying export demand related to the strong production growth outside OPEC. Despite the fourth-quarter weakness OPEC crude production averaged 30.2mmb/d in 2013, only slightly above the 30mmb/d target. Compared with 2012, OPEC production in 2013 was off 1mmb/d. OPEC belatedly perhaps has acknowledged the impact that rising non-OPEC production is having on the demand for its crude. Presently, OPEC is forecasting the 2014 call or demand to be 29.6mmb/d, down 0.3mmb/d on 2013. How OPEC will react to rising non-OPEC production is a major wild card especially as Iraq, Iran and Libya have all expressed a desire to substantially boost output.

**Global demand:** The trend in global oil demand firmed in the second half of 2013 driven by the OECD world outside Asia Pacific. The tendency has been most pronounced in the US. For 2013 as a whole oil demand grew by 1-1.2mmb/d or about 1.4% to 90-91mmb/d. Demand growth looks to be increasing at a moderate pace in 2014/15 assuming consensus economic growth forecasts and the structural factors tending to depress usage. The EIA is currently forecasting demand growth globally of 1.2mmb/d (1.3%) in 2014 and 1.4mmb/d (1.5%) in 2015. OPEC takes a slightly more bearish view for 2014 with a gain of 1.1mmb/d.

**Oil supply/demand balance:** Non-OPEC controlled output growth probably comfortably exceeded global demand growth in 2013. The surplus could have been about 0.4mmb/d. Allowing, however, for lower OPEC supply there may have been an overall deficit of 0.5mmb/d in 2013. Abstracting from major unplanned outages non-OPEC controlled output growth in 2014 should easily exceed global demand growth. The surplus could be in the region of 0.6mmb/d based on EIA forecasts. The key issue for the balance in 2014/15 will probably be OPEC production. We believe it will be difficult for OPEC to cut production in 2014 if Libya, Iraq and possibly Iran boost output as desired.

**Argentina:** Outside North America the shale revolution is most advanced in Argentina. Recent changes in the regulatory and political backdrop have paved the way for major development projects to commence in the Neuquen Basin's world class Vaca Muerta formation. In recent months Chevron, Wintershall and Dow Chemical have all announced JVs with state-controlled YPF, while Shell has said that it is tripling its investment in the Vaca Muerta formation.

**Crude oil price forecasts:** The fundamentals are pointing to a potential slide in international oil prices in 2014/15 reflecting strong growth in non-OPEC supply and moderate demand growth. We are leaving our Brent 2014 forecast of $103/bbl (down 5% on 2013) unchanged. We forecast a further dip to $98/bbl for 2015. In the case of WTI we are modestly downgrading our 2014 forecast from $96.5/bbl to $94.0/bbl reflecting greater than expected carryover weakness from 2013 and the robust supply trend. A decline in WTI of a further 5% to $89.5/bbl is forecast for 2015. Relatively high shale play drilling costs suggest a WTI floor in the $75-85/bbl range.

**US natural gas fundamentals:** 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 has been 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 trended strongly higher in the closing weeks of 2013 and in January 2014. The benchmark Henry Hub price has recently exceeded $4.50/mmBtu, around a 30-month high. At this level most dry gas producers should be capable of at least generating a comfortable cash contribution. Wet gas producers in the liquids-rich zones of the Marcellus and elsewhere are probably capable of generating very comfortable fully accounted profits at early January economics. Our 2014 Henry Hub price forecast is broadly unchanged at $4.04/mmBtu, up 8% on a year previously. A further gain of 4% to $4.20/mmBtu is forecast for 2015 based on an assumed moderate tightening in the supply/demand balance.

## Crude oil market dynamics

### Price overview

#### Market developments: Flat trend since early 2011

**Recent months in retrospect:** International crude oil prices trended broadly flat in the fourth quarter of 2013. Brent closed the year at $110.8/bbl, roughly the same level as a year earlier. and down $10-12/bbl from the spot highs of mid February and end August. Interestingly, the trend in international oil prices has now been flat since early 2011. Effectively, prices have traversed a high plateau over the past three years in both nominal and real terms.

**Exhibit 1: Brent crude oil price trend**


Source: Bloomberg

In the closing months of 2013 oil market sentiment was dampened by two key factors. These were the continuing robust build-up in non-OPEC output driven by the US, and an easing in Middle East geopolitical tension. Speculation in recent months over the potential tapering of the Federal Reserve's quantitative easing programme has probably also tended to dampen sentiment as it has for commodities as a whole. The easing of geopolitical tension has stemmed from two critical events. Firstly, the avoidance of western military intervention in Syria following a Russian proposal in September to place Syria's chemical weapons arsenal under international control. The second event was the accord reached in November between the five permanent members of the UN Security Council plus Germany (five + one) and Iran to curb the latter's nuclear programme. Given that the earlier price spikes in 2013 were attributable in large part to a build-up in Middle East tension, the accords concerning Syria and Iran were highly significant in terms of the oil market.

Tending to offset the bearish influences in the closing months of 2013 were several factors, the most important of which was the ongoing quasi-civil war/insurrection in Libya. At its core this has pitted armed secessionist/federalist orientated militias in the east of the country against the central government. In support of their cause for more autonomy and a greater share of the spoils from exports, the federalist forces have been blockading Libya's major export oil terminals and refineries since July. This has resulted in production and exports being reduced from earlier in 2013 by approaching 1mmb/d. According to industry sources, Libyan production in early December was running at not much more than 0.25mmb/d while refined product was being imported. More recently production appears to have picked up to 0.5-0.6mmb/d. The loss of Libyan exports has effectively been made good by stepped-up output at other OPEC producers, notably Saudi Arabia and rising non-OPEC production. Nevertheless, the market has found developments in Libya disconcerting from time to time in recent months.

Negotiations between the federalists and central government had been expected to lead to the re-opening of terminals in December, but no agreement was reached. Economic pressures do however appear to be increasing on both the federalists and the central government so an agreement on re-opening the terminals would appear likely in the coming weeks. Significantly, following a tentative agreement between a rebel group and the government, production was re-started at the el-Sharara oilfield in the west of Libya in early January. Overall, however, the situation in Libya remains volatile. In addition to Libya, signs of a firming OECD economy and a slightly more buoyant demand backdrop over recent months helped support oil market prices in late 2013.

South Sudan again entered the news in late 2013 following an outbreak of warfare between rival factions. This tended to provide another prop for oil prices but in reality is not of major importance to oil markets. Oil output had only been reinstated in September following a prolonged dispute with Sudan over pipeline fees. As of early January, production was still running at about 0.2mmb/d from the northern province of Upper Nile. This was not greatly down from the recent production peak of 0.25mmb/d. Prior to the beginning of the dispute with Sudan over pipeline fees in early 2012, production collectively for Sudan and South Sudan had been running at around 0.4mmb/d, with the south accounting for roughly 75%. Historically, the bulk of the output has been exported to China and India. Doubtless production in South Sudan will be restarted in due course. It has no other source of cash.

**Exhibit 2: WTI crude oil price**


Source: Bloomberg

**Spreads were the key story in late 2013 –** Arguably the key story in oil markets in the closing months of 2013 revolved around product spreads rather than absolute price levels. Once again, in the fourth quarter the discount of the US continental light crude benchmark WTI to Brent widened noticeably, reflecting burgeoning shale oil output, a recurrence of transport bottlenecks and, early in the period, an unusually large number of refinery outages. The WTI discount actually widened from approximate parity at the low point in July to approaching $20/bbl in November. Over the balance of 2013 the WTI discount narrowed but at end year was still a highly significant $12.4/bbl.

On the product spread front, perhaps, the most significant development in recent months has been the decisive swing in Light Louisiana Sweet (LLS), the Gulf Coast light crude benchmark, from the historical premium to a sizeable discount to Brent. During the fourth quarter of 2013 the discount was around $10/bbl on occasion. The swing was not unexpected and reflects the build-up of supply along the Gulf Coast following a series of logistical upgrades. The upshot of the newly apparent LLS discount is twofold. Firstly, those Gulf Coast refineries capable of handling light crude have been given a highly significant competitive boost; and secondly, competing imported light crudes along the Gulf Coast have been forced down in price. In future, light crude suppliers selling into the US will have to benchmark WTI/LLS and not Brent and the West African crudes. Indeed, increasing US supplies should, all other things being equal, bring down light crude prices throughout the Atlantic in due course.

**But for the full-year North America is again the top story –** A year or so ago we proposed North America as the top petroleum industry story of 2012. This was based on surging production from shale and other tight (low permeability) reservoir formations located in the US Great Plains states and Texas as well as the oil sands of Alberta. For 2013 we would again nominate North America as the leading story. According to Energy Information Agency (EIA, the statistical arm of the US Department of Energy) data, US oil production in 2013 probably increased by 1.2mmb/d (+11%) while in Canada there was a gain of 0.34mmb/d (+9%). Combined, the US and Canada accounted for all the increase in non-OPEC output in 2013. In this context it should be noted that until a few years ago US oil production, especially onshore, was considered by most observers to be in irretrievable decline.

Technological innovations have revolutionised the US production backdrop over the past few years. These have primarily included the widespread application to tight reservoir formations of horizontal drilling and high-pressure multi-stage fracture stimulation (fracking) over long distances of up to around 10,000 ft. A further innovation has been the use of what Continental Resources, the leading operator in the North Dakota Bakken formation, has termed ECO-PAD drilling. This enables four wells to be drilled from one location with the aim of developing two formations simultaneously on two separate spacing units. Given the ability of these innovations to enable the economic exploitation of previously un-exploitable yet massive reservoir formations, we believe they are among the most influential petroleum industry technological developments since the Hughes twin-cone rotary drill-bit in the early 20th century.

A key difference between 2012 and 2013 regarding the US shale oil revolution is that in 2013 it has rapidly gained in acceptance. The sceptics, particularly in the form of the International Energy Agency (IEA, the energy watchdog for the OECD) and OPEC, have belatedly acknowledged the significance of the phenomenon. Significantly, OPEC has recently indicated that it expects shale oil development in North America over the next few years to depress demand for its oil below previous expectations.

## Supply-demand dynamics

### Non-OPEC supply: Buoyant trend driven by North America, record level

**2013 in retrospect:** Non-OPEC oil production remained buoyant in the closing months of 2013 and for the year as a whole was running at record levels. The EIA estimates non-OPEC output at 54.68mmb/d and 55.26mmb/d in the third and fourth quarters respectively, which would translate into year-on-year gains of 4.6% and 3.3% respectively. For 2013 as a whole, output is forecast at 54.13mmb/d, up on a year previously by 1.42mmb/d or 2.7%. This is marginally down on the forecast of three months ago but considerably above that of 1.1mmb/d made earlier in 2013. The absolute increase is also one of the largest in the past 10 or more years. In addition, the EIA expects OPEC's supply of natural gas liquids (NGLs), which is not subject to quota, to contribute another 0.2mmb/d, implying a total increase in the supply of liquids free of quota of about 1.6mmb/d. The IEA and OPEC have moderately lower increases for 2013 at 1.4mmb/d and 1.3mmb/d respectively.

As we have already noted, the gain in non-OPEC production in 2013 has been very much driven by Canada and especially the US. Other areas showing growth of at least 0.1mmb/d in 2013 were Russia, Ghana and Sudan/South Sudan. Russia has benefited from development activity in Eastern Siberia, while Ghana has gained from a build-up at the new Jubilee field. The positive for Sudan/South Sudan was the re-commencement of production following an earlier dispute between the two countries on pipeline costs. The key area of weakness in 2013 was the North Sea where the EIA estimates a drop from 2012 of 0.18mmb/d or 4.5%. Importantly, Mexico, a major area of weakness in recent years, appears to have had some success in stabilising output in the second half of 2013. Generally the incidence of unplanned outages in the non-OPEC world in 2013 was significantly less than in 2012.

A key disappointment in recent months has been the performance of the giant Kashagan field in the Kazakh sector of the Caspian Sea. Production here commenced early in September but following a series of gas leaks had to be halted shortly thereafter. The problem appears to be pipework sulphide stress cracking reflecting high concentrations of hydrogen sulphide. A resumption of production at Kashagan is not expected until the second quarter of 2014 at the earliest.

**Near-term outlook:** Non-OPEC oil production looks like being particularly robust in 2014 subject to the usual caveat of no major unplanned outages. The EIA is forecasting a gain of about 1.9mmb/d or 3.6%. This would imply production of 56.1mmb/d. Based on EIA data, OPEC NGLs could show incremental growth of 0.1mmb/d, thereby taking the overall gain in the supply of liquids not subject to OPEC quota to 2mmb/d. Compared with three months ago, the EIA's 2014 production forecast is up by 0.3mmb/d. Once again, non-OPEC output growth is expected to be driven by North America. The contribution from this source is forecast by the EIA at around 1.3mmb/d with the US and Canada accounting for 1.1mmb/d and 0.2mmb/d respectively. Elsewhere, the key areas of strength identified by the EIA are the North Sea, Central and South America (Argentina, Brazil and Colombia), Africa (Sudan/South Sudan and Ghana) and China.

In the case of the North Sea, the EIA is calling for an increase in 2014 of 0.15mmb/d or 5.2% to 3.02mmb/d. If achieved, this would be the first annual gain in North Sea output since 2000. Between 2000 and 2013 output in the North Sea fell by a hefty 55% (Norway -45%, UK -67%, Denmark -50%), reflecting maturing fields, rising costs and in recent years a high incidence of unplanned outages. The upturn in 2014 stems from stepped-up development activity particularly in the UK sector. Two key UK projects scheduled to come on-stream during 2014 are Total's Laggan-Tormore (west of Shetland) and Nexen's Golden Eagle (adjacent to the Buzzard field). Production in 2014 is expected by the EIA to rise by 2% in Norway and 8% in the UK.

According to the EIA, South and Central America will show moderate yet significant production growth of about 3.5% in 2014. Taking the largest non-OPEC producer, Brazil, a gain of 2.6% to 2.78mmb/d is forecast. Production from the massive pre-salt discoveries made about 300km offshore late in the last decade is still modest, but should start gathering pace in 2015/16. The objective of the Brazilian government is to boost domestic oil production to over 5mmb/d by 2021 with exports at the same date of 2.25mmb/d. The latter compares with about 0.5mmb/d currently and would establish Brazil as a major exporter on the world scene.

### OPEC supply: Non-OPEC output growth is reducing the call on OPEC

OPEC crude oil production was buoyant through the first nine months of 2013, averaging 30.4mmb/d based on what OPEC refers to as secondary sources. However, the trend weakened noticeably in the fourth quarter of 2013. For the period output averaged 29.6mmb/d, around 1mmb/d below the recent August 2013 high. Declining output of late appears to reflect a combination of negative seasonal demand influences in the Middle East (falling power station burn-rate), the continuing unplanned outages in Libya, maintenance issues and softening demand due to the strong growth in production outside OPEC. Significantly, Saudi Arabia's output has dipped from a recent high of 10.1mmb/d in August to 9.6mmb/d in December. Iraq's output, as expected, fell sharply between August and September with a decline of 0.4mmb/d to 2.8mmb/d due to the upgrading of the southern export terminal facilities, but subsequently there has been a strong rebound. By end year, Iraq's output was back to 3mmb/d and within striking distance of the second quarter high of 3.1mmb/d. A further gain in output to perhaps 3.5mmb/d is a possibility by end 2013 or early 2014 as the revamped Majnoon field commences operations.

For 2013 as a whole OPEC crude oil production averaged around 30.2mmb/d (based on OPEC's secondary sources) or marginally above the official 30.0mmb/d target and down 1mmb/d on 2012. After running comfortably in excess of the OPEC call (world oil demand less non-OPEC supply and OPEC NGLs/non-conventionals) through the first half of 2013, OPEC crude production appeared to be only marginally ahead of demand in the third quarter. Interestingly, November's OPEC's crude output was pretty much in line with the theoretical call or demand. For 2013 as a whole, OPEC put the call for its crude at 29.9mmb/d or slightly below the implied production rate.

OPEC has acknowledged that rising non-OPEC supply is likely to exert downward pressure on the demand for its crude in 2014 in the absence of a surge in world consumption. Presently, OPEC is forecasting the 2014 call to average 29.6mmb/d, down 0.3mmb/d from 2013. The critical issues for OPEC now are twofold:

- Does it facilitate a drop in production to accommodate falling demand, or do the members simply compete with one another for market share? Note: this is not just an issue for 2014 but quite possibly for the balance of the decade.
- How does it allow for the desire of several of the members to radically increase output over the next few years, in what could be a declining market for OPEC crude? Iraq has the most ambitious objectives and is looking to boost production to 4mmb/d by end 2014 and 9mb/d by 2017. Assuming it can rid itself of sanctions, Iran has indicated that it would like to boost output in the near term to 4mmb/d from about 2.7mmb/d presently, while Libya has expressed a desire to rapidly increase production to 1.5mmb/d plus once the export terminals are reopened.

Significantly, Saudi Arabia has indicated that it will not necessarily meekly accommodate the objectives of the other OPEC members to increase production. In the final resort, these objectives are almost certainly too bullish, but there is nevertheless likely to be significant upward pressure on production in the near to medium term from the likes of Iraq, Libya, Angola and possibly Iran. A wildcard event could, of course, provide some relief. One possibility might be a pronounced deterioration in the economic and industrial backdrop in Venezuela stemming from the distortions created by the increasingly autarkic policy stance of the ruling socialist party. A particular concern relates to the constrained availability of dollars at the official exchange rate and actual and potential restrictions on importing critical petroleum industry supplies and services. Such restrictions could at some point result in an acceleration in the downward trend in Venezuela's oil production that has been apparent over the past 10 or so years. Presently Venezuela produces around 2.4mmb/d.

### Global demand: Firming trend in H213

**2013:** Oil demand globally appears to have firmed slightly compared with the expectations of a few months ago driven by the OECD world outside the Asia-Pacific region. The US has been very much to the fore, but a more bullish trend has also been apparent in Europe. The explanation would appear to be largely attributable to the macroeconomic backdrop, which since the third quarter has gained a little upward momentum in Europe and particularly the US. Constraining the overall firming tendency in OECD demand has been a slowdown in Japan related to a switch from fuel oil and crude in power generation to considerably lower-cost coal.

It would appear that global oil demand in 2013 rose between 1mmb/d and 1.2mmb/d or 1.4% to about 90-91mmb/d. The EIA and IEA are both at the top of the range and OPEC the bottom. Reflecting signs of firming OECD demand, all three have recently raised their 2013 full-year forecasts. Estimated demand growth in 2013 was greater than in 2012 but in line with pattern of recent years. Broadly speaking oil demand in 2013 was flat in the OECD and up 2.5% or so elsewhere in the world. Within the OECD, declines in Europe and Japan of roughly 1% and 3% respectively were offset by gains in North America and elsewhere of approximately 2%. Significantly, the decline in Europe was the smallest in years. As has been the pattern for a number of years, growth outside the OECD was driven in 2013 by China, other Asia, Middle East and Latin America, where there were year-on-year gains of approximately 3.4% (0.38mmb/d), 1.8%, 3.8% and 3.6% respectively. Note that China's growth rate in 2013 was significantly less than the gain in 2012 of 4.3% or 0.43mmb/d. A combination of improving fuel efficiency, officially inspired conservation measures, a slowing economy and a gradual shift in the weighting in the economy to less energy intensive sectors is taking its toll on petroleum demand growth in China.

An interesting development over recent months in the context of global oil demand has been attempts by several governments in the developing world to cut fossil fuel subsidies. Cases in point have been Indonesia and Malaysia, which hiked gasoline prices by over 40% in the second half of the year. Egypt and India are reputedly contemplating similar measures. The rationale is the acute strain that subsidised fuel is placing on public sector budgets, and the growing pressure in many developing countries to reduce sizeable budget deficits. Lower fossil subsidies constitute a potential vulnerability to oil demand forecasts in the non-OECD world in the years to come.

**2014/15:** Oil demand globally looks like continuing at a modest pace in 2014/15 based on consensus economic growth forecasts, and after taking into account the forces that are tending to depress underlying usage patterns. The EIA is calling for growth in 2014 of 1.2mmb/d or 1.3%, while OPEC is more bearish with a forecast gain of just under 1.1mmb/d. The pattern regionally is similar to 2013 with flat to marginally lower demand in the OECD, more than offset by a gain of just under 3% elsewhere in the world. Interestingly, the EIA is forecasting oil demand only marginally higher in the US in 2014, despite the assumption of higher economic growth. The explanation is an expected slowing in highway travel after a recent unexpected acceleration, and the improving fuel efficiency of the light vehicle fleet.

For 2015 the EIA is looking for global oil demand growth of 1.37mmb/d or 1.5% to about 93mmb/d. Not surprisingly this is again expected to be driven by the non-OECD world. Consensus oil demand growth forecasts for 2014 and 2015 are, of course, all substantially below those for the world economy, which has generally been the case for many years. For reference, world GDP growth is forecast by the IMF at 3.1% in 2013 and 3.6% in 2014. It should be noted that even in the non-OECD world oil demand growth is significantly lagging economic growth in many instances. For example, China's demand growth of perhaps 3.7% in 2014/15 will probably not be more than 50% of the growth in the economy in those two years. The lag to economic growth stems from a combination of improving fuel efficiency, particularly in transport applications, and fuel substitution and conservation measures. Specifically in the OECD world, there may also be some demographic and lifestyle developments that are reducing transportation fuel usage. The underlying catalysts for these trends have been a combination of the upward trend in the real price of oil, technological advances and tightening regulation, particularly in terms of light vehicle fuel economy and the pressure on non-OECD governments to sharply cut fossil fuel subsidies.

We believe that the oil demand forecasts for 2013 and 2014 made by the likes of the EIA and IEA are perfectly plausible assuming that the world economy grows in line with the IMF's expectations. A potential vulnerability for 2014, however, is a weaker non-OECD economy than generally expected presently. In recent months a number of the larger developing economies such as Brazil, India and Turkey have performed worse than expected, hit by a combination of high indebtedness, budgetary pressures, falling commodity prices and balance of payments deficits. If these issues persist, they could lead to negative surprises on the oil demand front in 2014. Specifically in the case of China, it is not at all clear how painless the policy will be of re-orientating the economy from investment to consumption. It is quite possible that Chinese GDP growth could easily be nearer 6% than the consensus view of 7% or so in 2014/15. In this event oil demand in China might be 0.1-0.2mmb/d lower than assumed by consensus forecasts currently.

**ExxonMobil's long-term demand outlook:** ExxonMobil recently presented its annual review of the long-term outlook for the energy business. Some key findings on the demand side of the equation are as follows:

- World primary energy growth: 1.5% pa 2010-25, 0.5% pa 2025-40, 1.0% pa 2010-20.
- Oil demand growth globally: 1.1% pa 2010-25, 0.5% pa 2025-40, 0.8% pa 2010-40.
- Only a modest slip in oil's weighting in the primary energy mix globally between 2010 and 2040, from 34% to 32%.

- Oil remains the largest constituent of the global primary energy mix between 2010 and 2040. Combined, oil and gas in 2040 account for 58% of the energy mix, up from 56% in 2010.
- Coal's share of the energy mix drops from 26% in 2010 to 19% in 2040.
- Nuclear's share of the energy mix rises from 5% in 2010 to 8% in 2040.
- Renewable's share of the energy mix rises from 12% in 2010 to 15% in 2040.

For comparison, ExxonMobil's energy forecasts between 2010 and 2040 are based on world GDP growth of 2.8% pa (OECD 2.0% pa, non-OECD 4.4% pa) and population growth of 0.9% pa. Long-term energy consumption is therefore expected to continue lagging the broader economy by a wide margin. This is manifested by an approximate halving in ExxonMobil's estimate of world GDP energy intensity between 2010 and 2040 from 11.9mBtu to 6.1mBtu/$ GDP. For the OECD there is a decline from 7.7mBtu to 3.3mBtu/$ GDP.

### Global supply/demand balance: Non-OPEC output growth outpacing global demand

Including both OPEC and non-OPEC supplies, the oil market globally appears to have been in significant surplus of a million or so barrels a day in the first half of 2013. A tightening followed in the second half and particularly the fourth quarter of 2013, as OPEC production declined and demand firmed. However, this would appear to have been modest. In fact, the market may have been not far away from balance in the second half. Helping keep the market close to equilibrium in recent months has clearly been buoyant non-OPEC production.

Looking at the supply-demand relationship purely in terms of the growth in world demand versus that of non-OPEC production plus OPEC NGLs, the market was probably easily in surplus in 2013. Based on EIA data this may have been about 0.4mmb/d. After allowing for lower output of OPEC crude, the EIA forecasts there may have been an overall deficit of about 0.5mmb/d in 2013.

In the absence of major unplanned outages, the prospective growth in non-OPEC output plus OPEC NGLs looks like comfortably exceeding global oil demand in 2014. The reason is surging non-OPEC supply. Using the EIA's data, the surplus could be around 0.6mmb/d. As already discussed, the key issue for the supply-demand balance in the near term is OPEC production. We find it difficult to believe that OPEC will be able to cut production in a major way in 2014, assuming that Libya brings back on-stream its presently shuttered facilities and Iraq boosts output as planned. A lifting of sanctions on Iran would greatly compound OPEC's problem, and in all probability make a cut in its production in 2014 virtually impossible. The upshot is that we could also be looking at a highly significant supply surplus on an all-encompassing broad definition of the oil market in 2014. We believe that unless there are major unplanned outages either within or outside OPEC, the situation in the oil market could be analogous to the mid-1980s. At that time the OPEC cartel was overwhelmed by burgeoning oil production from the North Sea and Mexico.

## US scene

### Oil production and imports: Production strongly upward, imports continue to fall

**Overall picture:** The underlying trend in US crude oil production remains strongly upward, although the pace has ebbed somewhat from earlier in 2013. Production continues to be driven by the rapid development of the shale and tight reservoir formations of the Great Plains and Texas. Significantly, production exceeded 8mmb/d in late November for the first time since January 1989. For 2013 as a whole, US crude oil production averaged 7.50mmb/d, 16% or 1.01mmb/d above a year previously and 50% up on the 2008 low. Total oil production in 2013 including ethanol, biodiesel and NGLs was 10.99mmb/d, up 12% on 2012.

**Exhibit 3: US crude oil production**


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

Based on EIA data, US production in the four weeks to 10 January averaged 8.13mmb/d, the highest level since October 1988. Compared with a year ago there was a gain of 1.13mmb/d or 16.2%. Tight reservoir plays such as the Bakken in North Dakota and Montana and the Eagle Ford and Permian Basin in Texas are estimated by the EIA to have contributed about 3.5mmb/d in 2013, representing a gain of 55% from 2012. Constraining production in 2013 was flat or declining output in the mature and large petroleum provinces of Alaska, California and the Gulf of Mexico.

For 2014 the EIA is forecasting US crude oil production of 8.54mmb/d, a gain of 14% from 2013. Growth is again expected to be driven by the tight reservoir formation plays, but an increase in Federal Gulf of Mexico production is also expected as new projects come on-stream. A further advance of 9% is anticipated by the EIA in 2015, which would take crude production to 9.29mmb/d. This would be the highest crude oil production since 1972. The all-time high for US crude production was 9.6mmb/d in 1970. Total oil and liquids supply in 2015 would be 12.97mmb/d.

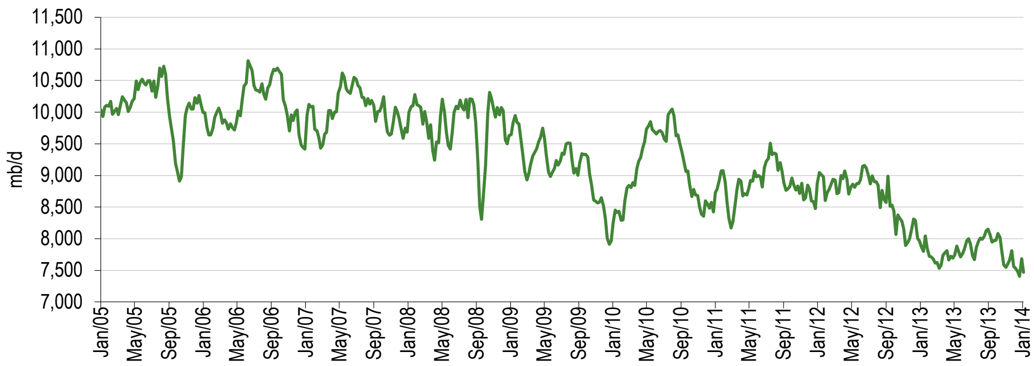
The EIA has recently provided its new long-term forecasts for US crude oil production. Reflecting the strength of the underlying trend in 2013, these have been substantially uplifted compared with the previous annual survey a year ago. The EIA is now looking for crude production to continue rising strongly through 2016 when it is expected to reach 9.54mmb/d, up 27% on the 2013 long-term forecast and very close to the 1970 record. Over the following three years the upward trend is forecast to continue but at a considerably slower pace than of late. In 2019 the EIA is looking for a production peak of 9.61mmb/d, of which about half will be contributed by tight formations. Total oil supply, including NGLs and renewable, in 2019 would be 14.6mmb/d according to the EIA. On the EIA's scenario crude production will dip through 2025 but would still be 9mmb/d in that year. Interestingly, the EIA has tight reservoir production rising until 2021 when it would be 4.80mmb/d. The EIA forecasts call for US crude production in 2040 of about 7.5mmb/d, a level that would not have been considered believable until very recently.

Arguably there is a particularly high level of uncertainty surrounding long-term US production forecasts presently. The key issue surrounds well performance in shale zones and specifically high rates of depletion post initial production. Given this feature, it could become increasingly difficult to maintain momentum as the number of drilling opportunities in existing shale plays diminishes. There is, of course, the possibility that new plays will be discovered, but whether there are any in existence as prolific as the Bakken and Eagle Ford is an open question. On a positive note in the case of the Bakken petroleum system, the deeper Three Forks formation is now beginning to be successfully tapped. According to Bakken pioneer Continental Resources, the Bakken petroleum system including the Three Forks has the potential to double production rates from about 1mmb/d currently to 2mmb/d in the coming years. Significantly, Continental has reassessed its estimate of recoverable Bakken system reserves of late from 24bnboe (20bnbbl oil 4bnboe gas) to 32bnboe, assuming a 3.5% recovery rate (45bnboe at a 5% recovery rate). As Continental suggests, this would indeed make the Bakken one of the most significant discoveries of the past 40 years globally.

Maintaining production momentum will be crucially dependent on further technological advances in extracting oil economically from very impermeable rock formations. Oil, note, is less abundant than gas and due to its molecular structure flows through rocks less readily than gas. We are therefore probably not looking at a replication of the gas boom in the US. Nevertheless, highly significant shale oil opportunities in all likelihood remain in existing and still to be discovered plays.

**Crude imports:** US crude oil imports continue to trend down, driven by rising US domestic production. Taking the four weeks to 10 January 2014 crude imports averaged 7.41mmb/d, down 5.3% from a year earlier. For 2013 as a whole, crude imports averaged 7.61mmb/d, which was 0.78mmb/d or 10% under 2012 and the lowest annual total since 1997.

**Exhibit 4: US crude oil imports**



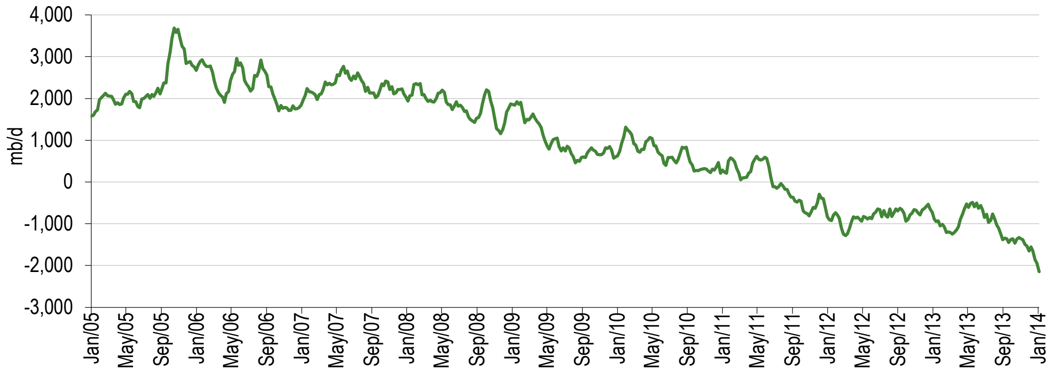

Source: Source: EIA. Note: Data relate to four-week averages.

Compared with the record high of 10.09mmb/d in 2005, imports in 2013 were down by 2.48mmb/d. The EIA is forecasting further falls in crude imports in 2014 and 2015 of 0.90 and 0.74mmb/d respectively. Forecast imports in 2015 of 5.98mmb/d would be the lowest since 1985.

**Net product trade balance: The swing from net imports to exports continues apace**

The drop in crude oil imports only tells part the story in terms of what has been a sharp narrowing in the overall petroleum (crude and refined products) net balance in recent years. Imports of refined product have fallen from peak levels while exports have surged. Through the 10 months to October 2013, product imports averaged 2.12mmb/d, slightly higher than the previous year and 1.6mmb/d below the mid-2000s peak. Possibly even more surprising has been the surge in product exports. In 2013 there was an increase of about 10% to 3.4mmb/d. Compared with the lows of the early 2000s, exports in 2013 were up a hefty 2.4mmb/d. For 2013 as a whole the US had a net export balance on products of about 1.38mmb/d, up 0.31mmb/d on a year earlier. The 2013 net export position compared with peak net imports of about 2.45mmb/d in 2005. There has therefore been a massive swing in the petroleum products trade of 3.8mmb/d over the past few years.

**Exhibit 5: US net product imports**



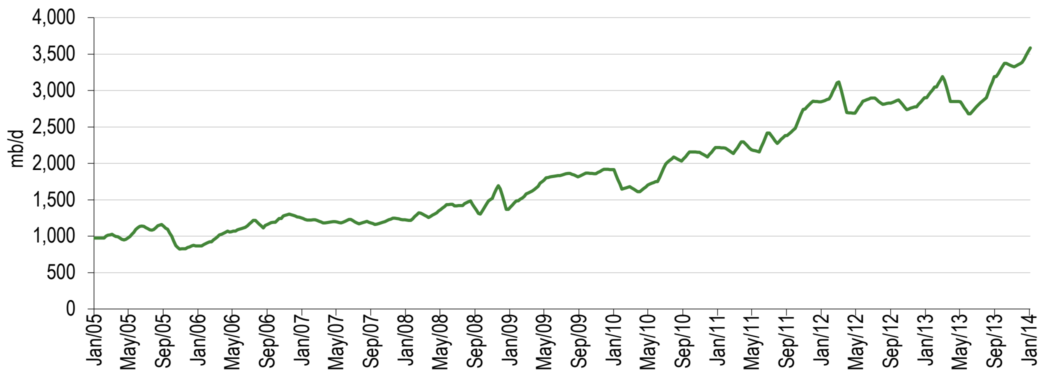

Source: EIA. Note: Data relate to four-week averages; negative recordings are net exports.

The US export boom in petroleum products in recent years has been driven by Gulf Coast refineries. The key markets are Latin America and Europe specifically in the case of diesel. We see the key drivers as follows:

- Internationally competitive US refineries stemming in large part from the availability of both low-cost crude oil feedstock and natural gas. Note the latter is significant both in terms of feedstock and operating expense. Gulf Coast refineries also operate at high utilisation rates internationally and tend to have high middle distillate-yields, the product line showing the highest growth rate.
- Strong underlying demand growth in Latin America, particularly for diesel.
- Major refinery reliability issues in Latin America in recent years.
- Major refinery closures in the Caribbean and Europe have opened up opportunities for competitive US refineries.

We believe the positive trends behind exports are likely to persist for the foreseeable future.

**Exhibit 6: US petroleum product exports**




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

**Texas: Now one of the world's leading petroleum provinces, production rapidly heading for 3mmb/d**

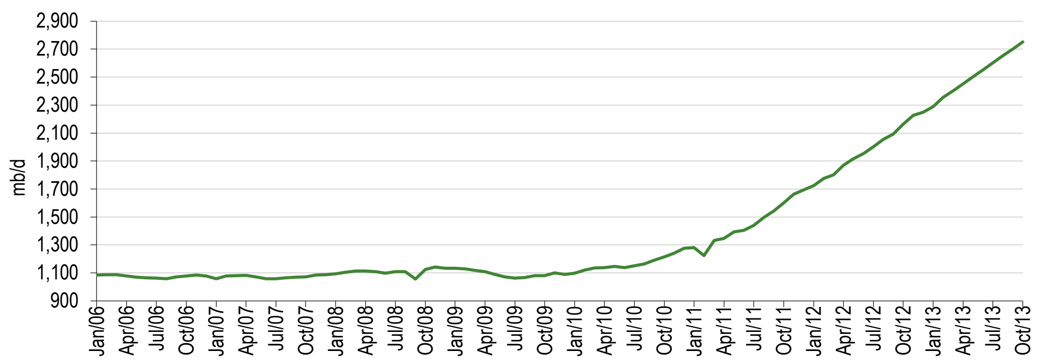
Texas crude oil production continued to increase strongly in 2013. In October, the most recent month for which data is available, the EIA reported production of 2.75mmb/d, 27% higher than a year previously. Cumulatively production through October was up 31% on 2012. From the recent lows in the mid-2000s, production has increased by around 2.6 times, and is now running at the highest level since the early 1980s. The all-time high for Texas oil production was 3.4mmb/d in 1972. For 2013 as a whole, we believe, production may have averaged in the region of 2.6mmb/d, 31% or 0.6mmb/d higher than in 2012. Compared with five years ago production has risen about

1.5mmb/d. Texas is now not only the leading oil producer in the union, but also one of the world's leading petroleum provinces.

The surge in production over the past two or three years has very much been a function of the development of the Eagle Ford shale formation in the Western Gulf Basin in the south-west of the state. Eagle Ford development only began in 2008 and initially was geared to natural gas. As recently as 2010 production was as little as 15,163b/d, but by the third quarter of 2013 appears to have hit around 1mmb/d according to the EIA. At 2013 year end the EIA is forecasting around 1.2mmb/d, which will probably make the Eagle Ford formation the largest single source of oil in the US. For 2013 as a whole Eagle Ford production could be up by perhaps 40% or so based on information supplied by the Texas Railroad Commission earlier in the year. Over the past five years the Eagle Ford has accounted for roughly two-thirds of the gain in Texan production.

The news from the Permian Basin, historically the largest oil producing zone in Texas and home to major tight reservoir stacked plays, has been less bullish of late than for the Eagle Ford. Based on EIA data, the production trend has been flat in recent months at around 1.3mmb/d, of which perhaps 0.3mmb/d relates to New Mexico. The flat trend appears to reflect a plateauing in both the rig count active in the basin and the productivity of new wells. Production in November and December may also have been affected by adverse weather conditions. Nevertheless, due to the carryover effect from rising production in 2012 and gains earlier in the year, Permian Basin production should still rise by approaching 0.1mmb/d in 2013, according to the EIA.

**Exhibit 7: Texas crude oil production**




Source: EIA

**Cline play:** Historically the major sources of oil in the Permian Basin have been the Spraberry, Wolfcamp and Avalon/Bone Spring formations. A new tight Permian play that has recently attracted attention is the Cline Shale or Lower Wolfcamp. Initial drilling results have been positive and according to industry estimates, the Cline could host a stunning 50bnboe. For comparison the Eagle Ford is believed by industry sources to have recoverable reserves of around 10bnboe.

Overall, development potential in Texas therefore would still appear substantial. Over the balance of the decade it would not be surprising to see production in both the Permian Basin and Eagle Ford zones hit 2mmb/d. Bearing in mind significant production in East Texas, this would in turn point to the 1972 Texas record being exceeded.

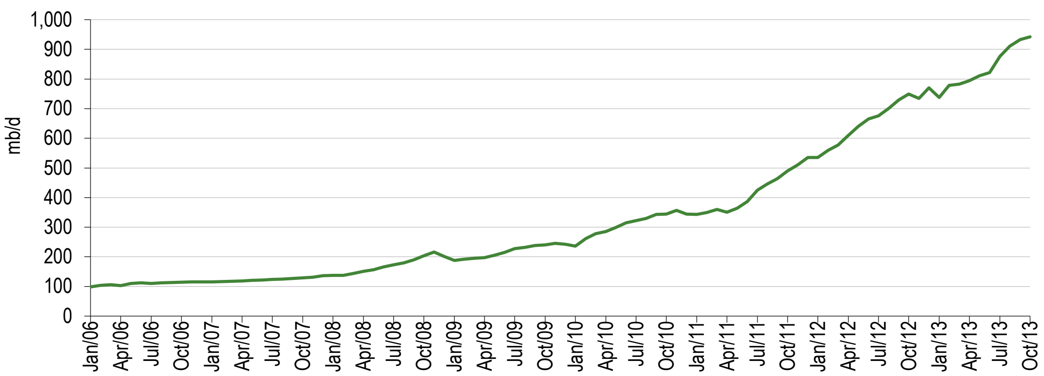
**North Dakota: 2013 was another banner year, production rapidly approaching 1mmb/d**

2013 has been another banner year for North Dakota crude oil production, which has decisively established the state as the second largest producer in the union. Based on North Dakota Department of Mineral Resources (DMR) data, November production came in at 973,280b/d, up 32% on a year earlier. The Bakken petroleum system accounted for 93% of the total. Through the 11 months to November, production averaged 851,972b/d, a gain of 30% from 2012. The month-on-month increase of 27,864b/d or 2.9% in November was well up on a relatively depressed 11,459b/d in October when production was affected by adverse weather conditions. Based on recent trends and statements by the DMR, North Dakota production could be close to 1b/d by 2013 year end. This would imply about 863,000b/d on average for the year, up 30% from 2012 and 2.8 times 2010. The EIA has, in fact, suggested that Bakken production including Montana should exceed 1mmb/d by December 2013. North Dakota's production rate in 2013 has comfortably exceeded the DMR's prognostications at the beginning of the year.

Development and permitting activity in North Dakota has remained buoyant in recent months. During 2013 the wells spudded trended upward from 175 at the beginning of the year to 208 in November. The rig count, however, has continued to fall and at the 11 month stage in 2013 averaged 185 against 200 in 2012. This is pointing to improving drilling productivity and potentially falling costs. Based on EIA data, new well production per rig has also risen decisively in the Bakken over the past two or so years from about 200b/d to 500b/d. Given the positive trends in drilling efficiency and well productivity North Dakota, production will probably exceed 1mmb/d in the first quarter of 2014.

The DMR has indicated in recent months that it believes North Dakota's oil output could hit 1.6mmb/d by mid 2017. The rationale is essentially based on development of the Three Fork formation plus continuing gains in drilling efficiency and well completion technology. Significantly, the DMR tempers its view by suggesting that it is based on an unchanged business and regulatory environment. One of the DMR's major concerns relates to tighter federal regulation on fracking and the associated cost penalties. Other concerns relate to the possibility of higher petroleum industry taxes, and a relative lack of spare refining capacity for light crude in the US.

**Exhibit 8: North Dakota crude oil production**




Source: EIA

**Other tight petroleum reservoir provinces: Strong production growth in Oklahoma, Colorado, NM and Wyoming**

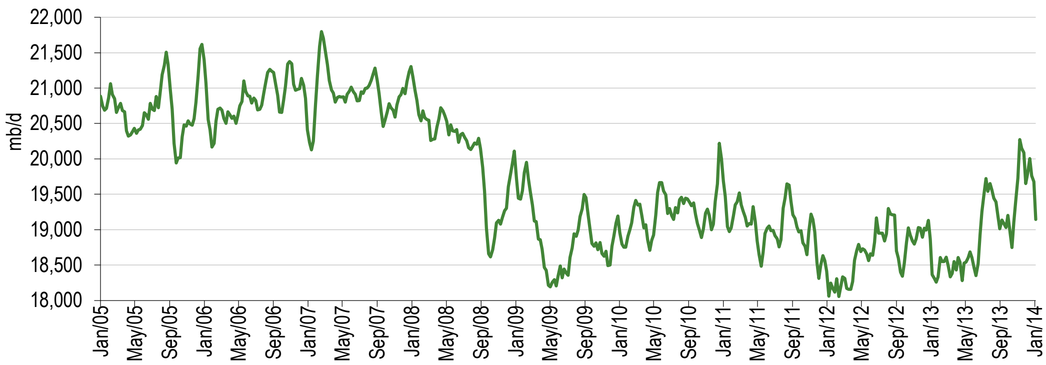
US tight reservoir development activity has been most pronounced in Texas and North Dakota. Several other states mostly on the Great Plains, however, have also experienced a surge in development activity, with the leading examples being Oklahoma (Cana-Woodford shales), Colorado (Niobrara and Codell shales), Wyoming (Niobrara shale) and New Mexico (Permian). All four states have seen a sharp increase in production over the past three to five years. Taking the 10 months to October 2013, crude oil production was up as follows compared with a year previously: Oklahoma 27%, Colorado 29%, New Mexico 16% and Wyoming 11%. Interestingly Colorado output is running either at or close to record levels.

**Domestic demand: The trend firmed noticeably in H213**

**2013:** US petroleum product demand was subdued in early 2013 but in the second half firmed noticeably, thereby partially reversing the downward trend that had been apparent since 2005. Taking the four weeks to 10 January, products supplied (a proxy for demand) came in at

19.1mmb/d, up 4.2% on a year previously according to the EIA. Arguably the most significant development of late has been the recovery in gasoline, the largest product line. Year-on-year movements in the latest four-week period have been as follows: gasoline 2.7%, kerosene 11.9%, distillates 5.4%, fuel oil -16.4%, propane/propylene 5.6% and miscellaneous 4.6%. Reflecting the subdued trend earlier in 2013, full-year petroleum product demand growth was considerably lower than in recent months at 2.1%. Growth by product line was as follows: gasoline 1.3%, kerosene 1.4%, distillates 2.4%, fuel oil -13.5% and miscellaneous including propane/propylene 5.1%. Based on EIA data, demand in 2013 averaged 18.9mmb/d.

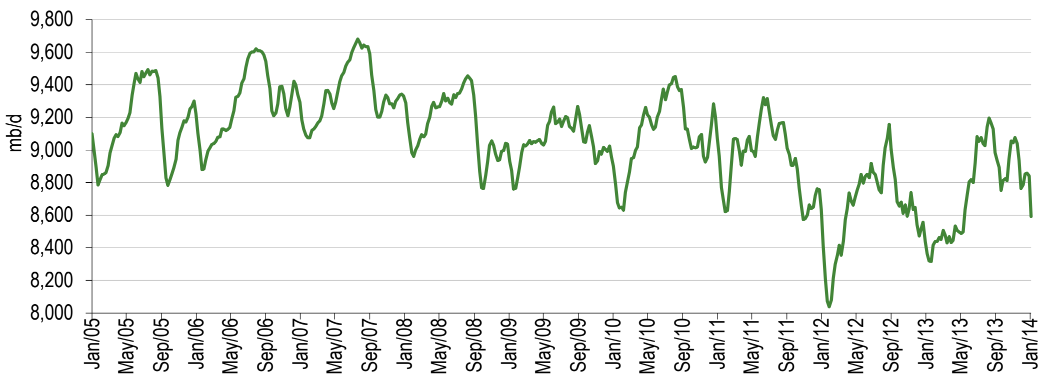
**Exhibit 9: US petroleum product supplied**




Source: EIA

US Petroleum product demand in 2013 comfortably exceeded forecasts made early in the year by the EIA. Significantly 2013 was also the first year with the exception of the post recession year of 2010 to show growth in demand since 2005. Furthermore, demand growth was probably similar to the gain in US GDP. Demand in 2013, however, was still 9.3% below the 2005 all-time peak of 20.8mmb/d. Strengthening underlying demand in the second half of 2013 was driven by a firming US economy in general and falling unemployment in particular. The former factor was especially influential for freight transportation activity, while the latter probably gave a disproportionate boost to gasoline usage, bearing in mind the importance of light vehicles for commuting in the US. We believe the other key factors boosting petroleum demand in 2013 were historically high activity in the agricultural sector, a major user of diesel, and the renaissance in petrochemicals production in the light of the increasing availability of low cost feedstock.

**Exhibit 10: US gasoline supplied**




Source: EIA

**2014/15:** The key question now surrounding US petroleum products demand is how US petroleum product demand will develop in 2014 against the backdrop of a likely significantly stronger economy than in 2013. Interestingly, the EIA is forecasting for 2014 essentially flat petroleum product demand overall, based on GDP growth of 2.4%. The key area of strength remains distillates, with a gain from 2013 of 1.3%. Gasoline consumption in 2014 is forecast by the EIA to decline by 0.1%, while kerosene and miscellaneous demand are expected to be broadly flat. Given recent trends and the apparent buoyancy of the US economy, we suspect that the EIA's near-term demand forecasts may be on the conservative side, particularly in the early months of 2014. For 2015 the EIA's forecasts call for US demand growth of a marginal 0.4%.

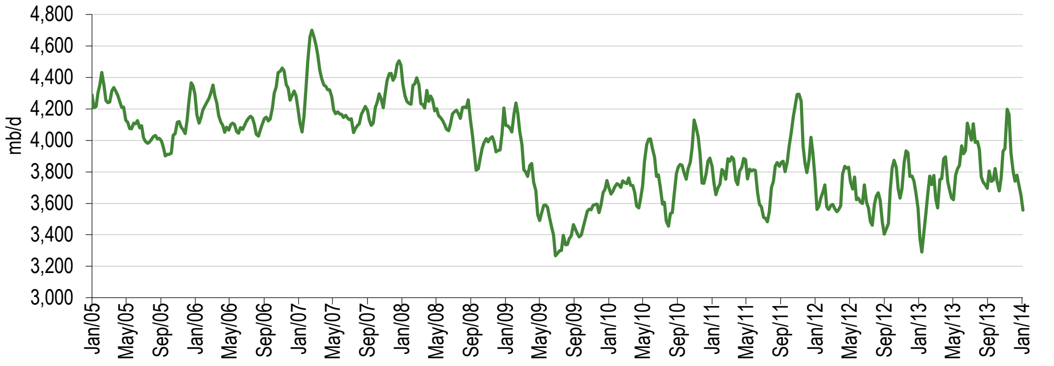
**Exhibit 11: US corporate average vehicle fuel economy**

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| Combined city/highway mpg (US) | 21.0 | 22.4 | 22.6 | 22.4 | 23.6 | 24.0 |

Source: Automotive News/EPA. Note: Data relates to model years and all light vehicles sold in the US. EPA standard for 2025 54.5mpg.

For the medium to long term, we continue to expect US petroleum product demand to trend down moderately, reflecting anticipated major improvements in fuel economy in the light vehicle and aviation sectors and declining fuel oil usage in power generation. Efficiency gains in light vehicles could also be reinforced by lower miles driven per vehicle. Much will depend here on the trend in the real price of gasoline. A key open question currently for the medium to long term is the potential for fuel efficiency gains and the possible substitution of diesel by CNG/LNG in heavy trucks. Regarding the latter point we are sceptical about a major loss of market share for diesel in heavy truck applications given the fuel's vast superiority compared with CNG/LNG in terms of range, ease of refuelling, transportation and storage. There are also important advantages for diesel-fuel trucks in terms of capital cost and payload. Diesel engine manufacturers will, however, be under pressure through legislation from the federal authorities to boost fuel efficiency in the years ahead. Overall, assuming US GDP growth over the next 10 years averaging 2% pa, we would expect US petroleum product demand to decline by about 0.5% pa.

**Exhibit 12: US distillates supplied**




Source: EIA

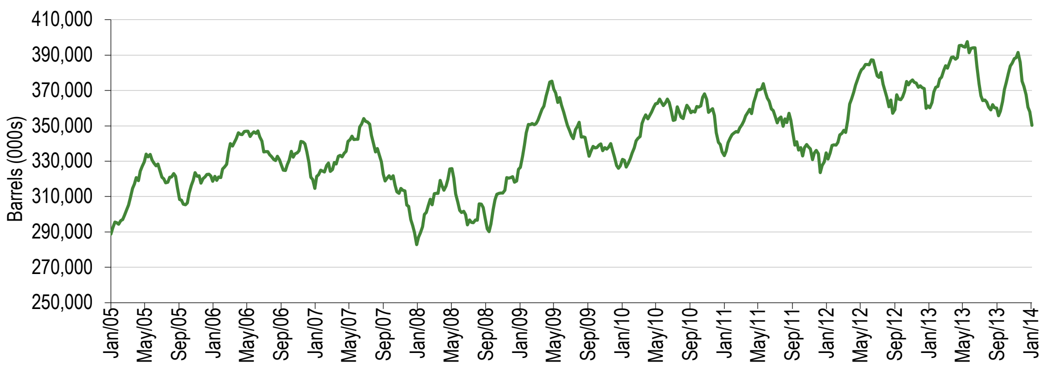
## Inventories

### Crude oil: Sharp fall since late November 2013 but remains high historically

As is usually the case, US commercial crude inventories followed a volatile path in 2013, largely related to seasonal swings in refinery usage. Broadly speaking inventories climbed strongly in the first half to a record high of 397.6mmbbls, dropped sharply in the third quarter, rose strongly in the early part of the fourth quarter and then trended down sharply in the closing five weeks of 2013. Based on EIA data, crude inventories ended 2013 at 360.6mmbbl, more or less even with a year previously and down 30.8mmbbl on the recent 22 November high of 391.4mmbbl. Crude inventories continued to decline through early January 2014 and on 10 January stood at 350.2mmbbl. Despite the decline since 22 November US crude inventories remain at a relatively high level seasonally and only 10mmbbl below a year ago.

EDISON

**Exhibit 13: US crude oil inventory**

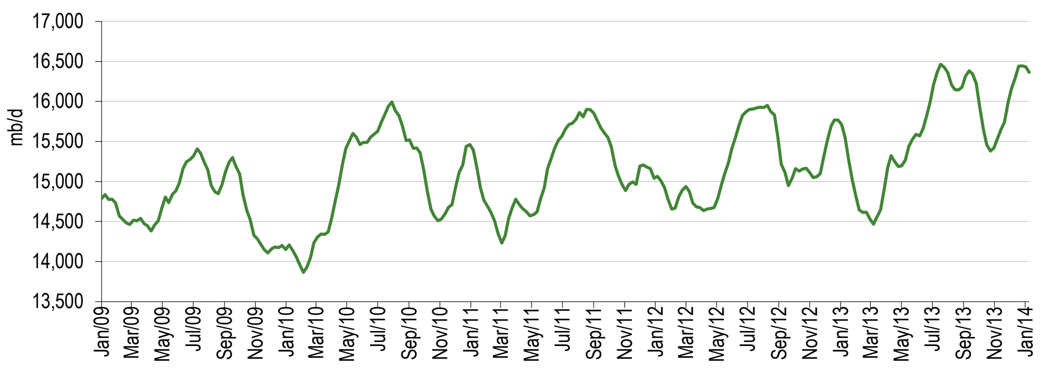



Source: EIA

The fall in inventories in recent weeks essentially reflects a sharp increase in refinery activity from the relatively depressed level of October, when seasonal maintenance and facility upgrading programmes were running at unusually high levels. Refinery runs increased by 0.76mmb/d or 5% between the 18 October 2013 low and 27 December 2013. At the latter date, runs were also 0.81mmb/d above a year earlier. Helping support refinery runs over recent months have been both unprecedentedly buoyant export demand, and the firmer trend domestically. In addition to refinery activity, the recent inventory rundown probably also reflected action to fill the Cushing, Oklahoma to Houston leg of the Keystone XL pipeline. This is scheduled to be opened in late January 2014.

Not surprisingly, inventories on a days' supply basis have fallen in recent weeks, but are not out of line with the levels prevailing historically. On 10 January inventories were equivalent to 21.8 days' supply, down from 23.6 days a year previously. Including the strategic petroleum reserve, inventories on 10 January were 1,046.2mmbbl, equivalent to about 65 days' supply.

**Exhibit 14: US refinery runs**



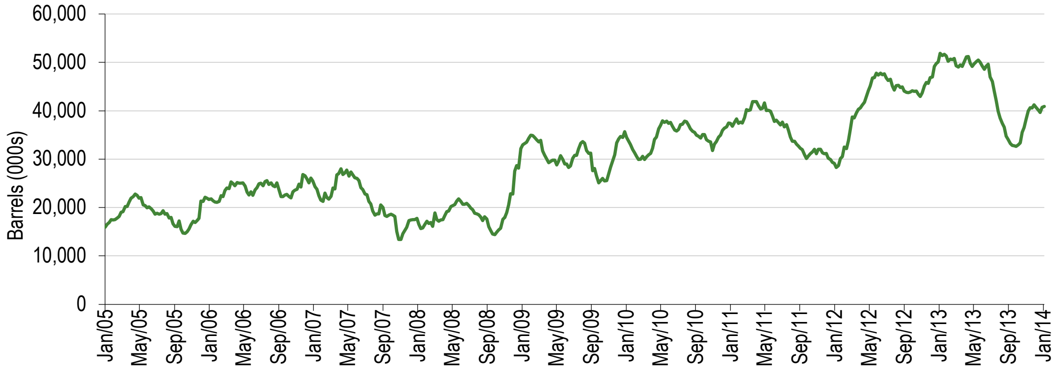

Source: EIA

**Cushing: Holding up at a high level historically**

The trend in crude oil inventories at the Cushing, Oklahoma, tank farm, the delivery point for Nymex crude, has been more robust than that for the US of late. After hitting an early fourth quarter low of 32.6mmbbl, inventories trended higher through early December, reaching a recent high of 41.2mmbbl on 6 December. Subsequently, the trend has eased leaving inventories on 10 January 2014 at 40.9mmbbl. This was 11mmbbl below the record level of a year earlier. Presently Cushing is using 62% of its net working capacity of 65.7mmbbl.

The sharp decline in Cushing's inventories from the record levels of early 2013 reflected a number of upgrades to pipeline infrastructure directing oil to Gulf Coast markets. A key example was phase two of the Seaway Pipeline reversal from Freeport, Texas in early 2013.

**Exhibit 15: Cushing crude oil inventories**



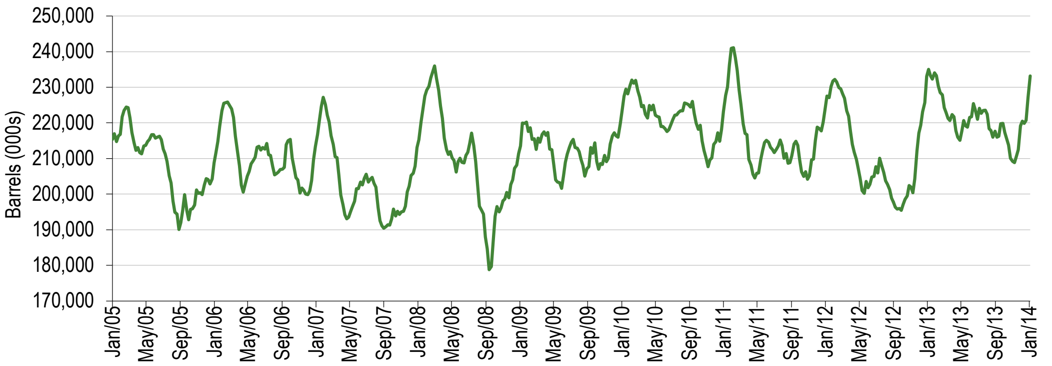

Source: EIA

**Gasoline: Inventories remain seasonally high**

US gasoline inventories were running at seasonally high levels pretty well for the whole of 2013. Based on EIA data, inventories at end year of 220.7mmbbl were 2% down from a year earlier. In early 2014 the trend firmed noticeably leaving inventories on 10 January 2014 at 233.1mmbbl, which was virtually unchanged from the seasonally high level of a year earlier. Gasoline inventories have been supported by historically high refinery runs.

US gasoline inventories on a days' supply basis also look comfortable. At 10 January 2014 inventories were equivalent to 27.1 days' supply, which was down slightly from a year previously but still relatively high based on the experience since 2000.

**Exhibit 16: US gasoline inventories**

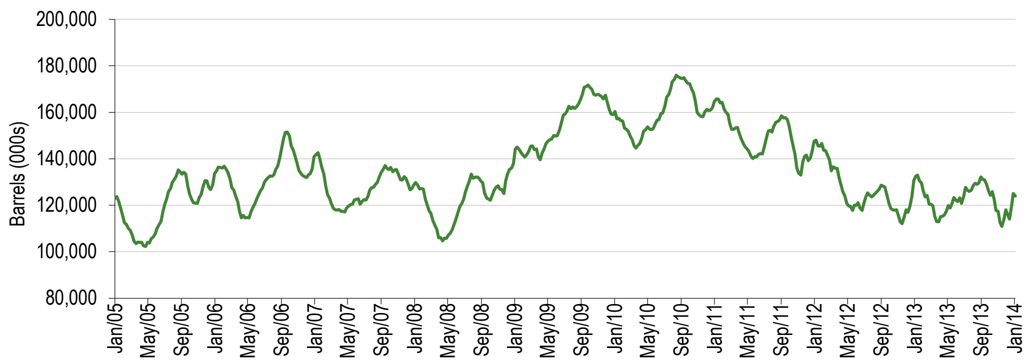



Source: EIA

**Distillates: Inventories remain seasonally low**

Contrasting with gasoline, distillate inventories trended at or below the low end of the seasonal range during 2013. Using EIA data distillate inventories on 27 December were 124.0mmbbl, down 8.4mmbbl on a year earlier and slightly under the low end of the seasonal range. In the latest week inventories were equivalent to 34.8 days' supply, down from 39.2 days a year ago. The days outstanding still remain significantly above the lows of about 22 days plumbed in the early to mid 2000s.

**Exhibit 17: US distillate inventories**



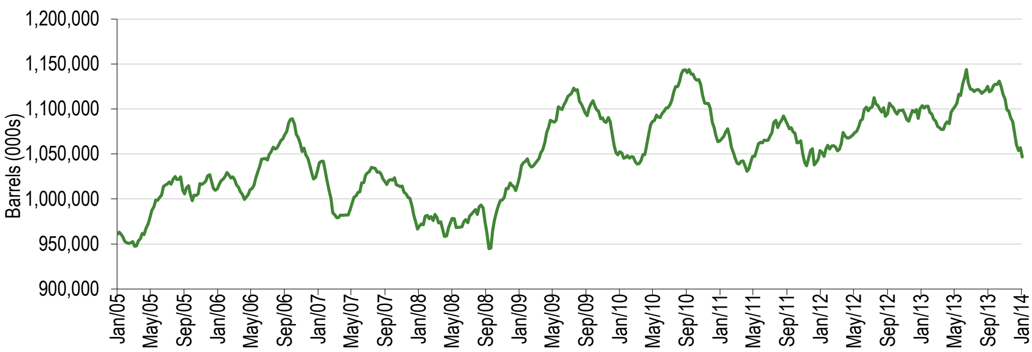

Source: EIA

Declining distillate inventories, both absolutely and in terms of days outstanding, continues to reflect buoyant domestic and particularly export demand. It should be noted that around 40% of exports are distillates and that these tend to have higher crack spreads than domestic sales. There is therefore a natural tendency to emphasise exports over domestic shipments. In the latest four-week period, export shipments at 1.38mmb/d were up 26% on a year previously. We suspect that due to buoyancy of export markets distillate inventories may well remain low relative to recent years for the foreseeable future.

**All petroleum products: Inventories have fallen in recent months but 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 products. Based on EIA data for 10 January, inventories on this definition stood at 1,046.7mmbbl. Looking at the trend in recent months we note that there has been an apparently sharp decline of 97.3mmbbl or 8.5% since the June 2013 peak of 1,144.0mmbbl. It should be noted, however, that the latter was a post 2000 high and in all probability a record. From a post 2000 perspective commercial inventories in total, in fact, remain at a historically high level.

**Exhibit 18: US all petroleum product inventories**




Source: EIA

## Argentina: Shale development poised to commence in earnest

Arguably the most interesting issue now surrounding the shale oil and gas revolution is just how quickly it might spread outside North America. In our view the country that is in pole position in this regard is Argentina. As has been noted by the EIA, the country is supremely well endowed geologically with recoverable resources of 27bnbbl of oil and 802tcf of gas. This puts Argentina in fourth and second position worldwide in terms of shale oil and shale gas respectively. Presently, virtually all the resources have been assigned to the Neuquen Basin in the south-west of the country. The key formation here is the Upper Jurassic/Lower Cretaceous age Vaca Muerta, but there are other shale and tight reservoir targets in the form of the Mid Cretaceous Agrio and the Lower Jurassic Los Molles. Industry studies suggest that the Vaca Muerta is laterally continuous over wide areas and compares favourably with US shale plays on a number of criteria such as formation thickness, porosity, permeability and reservoir pressure. Outside the Neuquen Basin there is another potentially large shale play, called D-129, in the San Jorge Basin in Chubut province in southern Argentina. Neuquen and San Jorge are the major sources of hydrocarbons in the country.

At this juncture, the interesting aspect concerning the Argentine shale oil/gas story is that development is poised to commence in earnest. The key move here was the consummation of the $1.24bn YPF/Chevron joint venture in the third quarter of 2013 and Chevron's transfer of $928m into the project in December. The joint venture is initially planning to drill 130 wells over 18 months as part of a pilot project in the Loma La Lata zone. If successful, this will be followed by the full commercialisation of the Vaca Muerta at Loma, which could result in drilling around 1,500 wells at a cost of $15bn.

The second key move in recent months propelling the shale development story in Argentina has been the federal government's offer of $5bn compensation in government bonds to Repsol for the partial nationalisation of YPF in April 2012. According to Americas Petrogas, one of the leading juniors active in the Neuquen Basin, 10 companies have approached YPF about forming joint ventures to develop the Vaca Muerta since the tentative compensation deal with Repsol. The list includes Anadarko, ConocoPhillips, Southwestern Energy, ENI, BP, Petronas and CNOOC. Significantly, in recent months Wintershall (BASF) and Dow Chemical have both announced major joint ventures with YPF for the development of the Vaca Muerta. Shell is also tripling its investment in the Vaca Muerta zone and Pemex, the Mexican national oil company (and an indirect investor in YPF via Repsol), is said to be interested in undertaking shale oil/gas development in conjunction with YPF.

**What about the political backdrop?**

Many observers have argued that a perceived business unfriendly political environment will stymie major oil and gas development in Argentina. However, we believe that this perception is now obsolete following a surge in the energy import bill over the past few years to over $10bn/year. The federal government desperately wants higher oil and gas production to obviate the outflow of dollars, while the provincial governments are very appreciative of the royalty revenue stemming from such production and the boost to economic growth. It should be noted here that the provincial governments own the mineral rights in Argentina and are an important beneficiary of oil and gas development. In support of its desire for higher production, the federal government has introduced a number of petroleum industry regulatory changes of late. These include:

- Exemptions from export taxes and currency repatriation restrictions subject to certain investment conditions.
- Removal of a 35% import tax on oil and gas drilling rigs.
- Reduced import duties on oil and gas equipment from 35% to 14%.
- Introduction of a more favourable domestic pricing regime for oil and gas. The new regime reflects prices of $70/bbl and $7.50/mmBtu (new projects) for oil and gas respectively. This compares with $42/bbl and $2/mmBtu previously.

With these changes and the unqualified support of federal and provincial governments, the political and regulatory backdrop is now about as favourable for oil and gas development as could reasonably be expected in Argentina. The backdrop certainly contrasts with the hostility to shale development in much of Europe.

It should also be noted that the ruling Peronist FPV faction may well be defeated at the next presidential election scheduled for October 2015 based on political trends in Argentina. Cristina

Fernandez, the current president, is indeed barred constitutionally from running for a third term. Any successor, although probably a Peronist, will in all likelihood be psychologically more disposed to business than Cristina Fernandez.

**The peso plunges** For more than two years Argentina has operated with a dual exchange rate system. The official rate applies to most imports and payments relating to dollar debt. All dollar receipts by exporters and major capital inflows, according to the rules, have to be repatriated and sold for pesos at the official rate. Since its inauguration, the official peso/dollar rate has been subject to a managed downward float. An informally determined unofficial parallel rate also exists and is generally used for private transactions, and particularly purchases of dollars for savings and travel purposes. In addition it is used for some imports. Over the past two or so years a wide spread has opened up between the official and unofficial exchange rates, reflecting a growing lack of confidence in the peso and the management of the Argentine economy. The wide spread can be considered a potential impediment for those concerns, such as foreign oil companies, considering bringing capital into Argentina. There are, however, elegant ways round the problem.

Towards the end of January, the Argentine authorities ceased supporting the peso in an attempt to protect rapidly dwindling currency reserves. As a result, the official rate plunged 17% between end December 2013 and 23 January 2014 to US$1=ARS$7.88 (the average for 2013 was ARS$5.48). This has clearly made the official peso more competitive but the spread remains wide at about ARS$5. A key Argentine policy objective is to narrow the spread substantially. This could be assisted by the recent decision to relax some currency controls. The desire to conserve reserves may also portend a freer float than previously. Overall, we regard the evolving story towards liberalising the Argentine foreign exchange regime as positive for the oil and gas sector, despite the likelihood of near term-inflationary pressures.

**What about the petroleum industry infrastructure?**

Another perceived obstacle to oil and gas development in Argentina is a supposed lack of oilfield services. This we believe is wide of the mark. The country is not a newcomer to oil and gas and has in fact been a producer for about 100 years. The local petroleum industry is well served by oilfield service companies and Argentina has plenty of engineering know-how. Interestingly, Argentina is host to Tenaris, the world's largest producer of seamless tube.

Argentina also has a well developed pipeline, refinery and petrochemicals industry infrastructure. Doubtless this would need expanding if oil and gas production takes off, but this is no different than anywhere else that oil and gas development is being undertaken. Two major intrinsic positives for Argentina, in terms of oil and gas development, are a very low population density in areas such as Neuquen province, and generally flat and semi-arid high-plains terrain in much of the west and south-west of the country. The highway system is more than adequate for transporting heavy machinery, and specifically in the case of Neuquen, there are major sources of water, courtesy of river systems (Colorado, Neuquen and Limay/Rio Negro) originating in the Andes.

**Where are we with production?**

YPF has the largest land position (about 40% of 30,000km$^2$) in the Vaca Muerta shale zone and has so far conducted the bulk of the development activity. According to the company, 30 wells were drilled in the third quarter of 2013 using 19 rigs. During the period unconventional production was still modest at 12,934boe/d but is gathering momentum. In a recent presentation, YPF has indicated potential production from its Loma Campana joint venture with Chevron of 50,000b/d of oil and 3mmcm/d of gas. The time span has not been identified but we would think around two years. It should be noted that Loma Campana constitutes only 3.3% of YPF's Vaca Muerta acreage. Assuming that the Neuquen Basin is as prospective as studies and initial development activity suggest, we could conceivably be looking at a production surge similar to the Bakken and Eagle Ford over the balance of the decade. Based on well rates of 100b/d, or similar to the average for the Bakken, production from the 1,500 wells for the full commercialisation of Loma Campana would be 150,000b/d plus associated gas. Development projects elsewhere in the Vaca Muerta could conceivably provide sizeable upside.

## Brent and WTI 2013 price trends in retrospect: First down year for Brent since 2009

There were three dominant themes for international oil prices in 2013. These were supply disruptions both actual and speculated upon, the growing availability of light crude in the Atlantic Basin stemming from rising US production, and weak demand in Europe. The issue of supply disruptions, actual and prospective, was influential for Brent in February and August with peaks of $119.3/bbl and $118/bbl respectively. The catalyst for the former reflected the backwash of the Aim-Amenas terrorist attack in Algeria in addition to general bullishness in financial markets at the beginning of 2013. The latter reflected growing supply concerns related to Libya and the threat of western military intervention in Syria. The sharp dips in Brent of about 19% between February and mid-April and of 13% between end August and early November reflected the dissipation of supply concerns in the Middle East and North Africa and a switch in market focus to the underlying bearish influences. Helping propel Brent lower between end August and early November were the accord relating to putting Syria’s chemical weapons stockpile under international control, and the initial agreement between the western powers and Iran over Iran’s nuclear programme.

**Exhibit 19: WTI 2009-15 quarterly prices ($/bbl)**

| | 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 | 95.0 | 95.0 | 93.0 | 93.0 | 94.0 |
| 2015e | 92.0 | 90.0 | 88.0 | 88.0 | 89.5 |

Source: Bloomberg, Edison Investment Research

**Exhibit 20: Brent 2009-15 quarterly prices ($/bbl)**

| | 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 | 108.5 | 108.6 |
| 2014e | 105.0 | 104.0 | 102.0 | 101.0 | 103.0 |
| 2015e | 99.0 | 99.0 | 97.0 | 97.0 | 98.0 |

Source: Bloomberg, Edison Investment Research

At the April and November lows in 2013, Brent plumbed $96.8/bbl and $103.1/bbl respectively. Supply concerns related primarily to Libya again resurfaced in December 2013, but these proved short-lived. Brent finished 2013 at $110.8/bbl, down 0.9% on a year earlier. For 2013 as a whole Brent averaged $108.6/bbl, which was 3% below a year previously and close to our most recent forecast. Brent also had its first down year in 2013 since 2009. The easing of Libyan supply concerns combined with further evidence of buoyant US supplies led to a significant softening in Brent to $106/bbl in mid-January 2014. This was close to a six-month low.

One of the key features of 2013 in terms of the WTI to Brent relationship was the out-performance of the former by the latter. This broke the pattern of the prior three or so years. After trending broadly flat through the first six months of 2013 at an average $94/bbl, WTI surged over the following two and a half months, peaking at a 30-month high in early September of $110.5/bbl. Compared with the 17 April 2013 low of $86.7/bbl, WTI at this time was up 27%. The surge was driven by both a sharp increase in refinery activity following the completion of maintenance programmes and a marked decrease in inventories at the NYMEX pricing point of Cushing. The latter stemmed in part from higher refining activity, and in part a re-engineering and expansion of pipeline capacity that re-directed burgeoning Mid-Continent and Permian Basin crude production directly to the refining centres of the Gulf Coast.

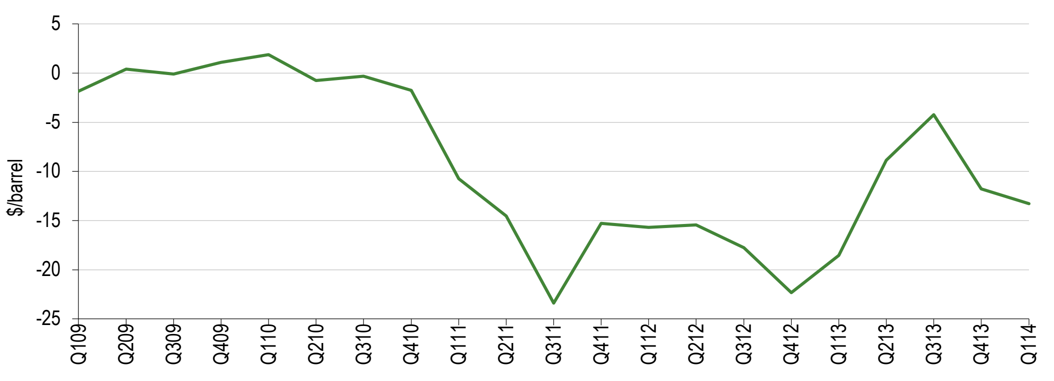
The WTI gains between July and early September were rapidly unwound over the following two and a half months or so as US inventories, including those at Cushing, rebounded. Towards end November WTI was trading at $92.7/bbl, around a five-month low. During December, WTI firmed, driven principally by a sharp decline in US inventories and distinct signs of firming domestic product demand and bullish trends in financial markets. WTI hit a December high of $100.3/bbl on 27 December and finished the year at $98.4/bbl, up a marginal 0.5% on a year previously. For 2013 as a whole, WTI averaged $98.0/bbl, 4% higher than a year earlier. It was also the highest average level for a full year since 2008. In common with Brent, WTI slipped noticeably in the early days of 2014, driven principally by a bearish interpretation of the EIA's end December status report, which showed further gains in crude output and a sharp increase in gasoline and distillates inventory. By mid January WTI was back down to $92/bbl, around a seven-month low.

## Light crude spreads

**WTI-Brent: WTI discount widened again in Q413**

The WTI discount to Brent, which had been consistently apparent since the second quarter of 2010, was all but erased by mid July 2013, reflecting the strength of the former relative to the latter during the first and second quarters. Subsequently, the discount widened and for the third quarter as a whole averaged $4.2/bbl, the narrowest WTI-Brent quarterly spread since the first quarter of 2011. The WTI discount continued to widen through late November, hitting a recent high of $19.0/bbl on 27 November. Rising US inventories combined with the continuing upward trend in US production were the key factors. During December the discount narrowed somewhat in response to a renewed US inventory run-off, albeit from a historically high level and relatively buoyant domestic demand. The spread narrowed to $13.4/bbl in December and averaged $10.9/bbl for the fourth quarter. On average the WTI discount to Brent in 2013 was $10.6/bbl, well down from the $17.8/bbl of 2012. In early 2014 WTI traded at a discount to Brent of about $13/bbl.

**Exhibit 21: WTI-Brent spread**




Source: Bloomberg

Conceptually it might be thought that the WTI-Brent spread should be equivalent to the costs of shipping from Cushing to the Gulf Coast. Presently, for uncommitted shipments by pipeline this is about $4/bbl. Shipment by rail and truck, however, results in considerably greater costs at perhaps $10/bbl for the former and $20/bbl for the latter. Bearing in mind that truck shipments are relatively small, a blended cost might be in the region of $7/bbl, which leaves a significant variance compared with the early January 2014 WTI discount. In practice, however, given the surge in availability of light oil along the Gulf Coast over the past year or two, Brent priced crudes are no longer relevant as a benchmark for assessing WTI. Import prices of light crudes now have to match the new benchmark, Light Louisiana Sweet (LLS), a Gulf-sourced grade that is similar in specification to WTI and Brent. This situation is likely to prevail for as long as exports of US crude are largely embargoed. If we look at the WTI-LLS spread currently, WTI is trading at a discount of $6-7/bbl, which is broadly in line with our blended inland transportation/handling cost estimate.

The above would suggest that a WTI discount to Brent of $10/bbl plus could conceivably be considered 'normal'. The precise discount will tend to vary with the following:

- Light oil supply-demand conditions internationally.
- 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 and the Permian and Western Gulf Basins.

Brent is clearly more exposed to international influences than the inland US WTI benchmark. Importantly, the requirement for light crude in the Midwest has recently been reduced following the completion of the upgrade of BP's giant 415,000b/d Whiting, Indiana, refinery. This will now operate using 80% heavy feedstock rather than 20% previously. Interestingly, Gulf refiners, such as Valero, are now looking to increase capacity using light crude feedstock after having spent a number of years emphasising the use of heavy feedstock.

Further pipeline capacity expansion is scheduled to come on-stream in 2014/15 between the Mid-Continent and the prolific oil producing zones of Texas and the Gulf Coast. According to Valero Energy, the increase could be 1.23mmb/d, with the key projects being the southern legs of Keystone XL and Seaway from Cushing and the Bridge Tex, Plains Cactus, SXL Permian Express and SXL WTG from the Permian Basin. The extra pipeline capacity should make a major contribution to shipping the prospective increase in crude oil production from the Permian Basin and Mid-Continent and may facilitate a reduction in transportation costs and firming in WTI in due course. The supply surplus may, however, be simply shifted from Cushing to the Gulf Coast.

Based on the above factors, we would expect WTI to typically trade at a discount of $6-12/bbl over the next two years. In the event of geo-political turmoil or major outages outside North America, the discount could conceivably be significantly greater on occasion as has been the case over the past two or three years. By contrast, an extended period of tranquillity geopolitically, possibly combined with a definitive accord between the western powers and Iran over the latter's nuclear programme, could result in the spread being towards the lower end of the above range. For 2014 we look for the quarterly WTI-Brent spread to be as follows: Q1 $10.0, Q2 $9.0, Q3 $9.0, Q4 $8.0. The average for the year is a discount of $9.0/bbl, up from $6.5/bbl forecast previously, reflecting the wider than expected carryover spread from 2013. For 2015 we are looking for a WTI discount averaging $8.5/bbl.

**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 Midland has sold at a small discount of a dollar or less to WTI Cushing. Over the fourth quarter of 2013 the Midland discount was somewhat greater, averaging $3.1/bbl. We believe this is likely to have reflected minor transportation bottlenecks. In early January the Midland discount was slightly wider than normal at $1.75/bbl.

**Bakken-WTI: Bakken discount narrowed sharply in late 2013**

Bakken grade (Clearbrook Minnesota hub) oil has a broadly similar specification to WTI. With the exception of Tesoro's 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 region with a price point of Clearbrook, Minnesota. Bakken oil was initially mainly shipped either to Midwest and mountain state refineries or to Cushing. Over the past year or two, new markets have opened up on the eastern and western seaboards, as rail logistics have been upgraded. This has enabled Bakken producers to capture high-priced markets leveraged to Brent and Alaska North Slope (ANS).

Historically, Bakken oil has tended to sell at a discount of several dollars a barrel to WTI, although the picture has 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 interruptions. Recently, a third factor has intervened in the form of the swings in the WTI discount to Brent. This has gained in importance given the large volumes of oil now being shipped to the seaboards.

The key point here is that, based on Valero Energy data, the cost of railing oil from the Bakken to the Pacific Northwest is about $9/bbl and to the eastern seaboard $14-17/bbl. We would estimate that shipments to Los Angeles might be around $15/bbl. To maintain competitiveness in seaboard markets, Bakken therefore needs to sell at a discount to Brent or ANS at least equivalent to transport costs. The problem comes for Bakken producers when the WTI-Brent spread narrows sharply as happened in the third quarter of 2013. To maintain competitiveness in such circumstances the Bakken-WTI spread will need to widen, which indeed happened with a slight lag late in the third and early in the fourth quarters. At the low point in November the Bakken discount to WTI was $16/bbl, resulting in an absolute price of a depressed $78/bbl. Subsequently, the Bakken discount has narrowed sharply in tandem with the widening WTI-Brent spread. By early 2014 Bakken was trading at roughly a $2/bbl discount to WTI. If we take this plus the $13/bbl WTI discount to Brent it is close to transportation costs to the eastern and western seaboards.

**Exhibit 22: Bakken-WTI spread**


Source: Bloomberg

Based on our forecast of a $9/bbl WTI-Brent discount in 2014, Bakken would need to trade at a similar discount to WTI to be competitive in eastern and western seaboard markets other than in the Pacific Northwest. To cover transport costs to this destination, the discount to WTI would need to be about $2/bbl assuming that Brent and ANS trade at approximate parity. Based on our 2014 WTI forecast of $94.0/bbl, the implied Bakken price would therefore be $85-86/bbl.

In the event of wide Bakken discounts to WTI of $15/bbl plus being required to sustain seaboard business for any length of time we would expect Bakken producers to refocus sales on inland markets based on WTI prices. Given that about 80% of Bakken oil is being shipped by rail, a switch in emphasis to domestic markets can be undertaken relatively easily. Additions to refining capacity in the Midwest and ideally North Dakota would probably enhance Bakken economics. Tesoro has recently completed a modest expansion of its Mandan refinery while a joint venture between MDU Resources and Calumet Specialty Products is constructing a relatively small 20,000b/d topping facility at Dickinson western North Dakota. With the surge in economic activity related to the oil boom, the demand for diesel in North Dakota has increased strongly in recent years.

**Bakken economics:** Not surprisingly perhaps, Lynn Helms, the head of the North Dakota Department of Mineral Resources, indicated in December 2013 that oil drilling in parts of the state had become uneconomic at the depressed Bakken prices prevailing a month or so earlier. However, Lynn Helms has also suggested that at $75/bbl it is still "extremely economic" to drill in the four core counties of Dunn, McKenzie, Mountrail and Williams (the four counties account for about 86% of North Dakota output) plus Stark county and most of Divide county.

**Exhibit 23: Indicative Bakken economics**

| | $/bbl |
|---|---|
| Gross realisations | 75 |
| Royalties | -14 |
| Net realisations | 61 |
| Lifting and site operating costs | -12 |
| Severance costs | -4 |
| G&A | -5 |
| Transport to Clearbrook, Minnesota | -5 |
| EBITDA | 35 |
| Drilling/completion costs | -15 |
| EBIT | 20 |

Assumptions:
- Royalty rate 18.5%
- Severance rate 5%
- Drilling/completion costs $8m/well, estimated ultimate recovery: 550,000bbl
- No allowance for natural gas

Source: Edison and industry presentations

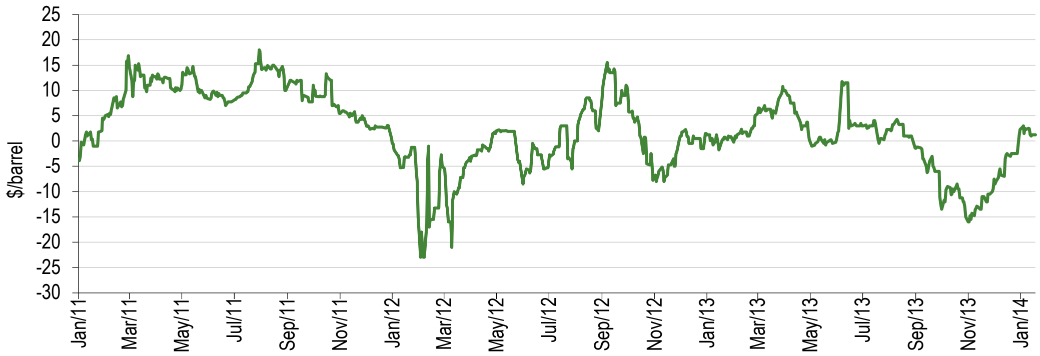
Based on a cursory estimate of Bakken costs, we would concur in part with Helms' view. For a typical Bakken well, fully accounted costs (before the cost of capital) could be around $55/bbl, which would imply a profit contribution of $20/bbl assuming realisations of $75/bbl ex-Clearbrook. Excluding realisations, the critical element in the equation relates to the estimated ultimate recovery (EUR). We have assumed a typical Bakken sweet spot EUR of 550,000bbl and drilling/completion costs of $8m/well. If the EUR turns out to be 300,000bbl, fully accounted costs per barrel would rise to $67/bbl, which would eliminate a large part of the contribution at a price of $75/bbl. In reality we can probably say that Bakken economics start to become debatable at $75/bbl and marginal below $70/bbl. Much, of course, will depend on the prospectivity of the zone being drilled. The previous conclusions only refer to drilling new wells. Given the large element of fixed and sunk costs, historical wells will be economic on a cash flow basis at prices considerably below $75/bbl.

**Syncrude-WTI: Swing to a modest Syncrude premium in early 2014**

The spread between syncrude, the synthetic sweet crude produced from the Athabasca oil sands, and WTI has shown a similar trajectory to Bakken of late. Syncrude was actually trading at a premium to WTI for much of the first eight months of 2013 but this was followed by a swing to a discount late in the third quarter. Like Bakken, the syncrude discount hit bottom in early November at $16/bbl (Edmonton Alberta). Over the balance of 2013 there was a narrowing and by end year approximate parity with WTI had been achieved. In early 2014 Syncrude was trading at a premium of $3/bbl to WTI.

Given significant refining capacity in Alberta and Saskatchewan and also pipeline capacity to the Midwest and Ontario we would normally expect syncrude to trade close to WTI. Refinery outages will, of course, tend to result in sharp price dips. In the event of sustained discounts of comfortably over $10/bbl we would expect to see shipments increased to the Gulf Coast and particularly the eastern and western seaboards where higher priced Brent or ANS markets are available. According to Valero, rail costs from Alberta are $9-12/bbl to eastern Canada and $13-15/bbl to Los Angeles.

**Exhibit 24: Syncrude-WTI spread**

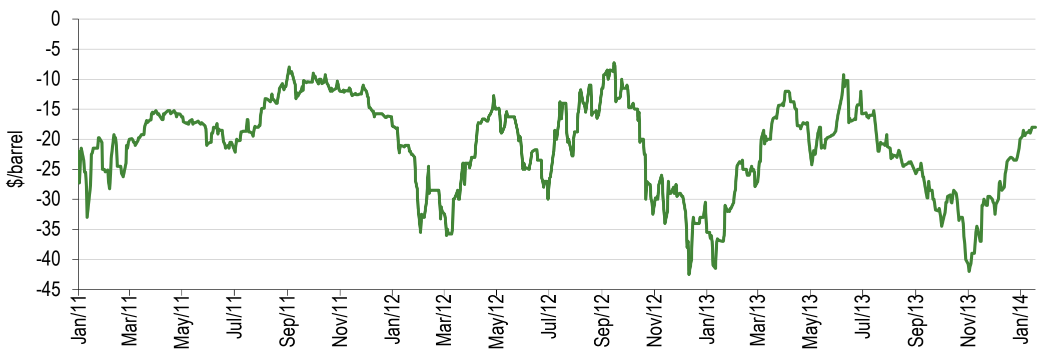



Source: Bloomberg

**Western Canada Select (WCS)-WTI spread: Sharply narrower WCS discount in late 2013**

WCS (Hardisty, Alberta hub) is a heavy-sour Albertan blended grade using conventional and oil sands bitumen feedstock with an API of 20.5°. Reflecting the specification and sourcing, WCS typically sells at a substantial discount to WTI and is one of the world's lowest priced crude grades. Between June and early November 2013 the WCS discount to WTI widened substantially from $9/bbl to $42/bbl, a historically broad spread. The latter implied a price of a mere $42.0/bbl. The issues were rapidly rising oil sands production, pipeline constraints and refinery outages such as at Citgo's Lemont Illinois facility. Over the following two months the WCS discount narrowed sharply and in mid-January 2014 was $18/bbl, implying a price of about $75/bbl. For 2013 as a whole WCS averaged $73.6/bbl, slightly up on the $71.8/bbl of a year previously.

**Exhibit 25: WCS-WTI spread**




Source: Bloomberg

A key factor behind the narrowing spread since November 2013 has probably been the bringing fully on-stream of BP's upgraded Whiting refinery near Chicago in early December. Whiting will now operate using approximately 80% heavy feedstock sourced from Alberta rather than 20% previously. As a result, heavy feedstock demand will increase by about 0.35mmb/d.

**Economics:** Depressed WCS prices have raised the issue of oil sands economics. According to the government and industry-funded Canadian Energy Research Institute (CERI), the fully accounted supply cost, including a 10% return on investment, for a new oil sands mine in 2013 was $68/bbl of bitumen. At a WCS price of $73.6/bbl there would therefore have been some modest headroom with regard to supply costs. Using the alternative in-situ steam-based production route economics would be significantly more favourable, given estimated supply costs of $48/bbl of bitumen, according to CERI. A key issue surrounding oil sands bitumen production concerns high transportation costs reflecting high viscosity, the need to add dilutants and long distances to export markets. CERI estimates the costs of blending and transportation at approaching $30/bbl. We believe this is based on delivery to Cushing Oklahoma.

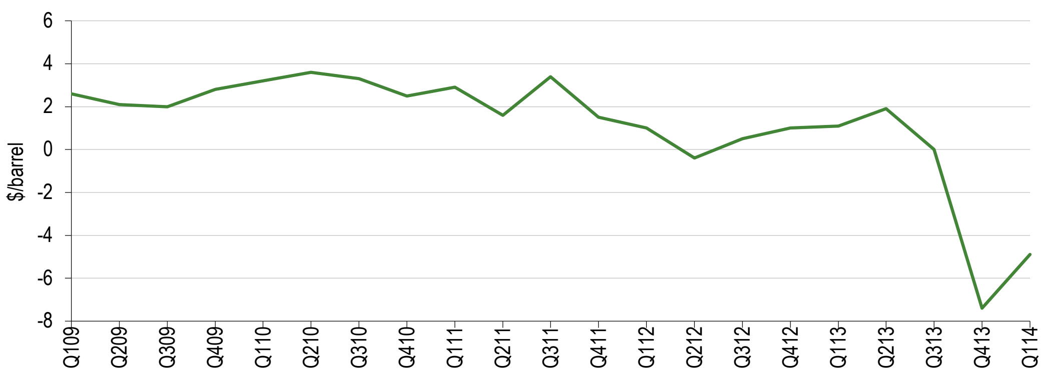
The above would indicate that at a WCS price ex-Hardisty of $75/bbl, new oil sands projects, assuming the in-situ production route, are potentially comfortably profitable. Clearly, mining based projects are more marginal. Given high transportation costs, the issue for Albertan heavy oil then becomes one of competitiveness with other North American heavy grades such as Mexico-sourced Maya. As of early January 2014 Maya was selling on the Gulf Coast at about $86/bbl. Backing out transport costs of $30/bbl would imply a netback of $56/bbl, which would modestly exceed fully accounted costs assuming the in-situ production route. Based on the mining assumption, there would be a fully accounted loss. Netbacks would probably be significantly higher based on the shorter supply lines involved with Midwestern refineries such as Whiting. A better alternative  from an economics perspective, would be if heavy oil refining were undertaken in Alberta and the refined product output exported.

**LLS-Brent: LLS swings to a discount**

During 2013 the relationship between LLS, the Gulf Coast light crude benchmark, and Brent changed fundamentally. Historically, LLS had traded at a $2/bbl or so premium to Brent. The premium began to unwind in 2012, and as 2013 progressed the tendency became more apparent. During late August, LLS swung decisively from premium to discount. After trading at a discount of $3.3/bbl in September, LLS subsequently traded on average at around $7.5/bbl under Brent over the balance of 2013. By mid-January 2014, however, the LLS discount had narrowed to $2-3/bbl.

The swing from an LLS premium to discount was not surprising, although the magnitude has arguably been greater than expected. Driving the swing has been the influx of light oil on the Gulf Coast stemming from the upgrading of pipeline and rail links from the Mid-Continent and prolific Texas oil producing zones in the Permian and Western Gulf Basins (Eagle Ford). Effectively, the supply surplus that previously existed at Cushing has now to some extent shifted to the Gulf Coast. Given anticipated production trends in the Mid-Continent and Texas along with the expansion of the pipeline infrastructure, we would expect LLS to remain at a highly significant structural discount to Brent for the foreseeable future.

**Exhibit 26: LLS-Brent spread**




Source: Bloomberg

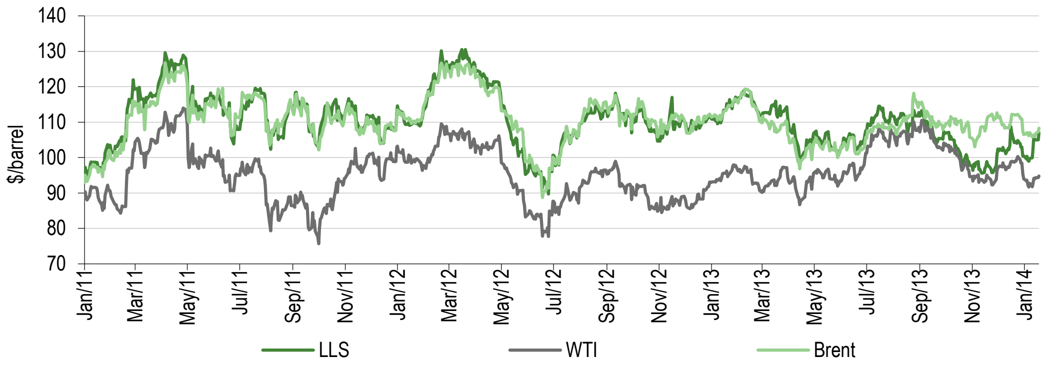
**Brent-Dubai spread: In line with the historical range**

Dubai Fateh is a Gulf-sourced light but relatively sour crude popular with Far Eastern refineries. In recent months Dubai has traded broadly within the historical range of a $2-3/bbl discount to Brent. Taking 2013 as a whole the average Dubai discount was $2.92/bbl, somewhat up from $2.35/bbl a year previously. During 2013 the Dubai discount was at its low in April and December at just over $1/bbl, reflecting tight supplies of sour grades and r declining availability at times of Kirkuk (northern Iraq) and Urals grade crude. In 2013 supplies of Kirkuk crude were constrained by terrorist activity, while Russian domestic refinery needs have limited the availability of Urals on world markets in recent months. Assuming a resumption of Iran's exports in the wake of a comprehensive agreement with the west over its nuclear programme, the Dubai discount could widen significantly.

**Tapis-Dubai spread: Normal relationship**

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 price relationships. Typically, Tapis trades at a significant premium of $7-10/bbl, reflecting its premium specification. Overall, 2013 was an unexceptional year for the Tapis-Dubai spread. Other than in March and April when supplies of sour grades were tight, the Tapis premium during the course of the year was pretty much within the historical range. For 2013 as a whole the average Tapis premium was $9.3/bbl. In early January 2014 Tapis was trading at a somewhat higher premium to Dubai of $11/bbl. We continue to believe that in due course, with the growing availability of light crudes in the Atlantic basin, the Tapis premium to sour grades could be vulnerable.

**Exhibit 27: Recent trends in WTI, LLS and Brent**




Source: Bloomberg

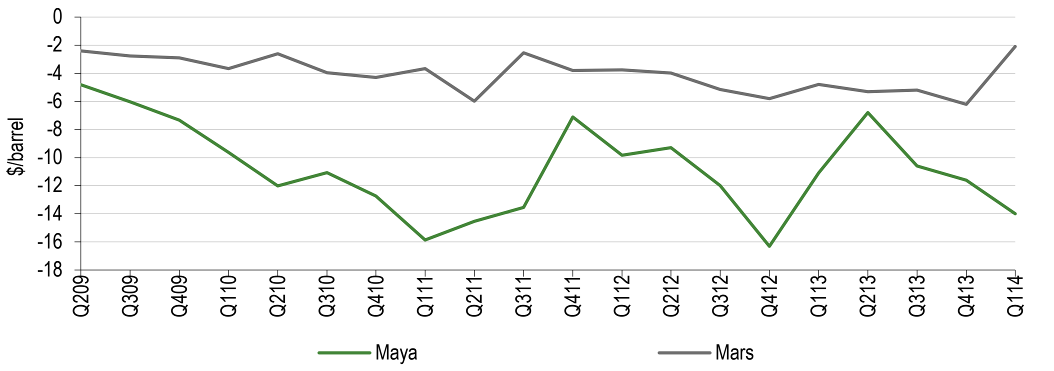
## US Gulf heavy crude spreads: Mars discount narrows

**LLS-Mars:** Mars is a medium-sour grade sourced from the Gulf of Mexico that normally trades at a discount of $2-6/bbl to LLS. The Mars discount was fairly stable in 2013 towards the top end of the historical range. For the year the discount averaged $5.4/bbl, up from $4.7/bbl in 2012. Significantly, the Mars discount narrowed sharply between December 2013 and early January 2014 from $4.9/bbl to $2.1/bbl. This reflected strong downward pressure on LLS stemming from the emergence of a sizeable surplus of light crude along the Gulf Coast. The likely continuation of the light crude supply build up could portend a long-term narrowing of the Mars discount to LLS.

**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 $5-12/bbl. The Maya discount was generally towards the high end of this range in 2013 and for the year averaged $10.0/bbl, down from $11.9/bbl in 2012. Surprisingly perhaps, in view of the apparently buoyant demand for heavy feedstock and the growing light crude surplus along the Gulf Coast, the Maya discount remained broadly unchanged between December 2013 and early January 2014 at a historically high $14/bbl.

**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/bbl. In late 2012 and early 2013, however, the WTS discount was an unprecedented $15-20/bbl due to severe logistical constraints in the Permian Basin and an outage at a major user of the grade, the Phillips 66 Sweeny refinery in Texas. By March 2013, however, the WTS-WTI spread had more or less returned to normal. This was followed by an extended period in the second and third quarters when the WTS discount was marginal at a few cents a barrel, and on occasion there was even a small premium for the first time in 25 years. In the fourth quarter of 2013 the WTS discount widened markedly to $4.1/bbl on average but by early January 2014 had returned to a more normal $2.7/bbl. Buoyant demand for heavy feedstock along the Gulf Coast amid an abundance of light oil might suggest a long-term erosion of the historic WTS discount.

**Exhibit 28: US medium and heavy discounts**




Source: Bloomberg, Edison Investment Research

## Forward curves: WTI in mild contango at the front end, Brent in backwardation

There have been no major changes in the forward curves for Brent and WTI since our last report at the end of September 2013. Brent remains in backwardation (near-term prices higher than for forward dates) for all dates through 2020. The curve starts at $106.3/bbl for March 2014 deliveries and then dips fairly evenly over the next eight years, hitting $87.4/bbl in March 2020. Brent's backwardation theoretically continues to reflect perceptions of supply tightness, reflecting uncertainty concerning North Sea production and geopolitical issues, of which the most significant is Libya. Given the emergence of surplus light crude in the Atlantic basin due to the sharp drop in US imports along the Gulf Coast, the continuation of the pronounced Brent backwardation is arguably a little surprising.

WTI's mild contango at the front end of the curve is pointing to a comfortable light crude supply position in the US Mid-Continent plus just possibly hedging activity by US oil companies. Regarding the latter point, the key issue is that a significant amount of shale oil development activity in the US is being financed with debt. To help mitigate risk, banks and other lenders are effectively forcing oil companies to lock in futures prices through derivative instruments, which in turn is tending to boost supply and reduce prices in the out years. In the event of a bout of weakness in WTI, hedging could intensify with highly detrimental consequences for prospective realisations and shale oil project economics. The WTI curve presently commences in February 2014 at $93.8/bbl. After peaking at $94.0/bbl in March it then goes into marked backwardation through late 2017, hitting $77.4/bbl by year end. Subsequently the curve levels off and terminates at $74.9/bbl in December 2022. The implied WTI discounts to Brent based on the forward curves are $12.3/bbl in March 2014, $14.6/bbl in December 2017 and $12/bbl in March 2020.

## Refinery crack spreads: GC cracks narrow in 2013 but remain high historically

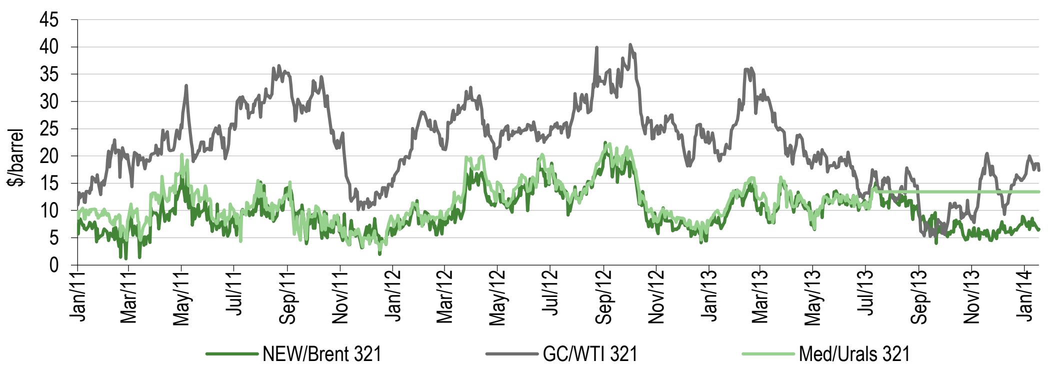
US refinery crack spreads based on cost-advantaged domestic light crude slipped between 2012 and 2013, but remained at historically high levels. Taking, for example, the US Gulf Coast/WTI 321 spread (the margin before refining costs on converting three barrels of WTI into two barrels of gasoline and one of diesel) there was a narrowing between the two years from $26.3/bbl to $17.6/bbl on average. For perspective, the long-term average is about $10/bbl. During 2013 the

USG/WTI 321 spread ranged from a high of a very profitable $36/bbl in February to a marginal $5/bbl in September. We believe the average spread for 2013 constituted a comfortably profitable level for the typical Gulf Coast refinery processing WTI.

At 16 January 2014 the USGC/WTI 321 crack spread was close to the 2013 average at $17.4/bbl. Note, crack spreads based on Bakken feedstock and Midwest product prices would have been significantly higher at times in 2013 than suggested by the USGC/WTI 321 crack. This mainly reflects the Bakken discount. We believe operating Midwest and Mid-continent refineries using domestic light grade feedstock has evolved into a very profitable business in recent years.

The 2012 crack spread was exceptionally high historically and was the envy of refiners in most other parts of the world. It reflected a sharp divergence during the course of the year between falling feedstock costs and rising product prices, with the latter stemming in large part from refinery closures along the eastern seaboard and in the Caribbean. The favourable circumstances, however, unwound in 2013, with product prices falling and feedstock costs increasing. Abstracting from unplanned outages, we believe a major change in the USGC/WTI 321 crack spread is unlikely in 2014.

**Exhibit 29: Recent trends in crack spreads**




Source: Bloomberg

## Crude oil price outlook: Brent unchanged for 2014, WTI downgraded

The fundamentals are pointing to a potential slide in international oil prices in 2014 and conceivably 2015. The key bearish influences include the buoyant production trend outside OPEC (mainly North America), likely moderate global demand growth, a comfortable inventory position and the potential for at least two key OPEC members, Iraq and Libya, to boost output. The upshot is that barring major unplanned outages, non-OPEC controlled output, including OPEC NGLs, should comfortably exceed world demand growth in 2014 and in all probability 2015. As always perhaps, OPEC production is the key wildcard, but as yet seems to be trending not too far away from the 'call' or global demand after allowing for non-OPEC supply. From an OPEC perspective, the major wildcards relate to Iran, Libya and Saudi Arabia. Clearly, an early resumption of Libyan exports to the semblance of normality, and an accord between the world's major powers and Iran over its nuclear programme, would add massively to bearish influences. Interestingly, Saudi Arabia has intimated that this time around, it would not necessarily accommodate increases in other OPEC members' output by significantly reducing its own.

In the light of the above we continue to expect Brent to trend down in 2014. Our average price forecast for Brent is unchanged at $103/bbl. The quarterly scenario for 2014 is as follows: Q1 $105.0, Q2 $104.0, Q3 $102.0, Q4 $101.0. Reflecting the anticipated supply build-up, we expect the downward trend to continue in 2015, with Brent averaging $98.0/bbl. We have not allowed anything in these forecasts for early resumptions of large-scale Libyan or Iranian exports. Either event could easily result in a significantly weaker trend in Brent than postulated. As noted in our previous review last October, estimating the potential impact of an end of the sanctions regime on Iran is a particularly fraught exercise. We believe, however, that a downward adjustment in Brent of 5% to possibly 10% might not be surprising, compared with where prices would otherwise have been. Following a deal with the west over Iran's nuclear programme, we would expect Iran to move quickly to boost exports. This may not initially be equivalent to the approximately 1mmb/d lost to sanctions, but in all likelihood will be significant at a few hundred thousand barrels a day. The odds of an accord with Iran over the next months are probably no better than 50:50.

Burgeoning US supplies have exerted downward pressure on WTI in early January 2014. Indeed, the pressure has been a little greater than we had been expecting. Our underlying scenario for WTI is unchanged for 2014 in that we expect the price to trend down, driven by rapidly growing US production. Given the weaker trend in WTI in recent weeks than previously expected plus the robustness of supply, we are modestly downgrading our 2014 WTI average year forecast from $96.5/bbl to $94.0/bbl. The quarterly profile is as follows: Q1 $95.0, Q2 $95.0, Q3 $93.0, Q4 $93.0. We expect the likely continuing supply build-up in the US to maintain downward pressure on WTI in 2015. For 2015 we forecast a WTI average price of $89.5/bbl.

A downward trend in WTI in 2014/15 has now probably become the consensus position. For contrarians this raises the question as to what might lead to the opposite outcome. We see three key possibilities:

- There is a possibility of a considerably more robust economy than currently expected. This is certainly a possibility, although as we have noted, technological developments are tending to blunt the impact of the economy on oil demand.
- The regulatory framework could be tightened regarding fracking, water usage, transportation or other factors. The spate of derailments and crashes involving oil tanker trains in recent months in the US and Canada is ominous in this regard. One distinct possibility is that the existing tank car fleet might have to be replaced over time by a more robust design.
- The production trend could prove to be less robust than presently expected, due perhaps to higher than anticipated rates of depletion. The type curves (empirically derived production curves) in the major plays appear to be very well established, but inevitably there is scope for deviation and a run of disappointing data.

**What is the downside risk on WTI?** In the absence of a major recession along the lines of the late 2000s, the downside risk to WTI on a sustained basis from around $90/bbl is probably modest. The reason is relatively high development costs in the US shale and tight reservoir plays plus sometimes significant transport costs. Our earlier analysis for Bakken economics suggested that development could start becoming problematic at $70-75/bbl. Allowing for the Bakken discount, this could imply WTI in the high $70s to low $80s/bbl. In our view, WTI much below this zone on a sustained basis would probably lead to sharply reduced drilling activity, with consequent negative implications for the production trend. Any levelling off in production would probably lead to a rapid rebound in WTI.

**Exhibit 30: Brent and WTI price scenarios**

| $/bbl | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014e | 2015e |
|---|---|---|---|---|---|---|---|---|---|---|---|
| WTI | 56.6 | 66.1 | 72.2 | 99.8 | 62.0 | 79.5 | 94.9 | 94.2 | 98.0 | 94.0 | 89.5 |
| Brent | 54.5 | 65.4 | 72.7 | 97.7 | 62.0 | 79.7 | 110.0 | 112.0 | 108.6 | 103.0 | 98.0 |

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

# US natural gas market

## Production and net imports

**Recent trends: Flat to slightly higher**

**Production:** US natural gas production has continued to trend broadly flat sequentially in recent months. This continues the pattern apparent since late 2011. Based on EIA data, marketed production in the 10 months to October 2013 was 21.24tcf, up a marginal 0.9% on a year previously. Taking the two most recent months, September and October, there were year-on-year gains of 0.4% and 1.2% respectively. Production has continued to be supported by rapid development activity in the prolific Marcellus shale zone of Pennsylvania and West Virginia, plus by-product gas output in new oil producing provinces such as the Bakken and Eagle Ford. Major gains in these areas have offset falling production in several of the traditionally large producing regions including the Gulf of Mexico, Louisiana and Wyoming. In these three states production has been trending down for some time. Looking at October in isolation, gross natural gas withdrawals have shown year-on-year movements as follows: Texas (traditionally the largest producer) 1.1%, Louisiana (traditionally the second largest producer) -26.4%, Oklahoma 5.6%, Federal Offshore -19.0%, Wyoming -0.7% and 'other' 15.8%. Note 'other' includes the non-traditional large-scale producing states such as Pennsylvania, West Virginia and North Dakota. Significantly, other now accounts for roughly a third of US production and makes a larger contribution than Texas.

The Marcellus formation in Pennsylvania and West Virginia is one of the largest natural gas discoveries of recent years, not only in North America but also globally. According to the EIA, up to 141tcf of reserves may be recoverable. The development of the formation has been very rapid with production increasing from a modest 142bcf in 2009 to an estimated 3.54tcf in 2013, based on EIA data. Compared with 2012, production in 2013 looks like being up by about 50%. The strong momentum reflects growing output per new well and infrastructural developments that have enabled previously shut-in wells to be brought on-stream. In 2013 the Marcellus has probably accounted for about 15% of total US gas output. A rise in the weighting to 18% has been referred to by the EIA. The deeper Utica shale formation in Pennsylvania and Ohio is rapidly attracting development interest and could add significantly to gas production in addition to NGLs over the next two or three years.

**Net imports:** US net imports have fallen sharply over the past few years. Through the 10 months to October 2013 net imports were 1.04tcf, down 22% from a year earlier. Compared with 2011, net imports were 38% lower. Presently, virtually all gross pipeline imports of 2.29tcf in the 10 months to October 2013 were from Canada, with shipments from Mexico having all but ceased due to plentiful US supplies. Modest volumes of LNG are still imported principally from Trinidad. Reflecting strong domestic demand and production constraints, Mexico has provided US producers with a significant and rapidly growing market for pipeline gas. In the 10 months to October 2013 exports to Mexico were up 9% from a year earlier at 563bcf (around 2bcf/day). For the same period exports to Canada were roughly unchanged at 774bcf.

Export shipments to Mexico are currently well within cross border pipeline capacity of about 3.4bcf/d. A substantial 2bcf/d increase in capacity is presently underway linking the Agua Dulce hub in southern Texas with northern Mexico. Start-up for the new link is scheduled for late 2014.

**Outlook: Modest production gains in 2014/15**

Adverse weather conditions have probably depressed US natural gas production in the final weeks of 2013 and very early 2014. This is unlikely to be sustained. Generally over the next year or two we continue to expect the production trend to be subdued due to the lagged impact of lacklustre drilling activity. As we have noted, however, considerable quantities of gas are being produced as a by-product of shale oil development and further benefits in terms of marketed production should be obtained from infrastructural expansion, particularly in the Marcellus and Bakken. Rising new well productivity also looks like remaining a positive in the near term at least, reflecting continuing advances in completion techniques. Based on EIA data, US marketed production in 2013 was probably a new record of about 25.6tcf, up 1.3% on a year previously. For 2014 and 2015 the EIA is looking for gains in output of 2.1% and 1.3% to 26.2tcf and 26.5tcf respectively.

In its recent long-term outlook the EIA forecasts a trend increase in US natural gas production through 2040. This contrasts with crude oil, which begins to slip post 2020. The EIA's forecast for US natural gas production growth between 2012 and 2040 is 1.6% pa. This is the fastest gain of any energy source other than renewables excluding biomass and hydro. The bullish forecast trend reflects, of course, the massive resource base that has been identified in recent years and which is probably sufficient for considerably over 100 years' consumption. Significantly, the EIA's latest cumulative 2012-40 production forecast is 11% higher than a year ago. The forecast assumes a trend increase in the Henry Hub benchmark price of 3.7% pa in real terms (2012 prices).

The EIA is also anticipating a swing in the US trade balance in gas from net imports of perhaps 1.26tcf or 3.44bcf/d in 2013 to a net export position of perhaps 300bcf by 2018. The drivers here are trend growth in pipeline exports to Mexico and the commencement of LNG exports probably in 2016. Importantly, the forecast of a net trade surplus on gas in 2018 is two years earlier than anticipated by the EIA in its 2013 long-term outlook. Medium-term pipeline exports to Mexico are expected to be driven by a powerful cocktail involving the following:

- Strong (5% pa) underlying domestic consumption growth.
- Constrained domestic availability.
- Mexico's desire to reduce expensive LNG imports. Presently its pipeline imports cost about 25% of imported LNG.
- Mexico's plans to sharply reduce the fuel oil burn rate in power generation for both economic and environmental reasons.

## Consumption

**Recent trends: Weak Q313 trend but probable weather-related uptick in closing weeks of the year**

In the three months to October 2013 the US domestic consumption trend was weak seasonally. For the period there was a drop of 3% compared with a year earlier. In isolation October's consumption was, however, off 2% year-on-year. Cumulatively through October 2013 US natural gas consumption was down 0.3% on a year earlier. The major area of weakness in 2013 was power generation, the largest market segment for natural gas. Taking the year to date, power generation consumption fell 8% driven by a decline in the power station burn rate from 31.3% to 27.7%. The decline in the burn rate reflects a well documented loss of competitiveness in natural gas compared to coal in power generation applications. Broadly speaking, between 2012 and 2013 power generation fuel prices (per million Btu) rose about 33% for natural gas while falling 1% or so for coal. It should be noted that the power station gas burn rate in 2012 was historically high, while that for coal was low.

Looking at the other key natural gas markets, consumption was also weak in the three months to October 2013 with the exception of industrial. On a year-on-year basis for this period, consumption was down 2.6% and 0.7% in residential and commercial markets respectively, while in industrial it was up 1.1%. The picture is, however, considerably stronger in the year to October, with year-on-year gains of 19% for residential, 12.5% for commercial and 2.4% for industrial.

**Outlook: Near-term power station burn-rate constraint**

US natural gas consumption was boosted seasonally for both power generation and space heating applications in the closing weeks of 2013 and in early 2014 by extreme cold in the key markets of the Midwest and Northeast. Within this context, the EIA's forecast of a 2.1% gain in consumption in 2013 to 26tcf looks plausible despite the broadly flat showing in the 10 months to October.

In 2014 consumption should receive a significant boost from a strengthening economy. However, this could be partially offset by a further decline in the power station burn rate, if natural gas prices strengthen relative to coal, which indeed is the EIA's forecast. The EIA's forecast for the natural gas power station burn rate in 2014 is 26.8%, significantly down from the 27.5% estimated for 2013. This combined with the assumption of more normal weather conditions also results in a drop in usage in the residential and commercial segments. A further gain in industrial usage provides a partial offset, but not by enough to prevent US natural gas consumption dropping by 2.2% to 25.4tcf according to the EIA. A combination of economic growth and an anticipated upturn in the natural gas burn rate related to tightening regulation on emissions could see a recovery in consumption in 2015. The EIA is currently forecasting a gain of 2.1% to 25.9tcf.

In the medium to long term, natural gas consumption in the US should be supported by two key positives. The first relates to the likelihood of plentiful supplies of relatively low cost supplies of the commodity courtesy of the massive resources/reserves position. This is currently giving a major boost to activity in petrochemicals along with energy intensive sectors such as metals and petroleum refining. Secondly, in an era where regulation is tightening on power generation emissions, relatively low cost and low emitting natural gas should be at a considerable competitive advantage to alternative fuels and sources of energy. It should also be noted that natural gas fuelled power stations tend to have relatively low capital costs and can be installed quickly compared with the alternatives. The EIA is forecasting growth in US natural gas consumption of 0.8% pa between 2012 and 2040.

## Inventories: Recent weather-related sharp fall

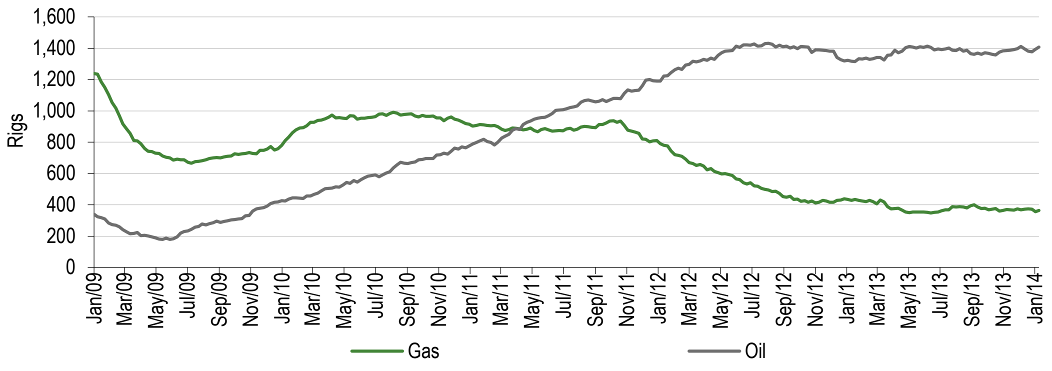
US natural gas inventories entered the withdrawal period in October 2013 broadly in line with the seasonal average position. Since then, the decline in inventories has been seasonally strong, reflecting colder-than-normal conditions especially in December and early January 2014. Based on EIA data for the week ended 10 January 2014 inventories stood at 2,530bcf, down 287bcf on the prior week, and 659bcf or 21% on a year earlier. The decline in the most recent week was a record and reflected recent extreme cold in the Midwest and Northeast. Compared with the five-year average for the time of year, inventories on 10 January were 443bcf or 15% lower. The decline in inventories of late has taken them below the five-year range for the time of year. In the absence of an extended period of mild weather, US inventories are now likely to enter the next injection season at the end of March at the lowest level in more than five years. At the end of March 2014 the EIA is forecasting inventories of 1,541bcf, down 182bcf or 11% on a year earlier. In the light of recent developments there may be downside risk to this forecast.

## Drilling activity: Plateauing

US drilling activity has remained on a broadly flat trend in recent months. Based on Baker Hughes data, the rotary rig count overall on 27 December 2013 was 1,757. This was down 0.3% on a year previously and 13% from the 4 November 2011 high of 2,026. The strong upward trend in the dedicated oil rig count plateaued in 2013 at a historically high level. At the end of December the US oil rig count stood at 1,382, up 55 or 4% on a year earlier. Compared with the 8 October 2012 all-time high of 1,432, the rig count at end December 2013 was down 3%. The dedicated oil rig count in the US continues to be buoyed by interest in the shale and tight reservoir plays of the Great Plains, Texas and the Mountain States.

The gas-based rig count slumped in 2012 in tune with the price of dry gas but the trend began to level off in 2013. On 27 December 2013 the gas rig count came in at 374, which, although down 13% on the year ago level of 431, was 7% above the 21 June low of 349. Recent gas rig counts of significantly under 400 compare with almost 1,000 in the third quarter of 2010 and over 1,500 in the third quarter of 2008. We believe drilling for dry gas will remain subdued at a low level until gas prices reach at least $4.5/mmBtu and possibly nearer $5/mmBtu on a sustained basis. We believe prices in this range are required to cover long-term marginal development costs.

**Exhibit 30: Baker Hughes US rig count**




Source: Baker Hughes, Bloomberg

**What looks interesting?** Baker Hughes' analysis of the US rig count by basin over the past year reveals some interesting findings as follows:

- The basin with the largest increase in the rig count is the DJ-Niobrara (Denver-Julesburg) in north-east Colorado and south-east Wyoming. Here the rig count was up by 36 to 51. The Niobrara play is at an early stage of development and has been referred to in industry circles as the next Bakken. It has attracted considerable interest from a range of medium to large-scale independents including Anadarko, Bill Barrett, Chesapeake, EOG, Noble, Samson and SM Energy.
- Interest in the Marcellus has possibly waned slightly over the past year given a drop in the rig count by six to 86. The slack, however, has been made good by an increase of the same amount in the newer and liquids-rich Utica play located mainly in Ohio. There are now 38 rigs operating in the Utica, which is arguably one of the most exciting emerging shale plays. Chesapeake is the largest leaseholder in the liquids-rich eastern sector of the Utica. Interestingly, America Energy Utica LLC, the new development vehicle of Aubrey McClendon the founder and former CEO of Chesapeake, raised $1.7bn in October 2013 to drill in the southern zone of the Utica.
- The Permian Basin retains the largest fleet of rigs at 471, up four on a year ago and equivalent to 27% of the US rig fleet at end 2013. The Permian is, of course, a well established petroleum province characterised by a wide variety of different plays. Technological advances have opened up a number of tight reservoir plays such as the Wolfcamp, Spraberry and most recently the Cline.
- The major Oklahoma shale play, the Cana Woodford, appears to remain of interest given the increase in the rig count over the past year from 31 to 36 rigs. A particularly interesting emerging play towards the south of the Cana-Woodford is the liquids-rich SCOOP formation. Bakken pioneer Continental Resources believes that SCOOP has world-class potential reflecting thick and high-quality shale reservoirs. Continental plans to increase the rigs devoted to SCOOP from 12 currently to 18 by mid 2014.
- The rig count in the Williston Basin (Bakken) over the past year has dropped from 193 to 179. The decline reflects a maturing of the Bakken play along with advances in drilling/completion technology and the high repeatability of drilling operations that have led to major advances in productivity.

## Recent price developments and outlook: Broadly unchanged for 2014

**Dry gas:** US natural gas prices trended strongly higher in the closing weeks of 2013 driven by seasonally very cold weather conditions in the key gas consuming regions of the Midwest and Northeast and a consequent major draw on inventories. Taking the Henry Hub, Louisiana benchmark, the spot price rose from a 5 November low of $3.36/mmBtu to a recent peak of $4.52/mmBtu on 23 December. The latter was around a 30-month high. Over the balance of the year the Henry Hub quote slipped to $4.31/mmBtu, up 25% on end 2012. In the early days of 2014 the Henry Hub quote eased to $4.14/mmBtu as milder conditions temporarily took hold along the eastern seaboard. Prices have however exceeded $4.5/mmBtu on occasion during the first three weeks of 2014.

The averages for the fourth quarter and full-year 2013 of $3.84/mmBtu and $3.73/mmBtu respectively were in line with our expectations. Compared with 2012, the average Henry Hub quote in 2013 was up by 36%. It needs to be remembered here that US natural gas prices were running at very depressed levels in the former year from a post 2000 perspective.

**Exhibit 31: 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 | 4.40 | 3.75 | 4.00 | 4.00 | 4.04 |
| 2015e | 4.50 | 3.90 | 4.20 | 4.20 | 4.20 |

Source: Bloomberg and Edison Investment Research

From the perspective of the past five years or so we believe US natural gas prices could trend at high levels during the first quarter of 2014. Temperatures over the balance of January, at least, look like being significantly below average in the Midwest and Northeast according to weather forecasts and, as we have noted, inventories at the beginning of the injection period at the end of March will probably be at their lowest level in five or more years. Given these factors, we have raised our Henry Hub forecast for the first quarter by 10% to $4.40/mmBtu. This would be the highest level for the period since 2010. In the event of a sustained period of extreme weather we believe there is the possibility of a spike in prices above $5/mmBtu.

Over the balance of 2014 we are broadly maintaining our Henry Hub scenario unchanged. A seasonal dip in prices is expected in the second quarter, taking the average quote down to $3.75/mmBtu. The seasonal upturn in electricity consumption related to heavy air conditioner usage is then forecast to lift the Henry Hub quote to $4.00/mmBtu in the third quarter. In the fourth quarter we assume that a gradual tightening in the marketplace combined with the onset of the 2014/15 winter will keep the quote at about this level. On this scenario, the Henry Hub quote averages $4.04/mmBtu, which is marginally up on our previous forecast of $4.01/mmBtu. In the absence of major changes in weather conditions we look for an upward trend in the Henry Hub quote in 2015 taking the average around 5% higher to $4.20/mmBtu. This reflects an assumed moderate tightening in the supply/demand balance.

**Exhibit 32: Henry Hub price trend**


Source: Bloomberg

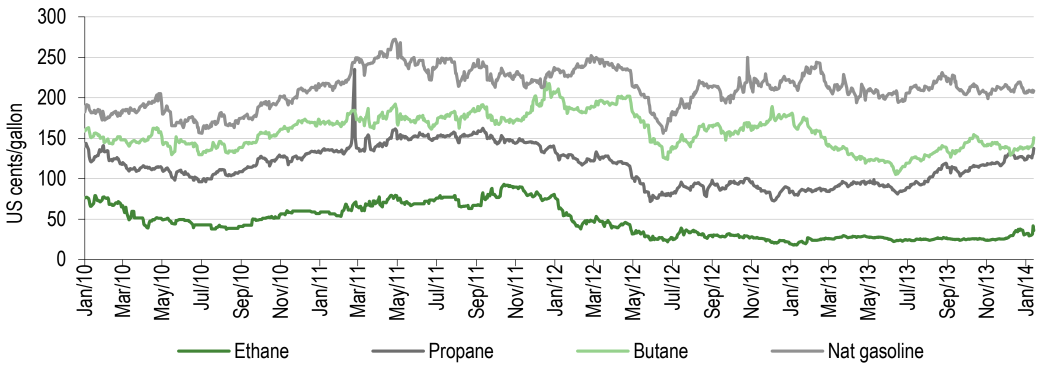
**NGLs:** Natural gas liquids (NGLs) such as ethane (the highest volume NGL), propane, butane and natural gasoline are important petrochemical feedstocks, gasoline-blending agents and fuels. They are valuable by-products of natural gas production. US production of NGLs has grown rapidly in recent years 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 5.3% to 2.54mmb/d, which comfortably outpaced dry gas. Taking the most recent four-week period, ending 10 January 2014, output of 2.70mmb/d was in fact up by a hefty 9.6% on a year earlier.

NGL prices came under heavy pressure in the second half of 2012 reflecting the build-up of supplies and remained at historically depressed levels in early 2013. Generally, however, prices firmed in the second half of 2013. Compared with a year earlier, prices at the end of 2013 were up by 17% and 41% for ethane and propane respectively. However, there were declines of 21% for butane and 4% for natural gasoline on the same basis. Owing to the considerable carryover weakness from 2012 the average price level for ethane fell 35% between 2012 and 2013. Butane on this basis also dropped 14%, but natural gasoline and propane were roughly unchanged.

The strengthening trend in NGL prices in recent months has been despite continuing robust production growth. The explanation reflects strong export demand, especially for propane and a resurgence in US petrochemicals activity. The latter has been very much driven by the growing availability of internationally highly competitive feedstock. Significantly, with ethane below $0.30/gallon or approximately $95/tonne( Mt Belvieu, Texas), US ethylene producers, according to industry reports, can now produce ethylene (the building block for polyethylene and a wide range of other plastics) at cash costs of around $250/tonne. This is more in line with Saudi Arabia, traditionally the world's low-cost producer for the commodity, than in the US or indeed Europe and the Far East. Ethylene in Europe and the Far East is usually produced using a more expensive energy intensive process based oil-derived naphtha feedstock. Presently, ethylene prices in the US are running at about $1,200/tonne Mt Belvieu against $1,480/tonne fob Japan and Korea and $1,350/tonne cif NW Europe. In the fourth quarter of 2013 Mt Belvieu ethylene prices were at times as little as $960/tonne.

We believe US NGL prices could continue to firm during the course of 2014, reflecting a potential tightening marketplace driven by strong export and domestic petrochemical demand. NGL production is also expected to continue trending higher but based on the EIA's forecasts the gain of 2.7% may lag demand growth in our view. We would note, however, that production in early January was already above the EIA's 2014 forecast average of 2.60mmb/d so maybe any firming price trend will be modest.

Exhibit 33: Recent trends in US NGL prices




Source: Bloomberg

**Economics: Semblance of viability for dry gas producers**

The recovery in US natural gas prices in late 2013 and early 2014 has clearly resulted in a meaningful improvement in industry economics. There is now the semblance of viability. Based on an early January 2014 Henry Hub price average of $4.35/mcf, most dry gas producers should now be capable of at least generating a comfortable cash contribution. Our thinking here, based on company reports, is that cash costs could be in the region of $3.17/mcf, split around $1.00 for lifting, $0.22 for severance tax, $0.40 for G&A, $0.75 for pipeline tie and gathering and $0.80 for royalties. This would imply a cash contribution of $1.18/mcf at the above price, which is probably sufficient to cover finding and development costs in many cases. Note this statement of economics is only indicative. In practice economics will vary widely depending on the resource play.

Wet gas producers, of course, continue to enjoy considerably more favourable economics. Particularly in the liquids-rich zones of the Marcellus and Eagle Ford, NGLs and condensates can boost price realisations by more than $3/mcfe to approaching $7.5/mcfe. We believe this implies a very comfortable fully accounted profit after allowing for the operating and capital costs of an integrated NGL plant.

Exhibit 34: Henry Hub natural gas price trend

| | 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 | 4.04 | 4.2 |

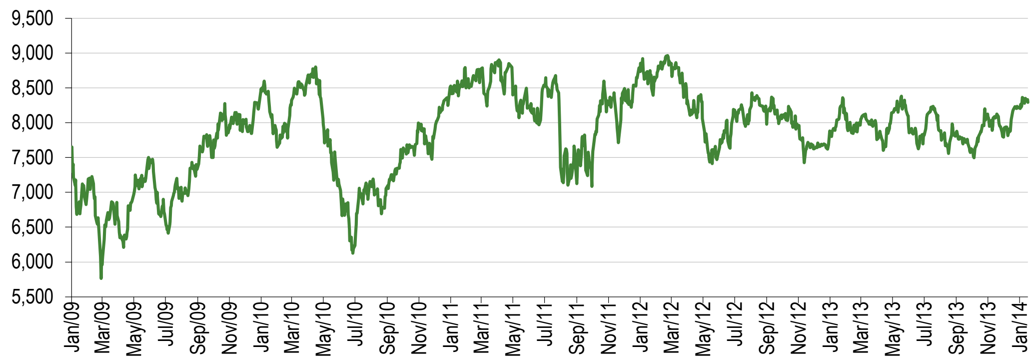
Source: Bloomberg, Edison Investment Research

# Oil and gas sector performance

**UK: FTSE 350 modestly higher, AIM Oil & Gas down again over past year**

The FTSE 350 Oil & Gas Index of large and medium capitalisation UK-based oil and gas stocks (BP, Shell and the BG Group constitute 94% of the index) has trended broadly flat since late 2010, much the same as the Brent price. In so doing, it has significantly underperformed the FTSE 100, which has gained 16% since end 2010. Looking at the 12 months to 15 January 2014 in isolation the FTSE 350 Oil & Gas Index has increased by about 5% but the FTSE 100 has gained by a significantly greater 11.5%. Admittedly, the former index carries a usefully higher yield at 4.2% against 3.6%, but this in no way compensates for the shortfall in performance. Trading on 9x current earnings (12 months to 15 January 2014) and as little as 1.2x book value, the FTSE 350 Oil & Gas Index is valued at a substantial discount to the FTSE 100, where the equivalent multiples are 16.8x and 2x respectively according to Bloomberg data. Statistically the UK oil and gas heavyweights have the characteristics of value plays. The recently announced disappointing performance by Royal Dutch Shell in the fourth quarter of 2013 suggests that depressed valuations may not be entirely without reason from a short-term perspective at least.

**Exhibit 35: FTSE 350 Oil & Gas Index**




Source: Bloomberg

The AIM oil and gas juniors have had another torrid year. After dropping by 4% in 2012 the benchmark AIM Oil & Gas Index fell by a further 10% in the year to 15 January 2014. The Index is now down 44% on the recent February 2011 peak and 51% on the all-time 2006 high. By contrast, the AIM All-Share Index has risen 20% over the past year (a strong showing given that oil and gas stocks have a 17% weighting) and has declined 31% since the all-time high in 2006. The AIM Oil & Gas juniors have therefore significantly underperformed the AIM All-Share Index both in the recent past and from a longer-term perspective. Interestingly, the AIM Oil & Gas Index showed tentative signs of firming in the fourth quarter of 2013 and in early 2014. Between 1 October 2013 and 15 January 2014 there was a gain of 12%, which was in line with the AIM All-Share Index.

The weak performance of the oil and gas juniors reflects a combination of a generally disappointing showing operationally superimposed against the background of an underlying hunger for finance. It would appear investors have taken an increasingly jaundiced view of prospects over the past few years.

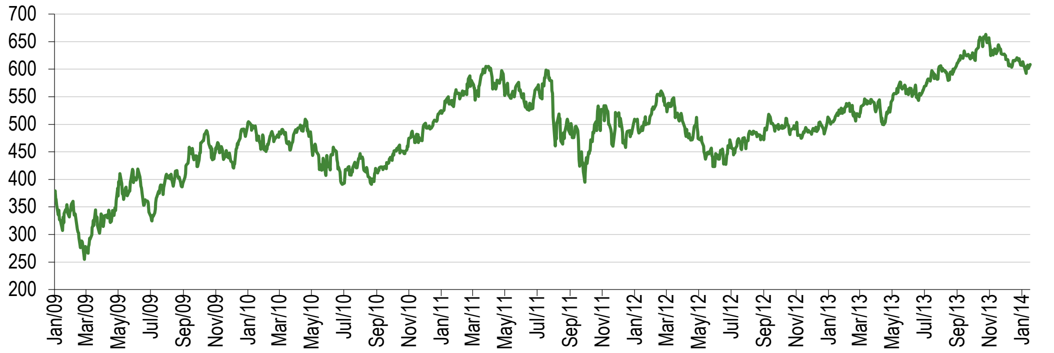
**Exhibit 36: AIM Oil & Gas Index**


Source: Bloomberg

**US: Solid to strong performance by the E&P independents and refinery sector**

Over the past year or so, US upstream oil and gas stocks generally performed solidly in absolute terms, but underperformed a very buoyant wider market. The strongest performances have been turned in by the large and mid-tier capitalisation stocks focused on development activity in North America. In the 12 months to 15 January 2014, for example, the S&P 500 Oil & Gas Exploration and Production Index, the benchmark for the medium and large capitalisation oil and gas independents, showed a gain of 19%. By comparison, the more broadly based S&P 500 Oil & Gas Index, which includes the majors plus the large independents and refinery groups, rose by 14% on the same basis. Both oil and gas indices underperformed the 26% gain in the S&P 500 over the past year. Among the standout performers have been shale pioneers Continental Resources and EOG, which showed gains in the 12 months to 15 January 2014 of 33% and 36% respectively. By contrast, the two largest oil and gas stocks, ExxonMobil and Chevron, have recorded considerably more modest gains of 10% and 5% respectively. The shale-focused stocks have tended to benefit from highly successful development activity in the US and bullish volume trends, while the majors have grappled with sluggish volume trends and significant cost pressures upstream plus a margin squeeze, particularly in downstream international operations.

**Exhibit 37: S&P 500 Oil & Gas Exploration and Production Index**

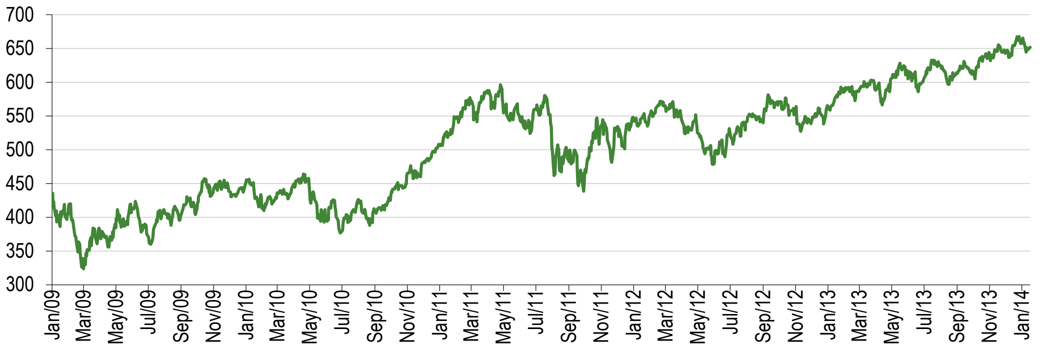



Source: Bloomberg

A particularly interesting development in the oil and gas sector in 2013 was the strength of the refinery stocks. The benchmark S&P 500 Refinery Index rose by 40% in the year to 15 January, thereby comprehensively outperforming the S&P 500. The refinery stocks have benefited from a very positive backdrop in terms of the availability of cost-advantaged feedstock, utilisation rates and volume growth.

Constraining the performance generally of the US E&P sector over the past year was a dip in the fourth quarter and in early 2014 associated with a slide in WTI. Nevertheless, the S&P 500 Oil & Gas Exploration and Production Index is close to a six-year high. Interestingly, the S&P 500 Oil & Gas Index was hovering close to an all-time high in early January 2014.

**Exhibit 38: S&P 500 Oil and Gas Index**




Source: Bloomberg