Oil & gas macro outlook

Swimming in oil

Oil & gas

3 October 2014

The oil market has finally succumbed to fundamental forces and a strong dollar over the past three months or so. Recently, Brent and WTI have been down almost 20% from the June highs. Significantly, geopolitical issues have been downplayed and instead the market has focused on surging production growth in North America and lacklustre demand. The market has indeed been swimming in oil. OPEC will probably attempt to cut production in the coming months but is likely to have difficulty in accommodating non-OPEC production growth plus rising production in Libya and potentially in Iraq and Iran. We believe OPEC has lost control of the market much as in the second half of the 1980s with the game changer this time around being the US shale revolution and the Alberta oil sands. Near to medium term the outlook remains bearish for oil prices.

Supply/demand: Comfortable supply surplus 2014/15

Abstracting from unplanned outages, the oil market globally should be comfortably in surplus in 2014 and quite possibly 2015. In both years we believe the surplus will be at least 0.5mmb/d, even allowing for OPEC production cutbacks. The key factors here are strong non-OPEC production growth led by the US and Canada and lacklustre demand. Non-OPEC controlled production looks like growing by 1.6 to 1.9mmb/d (3%) in 2014 and perhaps 1.5mmb/d in 2015 with the former among the highest growth rates of the past 20 years. Demand growth globally in 2014 and 2015 will probably be a modest 0.9 to 1mmb/d (1%) with a combination of a sluggish economic backdrop, improving vehicle fuel efficiency and fuel conservation measures all acting as constraints. OPEC production cutbacks will cut into the sizeable non-OPEC surplus but are very unlikely to eliminate it completely.

Light crude spreads: WTI discount could widen in Q4

WTI Cushing has performed strongly relative to Brent in 2014, resulting in a sharp narrowing of the spread. At end September the WTI discount was down to about $3/barrel after averaging $10.8/barrel in 2013. The key drivers behind the narrowing have continued to be a sharp decline in inventory at the Cushing tank farm, buoyant US refining activity and several bearish factors impacting Brent including a growing supply surplus in the Atlantic Basin, a slowing Chinese economy and the potential for a pick-up in Libyan exports. We expect the WTI discount to widen in the fourth quarter of 2014 to about $6/barrel to more accurately reflect transportation costs to the Gulf and pipeline start-ups that will bring more oil to Cushing.

Price forecasts: Brent 2014/15 forecasts downgraded

We are downgrading our 2014 Brent forecast reflecting the weaker than expected trend in recent months and increasingly bearish fundamentals in the Atlantic Basin. The 2014 forecast has been reduced from $105.4 to $103.9/barrel. Our WTI forecast for 2014 has been upgraded from $96.3 to $97.3/barrel to reflect the more robust than expected trend in the second and third quarters. The fourth quarter forecast has however been downgraded from $93.5 to $89.5/barrel. Our 2015 WTI forecast has been cut from $91.0 to $88.8/barrel to reflect bearish fundamentals and likely greater than previously expected carryover weakness from 2014.

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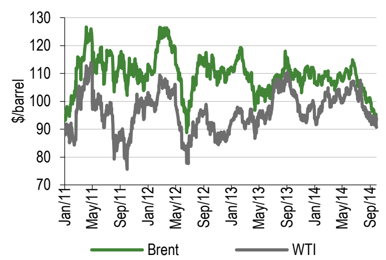
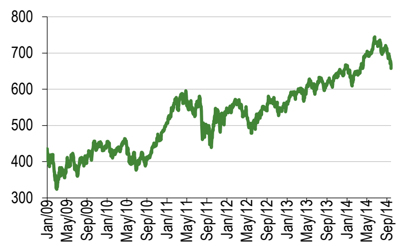
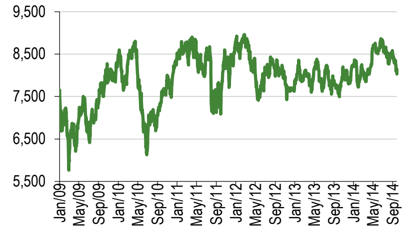
WTI vs Brent



S&P 500 Oil & Gas Index



FTSE 350 Oil & Gas Index



Source: Bloomberg

	WTI $/bbl	Brent $/bbl	Henry Hub $/mmBtu
2011	94.9	110.0	4.00
2012	94.2	112.0	2.75
2013	98.0	108.8	3.73
2014e	97.3	103.9	4.53
2015e	88.8	95.0	4.18

Note: Prices are yearly averages.

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Executive summary

Recent oil price developments: International light crude prices, along with the US inland benchmark WTI trended higher in the first half of 2014 driven by geopolitical factors surrounding Ukraine and Iraq in Q2. A sharp reversal took place in the third quarter with prices falling from the June peak by about 20% and 15% in the case of Brent and WTI respectively. By end September, Brent and WTI were trading at $93.2/barrel and $91.2/barrel which were equivalent to 26-month and 15-month lows respectively. In the early days of October prices continued to soften to under $92/barrel for Brent and $89.5/barrel for WTI. The weakening price trend in recent months reflects a combination of plentiful supplies, growing evidence of lacklustre demand globally, rapidly waning geopolitical concerns and the strong dollar. A reflection of the weakening backdrop in recent months has been the swing from the long-time backwardation in the Brent forward curve to contango.

WTI-Brent spread: The WTI discount to Brent has trended sharply down in 2014. At end September the discount was $3.4/barrel which compares with about $12/barrel at end 2013 and an average $10.8/barrel for 2013 as a whole. The narrowing discount has been despite the continuing Mid-Continent production build-up and reflects a sharp drop in inventories at the Cushing, robust US refining activity, a build-up of a supply surplus in the Atlantic Basin and the greater sensitivity of Brent to the business slowdown in China. At just over $3/barrel the WTI discount is significantly below pipeline costs from Cushing to the Gulf Coast and well below rail costs of about $10/barrel. We believe the WTI discount could widen over the rest of 2014 to better reflect transport costs and the potential for inventories to rise at Cushing following pipeline start-ups.

LLS-Brent spread: The discount between LLS, the Gulf Coast light crude benchmark and Brent that emerged in the second half of 2013 narrowed sharply during the third quarter of 2014. The discount averaged $1.2/barrel in the period after having been as high as $8/barrel in the fourth quarter of 2013. By early October LLS was again trading at a premium to Brent. Given near-record inventories along the Gulf Coast the swing to an LLS premium at first glance appears perverse. The explanation appears to reflect high Gulf Coast refining activity and weak Brent fundamentals. Supply issues suggest a return to an LLS discount of perhaps $2-3/barrel to Brent in due course.

Non-OPEC output: Driven by North America, non-OPEC crude oil has been on a strong upwards trend in 2014. Growth for the year looks like being 1.6-1.8mmb/d or about 3%, which is one of the highest growth rates in the past 20 years. Non-OPEC output should continue to grow strongly in 2015, although the pace may slacken from 2014. We believe a gain of about 1.3mmb/d is plausible. In addition, we would look for a further contribution from OPEC NGLs of 0.2mmb/d. Note from late 2015 production from Brazil's massive pre-salt offshore oilfields should be gaining momentum.

US output: US crude oil output continues to grow strongly driven by intensive development activity in the shale formations of the Great Plains and Texas. Based on EIA data, production in the four weeks to 12 September averaged 8.67mmb/d, up 0.97mmb/d or 12.6% on a year earlier. Looking at 2014 year-to-date production has climbed by 14.5% and is now running at a 28-year high. The EIA is forecasting US crude production of 8.53mmb/d (+14.5%) in 2014 and 9.53mmb/d (+11.7%) in 2015. Production in the latter year will be close to the 1970 record. NGL output has also continued to grow strongly in 2014. In the year-to-date September there has been a gain of 12.6%.

OPEC output: OPEC crude oil production has remained relatively buoyant in recent months and in line with the 'call' of 30mmb/d. Production has been running slightly below a year ago but this was not unexpected. OPEC has recently indicated that it is contemplating a cut in its target production rate from 30.0mmb/d to 29.5mmb/d to accommodate soft demand and non-OPEC production gains. A significant cutback might however be difficult to engineer given the potential for production gains in Libya and Iraq. Iran at this stage is a wildcard given that negotiations are still underway with the world's key powers over its nuclear programme. If there is an accord Iran has indicated that it will be looking to rapidly boost production and exports. The deadline for concluding the negotiations is 24 November.

Global demand: Expectations of oil demand for 2014 and 2015 have recently been significantly downgraded by the IEA. It is now looking for growth of 0.9mmb/d (+1%) in 2014 and 1.3mmb/d (+1.3%) in 2015 which reflect downgrades of 0.15mmb/d and 0.165mmb/d respectively. According to the IEA demand, was soft in the second and third quarters of 2014 with Europe and China very much responsible. Reflecting the sluggish world economy and structural developments (improving fuel efficiency in automotive and aviation) tending to depress usage we believe that further demand forecast downgrades are possible for 2014 and particularly 2015. US domestic petroleum demand has grown modestly in 2014 and in the year to date September has risen by about 1%. In our view a similar outcome is likely for the full year.

Oil supply/demand balance: We continue to expect non-OPEC controlled output growth to comfortably exceed global demand growth in 2014 and in all likelihood in 2015. The non-OPEC surplus could be about 0.8mmb/d including OPEC NGLs which are not subject to quota. Assuming a reduction in OPEC crude output of 0.3mmb/d in line with EIA forecasts the surplus globally would be around 0.5mmb/d. We would expect a similar outcome in 2015. Given the potential for further significant non-output gains a key issue for the supply/demand balance medium term is the extent to which it is accommodated by OPEC.

Crude oil price forecasts: The fundamentals continue to look bearish for both Brent and WTI near to medium term. The underlying issue is the spectre of enduring global supply surpluses. In the light of the weaker than expected trend in recent months and increasingly bearish fundamentals in the Atlantic Basin we are downgrading our Brent forecast from $105.4/barrel to $103.9/barrel. Our Brent forecast for 2015 has also been reduced from $99.5/barrel to $95.0/barrel reflecting greater than previously expected carryover weakness and the broader issue of bearish fundamentals. For WTI we have raised our 2014 forecast from $96.3/barrel to $97.3/barrel to reflect the stronger than expected showing in the second and third quarters. We have, however, downgraded our WTI forecasts for the fourth quarter of 2014 and 2015 as a whole. The new forecast for the latter is $88.8/barrel against $91.0/barrel previously.

US natural gas fundamentals: So far in 2014 US natural gas production has grown strongly driven by the new prolific Appalachian shale plays (Marcellus and Utica) plus by-product gains stemming from shale oil plays. Through June 2014 production was up 5.2% on a year earlier while in late September the consultancy Bentek Energy pointed to a year-on-year gain of 7.6%. Extreme winter weather boosted demand in the first quarter of 2014 but subsequently appears to have slowed significantly reflecting in part the relatively cool summer across much of the US. Although below the five-year average gas inventories appear reasonably comfortable presently for all but the most extreme winters. Note the strong production performance in 2014 has been despite depressed dry gas drilling activity over a sustained period.

US natural gas prices: US natural gas prices have trended down over recent months reflecting strong supply growth and lagging demand. After averaging $5.43/mmBtu in the first quarter of 2014 the key traditional Henry Hub, Louisiana benchmark was down to around $4/mmBtu in late September. Given surging production in the Marcellus and Utica, the Henry Hub however is losing its relevance as the key US benchmark. The Dominion South hub in Appalachia is arguably vying for leadership. Here natural gas prices were down to $2/mmBtu or lower in late September which raises major issues surrounding profitability for dry gas producers. We are leaving our 2014 Henry Hub price forecast intact at $4.53/mmBtu. Our forecast for 2015 however has been downgraded from $4.33/mmBtu to $4.18/mmBtu reflecting the growing evidence of a loosening supply/demand balance in recent months and the expectation that this trend will persist.

EDISON

Crude oil market dynamics

Price overview

Market developments: Prices under heavy pressure in third quarter

Recent months in retrospect: International light crude oil prices, along with the US inland benchmark WTI, trended higher in the first half of 2014 from the levels of late 2013. Towards the end of June 2014 prices were approaching the high end of the recent trading range with Brent at around $115/barrel and WTI at $107/barrel. Compared with end 2013 these prices were up 4.0% and 9.0% respectively. The upward trend in the first half was very much a second quarter phenomenon, given the subdued tendency in the early months of 2014. Between the first and second quarters of 2014 Brent climbed on average 1.8% while WTI was up a more pronounced 4.5%.

Exhibit 1: Brent crude oil price trend

Source: Bloomberg

Rising oil prices in the second quarter stemmed largely from geopolitical factors plus specifically in the case of WTI the sharp rundown in inventories at the Cushing, Oklahoma tank farm, the delivery point for Nymex crude. In terms of geopolitics the key issues were the disruption to supplies from Libya against the backdrop of intense factional fighting, the intensification of the Ukrainian crisis and most significantly the onward march of the Islamic State (IS, formerly an offshoot of Al-Quaeda known as ISIS and ISIL) forces in Iraq. In June the upward trend in prices was given added impetus by the collapse of the Iraqi army and the capture by IS of Mosul, the second largest city in Iraq. Subsequently, the large Kirkuk oilfield was under threat along with the oilfields and newly constructed pipeline infrastructure to the north in Kurdistan

Since end June 2014, both international and US prices have come under heavy pressure. In fact, the slide has been one of most sustained and pronounced since 2011. By the end of September Brent had fallen to a recent low of $93.2/barrel while WTI was down to $91.2/barrel for declines of 19% and 15% respectively from the June 2014 highs. The former and latter prices were around 26 and 15-month lows respectively. Compared with a year earlier prices at the low points at the end of September were down 14.4% for Brent and 12.4% for WTI. Despite the dip in recent months the underlying trend in international light oil prices since early 2011 remains flat.

Exhibit 2: WTI crude oil price trend

Source: Bloomberg

Depressing prices over the past two or three months have been plentiful supplies combined with evidence of lacklustre demand, rapidly waning geopolitical concerns and the strong dollar. Interestingly the weakness in oil prices in recent months has coincided with a broader downturn in commodity prices. Weak fundamentals are not new elements in the equation. It should have been obvious for some time that market fundamentals are less than robust given a marked upturn in non-OPEC output, OPEC production roughly in-line with the 'call' and a still non too buoyant world economy. Importantly, non-OPEC supply has continued to be buoyed by strong output growth in North America while OPEC output has been supported by relatively high levels of production in Saudi Arabia and the UAE. Effectively, these two have been able to at least offset the production losses in Libya, Iran and Nigeria. Significantly, Libyan exports restarted in August following the reopening of key terminals in the east of the country. These terminals had been closed for about a year.

The IEA's (International Energy Agency, the energy watchdog for the OECD) significant downgrading of its global petroleum demand forecasts for 2014 and 2015 caught the market by surprise on September 11 resulting in a decline in oil prices on this date. The downgrade for 2014 reflected evidence of a weak showing in the second and third quarters particularly in Europe and China.

Geopolitics downplayed: Given weak fundamentals and the ability of Saudi Arabia to offset outages in OPEC, the oil market for the moment at least appears with justification prepared to downplay geopolitical issues. Specifically in the case of Iraq, it has become apparent post the Mosul debacle that the US has drawn a line in the sand vis-à-vis IS and furthermore is now working to neutralise if not destroy the organisation. It seems unlikely that the major oilfields of southern Iraq or for that matter those located in the north would be allowed to fall into the hands of the IS.

At the time of writing the key geopolitical area of uncertainty regarding oil markets is arguably Ukraine. There is an outside chance that an escalation of the conflict between Ukraine and separatist forces supported by Russia could ultimately lead to an interruption of energy supplies, although the market is probably correct in downplaying the risk. For the record OECD Europe's net imports of petroleum products in 2013 were 4.3mm b/d or 44% of the total according to the IEA. Effectively these imports can't be offset by any other source. The loss of all or even a significant part of existing Russian supplies would have disastrous consequences for the European economy. By the same token exports of energy are Russia's dominant source of income accounting for 70% of exports and 52% of the federal budget.

Arguably, we are nearing the end game in Ukraine reflecting the inability of government forces to defeat the separatists and the West's lack of leverage in the region militarily. The solution to the crisis may involve the quasi neutrality of Ukraine vis-à-vis the EU and NATO and the establishment of a federal structure for the country in which the Russian speaking zones in the east have substantial autonomy. Since the ceasefire was announced on 5 September developments in Ukraine and particularly the decision to grant self rule to the eastern provinces of Donetsk and Luhansk have tended to support this view. It is, however, an open question as to when conditions in Ukraine will have stabilised to allow a lifting of sanctions on Russia.

Supply-demand dynamics

Non-OPEC supply: North America drives production to record levels

The trend in non-OPEC output so far in 2014 has remained strongly upward. We believe production is running at record levels. Based on IEA data, non-OPEC liquids production was running at about 56.0mm b/d on average in the first half of 2014 for a year-on-year gain of approximately 2mmb/d or 3.7%. During the third quarter production growth has probably eased to about 1.3mmb/d, according to the IEA, reflecting tougher year-on-year comparisons and slippage in production rates in several countries including Mexico, Russia and Colombia. Growth will probably continue to ease in the fourth quarter due among other factors to a slightly less robust trend in North America but should still be highly significant at about 1mmb/d.

Overall, the IEA is looking for non-OPEC liquids production in 2014 to average 56.3mmb/d, up 1.6mmb/d or 2.9% on a year previously. The latest forecast constitutes a 0.1mmb/d increase from a month or so ago. We believe the risks to 2014 are to the upside. Interestingly, the EIA (Energy Intelligence Agency, the statistical arm of the US Department of Energy) is looking for a gain in non-OPEC liquids in 2014 of a significantly greater 1.8mmb/d. The EIA, however, has not changed its forecast in recent months. Forecast non-OPEC output growth in 2014 will be one of the strongest performances of the past 15 to 20 years.

Growth in non-OPEC liquids production continues to be driven largely by the US and Canada. According to the EIA, production in the first half of 2014 was up 1.51mmb/d or 12.7% and 0.36mmb/d or 9.0 % in the former and latter respectively. Overall, North America accounted for 88% of first half production growth. US production continues to be driven by rapid development of shale and tight reservoir formations but later this year an additional positive should be the start-up of new GOM (Gulf of Mexico) fields. Canadian production is being propelled largely by the Alberta oil sands but development of tight reservoir formations in Alberta such as the Duvernay and Bakken is also playing a part. Oil sands production is currently being driven in particular by the ramp-up of Imperial Oil's Kearl and Cenovus/ConocoPhillips Christina Lake projects. Seasonal maintenance will trim oil sands output growth during the third and fourth quarters but Canadian liquids production should still be up O.29 mmb/d or 7% for 2014, according to the EIA.

Outside North America a key development so far in 2014 has been the apparent stabilisation of the North Sea production trend after a long period of decline. Stabilisation reflects actions to revamp existing fields which for the moment, at least, have been successful in offsetting high rates of depletion. North Sea production will probably slip noticeably in the third quarter due to the seasonal heavy maintenance schedule planned for the UK sector. Barring eventualities North Sea output nevertheless looks like being broadly unchanged in 2014 but this probably only constitutes a hiatus before the downward trend is resumed.

Medium to long term, Brazil is potentially one of the largest new sources of non-OPEC crude oil reflecting the massive offshore pre-salt discoveries of 2006/7. There is now some evidence to suggest that development efforts are gaining traction. After a solid start to the year, production remained buoyant in the second quarter of 2014 based on EIA data. During the first half production, including ethanol, averaged 2.66mmb/d, up 7.3% from a year earlier. Importantly, the performance of pre-salt wells has been outstanding in many cases with production of 30,000b/d or more. According to Petrobras, production has continued to firm in the third quarter, although this has not been reflected in the latest EIA forecast. Petrobras is in the throes of installing in the Santos basin two 0.15mmb/d FPSOs with start-up scheduled in the fourth quarter of 2014. The company is forecasting a 7.5% gain in crude production for the full-year to almost 2.2mmb/d. Independent observers, however, are more sceptical and are looking for an increase of 5% or less. A major issue continues to be high rates of depletion in Brazil's mature fields.

The non-OPEC output trend should remain strongly upward in 2015, although the pace might slacken compared with 2014 based on the latest forecasts made by the IEA, EIA and OPEC. All three are pointing to growth of about 1.3mmb/d (about 2.2%) from 2014. Significantly the IEA recently increased its forecast for 2015 by 0.1mmb/d to 57.6mmb/d. Once again the upward trend in 2015 is expected to be very much a North American (excluding Mexico) phenomenon. According to the EIA, US production is scheduled to rise by 1.21mmb/d while Canada could see a gain of 80,000b/d. The latter in our view appears on the pessimistic side given the anticipated start-up of several new oil sands projects and the carryover effect of earlier start-ups.

The EIA's latest output forecast for 2015 is slightly down from earlier in the year. Key areas of weakness anticipated in 2015 include Mexico and the UK with declines of 0.07mmb/d and 0.18mmb/d respectively. Surprisingly perhaps in the light of the intensive development activity taking place in the pre-salt along with the excellent well flow rates being achieved, the EIA is only looking for a modest 0.02mmb/d increase in Brazilian liquids production in 2015. We believe Brazil offers scope for a substantially greater gain next year which could conceivably lift 2015 non-OPEC output growth closer to 1.4mmb/d or even 1.5mmb/d.

What does post 2015 look like? We believe that prospects for the buoyant trend in non-OPEC growth continuing over the balance of the decade are in principle favourable. Growth of over 1mmb/d per annum is a very real possibility. Key positives include the following:

- Continuing tight reservoir development activity in North America.
- The potential to expand the shale revolution outside North America.
- Continuing development of the Alberta oil sands.
- Planned unlocking of the massive pre-salt discoveries offshore Brazil.
- The giant Kashagan development in the Kazakh sector of the Caspian Sea. This has been subject to interminable delays with the latest being due to a highly toxic hydrogen sulphide gas leak but production from this source could be gathering pace in earnest from 2016.

Against these positives the petroleum industry, of course, faces many challenges in boosting production. Not least of these are high rates of depletion as mature fields enter the decline phase. Recently another problem to emerge concerns the imposition by the west of financial and technical sanctions on the Russian oil and gas industry. Near term these are unlikely to exert much influence over production rates but will probably do so if sustained over a long period. The key exploration and development opportunities in Russia relate to eastern Siberia, the Arctic offshore region and the Bazhenov shale formation in western Siberia. Deepwater drilling and tight reservoir development all require western technology and to some extent sources of capital if work is to be undertaken expeditiously. The west can ill afford to allow Russian production and exports to fall below current levels.

OPEC supply: Production tracked around 30mmb/d until recently; cuts in the pipeline

OPEC crude oil production has remained relatively buoyant in recent months and in line with the target production rate of 30mmb/d. According to the IEA, production averaged 30.0mmb/d in the first and 30.1mmb/d in the second quarter. Production in the first half was slightly below a year earlier but this was not unexpected and was close to the OPEC 'call' (world demand less non-OPEC supply and OPEC NGLs/non-conventionals). In July, OPEC production firmed to about 30.4mmb/d before slipping to 30.3mmb/d in August. The former was the highest in five months based on IEA data. The relative strength of OPEC production might appear surprising at first glance given the slump in Libya, ongoing disruptions to production in Nigeria and sanctions constrained Iran. As in earlier months, the explanation to the apparent conundrum reflects rising output in Saudi Arabia and Iraq. During the first half of 2014 crude production was up 4.0% and 6.2% to respectively on a year ago. At just over 10mmb/d production Saudi production was close to a 30-year high in July.

Interestingly, the modest dip in OPEC crude production in August was largely a response to falls in Saudi Arabia and Iraq. Compared with the prior month, Saudi production fell by about 0.4mmb/d while Iraqi output was off by 0.06mmb/d. Apparently, Saudi exports to the US have come under heavy pressure of late. Rising Libyan output acted as a partial offset to falling Saudi output in August and has indeed supported the overall OPEC trend over the past two or three months. According to the IEA, Libyan output was running at 0.53mmb/d in August, well up from the low point in March 2014 of 0.15mmb/d, albeit still considerably the recent peak level of 1.4mmb/d recorded before the terminal blockades commenced in the third quarter of 2013. With the export terminals now open Libyan production could trend higher in the coming months but damage to infrastructure and declining reservoir pressure at some fields will probably severely limit gains. According to the IEA, the maximum sustainable production rate near term is probably about 0.8mmb/d. This compares with theoretical capacity of about 1.6mmb/d.

After reaching a 35-year high of 3.65mmb/d in February 2014, Iraqi production has trended down and in August was running at 3.1mmb/d based on IEA data. The decline reflects lower output in the northern Kirkuk operations, which have been heavily impacted by a combination of sabotage to the export pipeline to the Turkish terminal of Ceyhan and the closure of the Baiji refinery north of Baghdad due to an attack by IS forces. Output in the autonomous Kurdish region appears to have been pretty much maintained in recent months at about 0.35mmb/d despite its close proximity to fighting between Kurdish Peshmerga forces and IS. Kurdish production is either used in local refineries or exported to Turkey by truck and since May by a new pipeline to Ceyhan. Export shipments from Ceyhan, however, have so far been largely successfully challenged by the Baghdad central government as illegal.

Significantly, exports from Iraq's southern operations have trended higher in 2014 and in July were running at 2.44mmb/d, around 0.3mmb/d above a year earlier. Export terminal capacity here is in the throes of being boosted by more than 0.5mmb/d from end 2013 levels. Shipments from the southern terminals could therefore conceivably increase in the coming months. Iraqi production in 2014 looks like falling short of the Iraqi government's 4mmb/d objective given a series of technical and weather related issues along with the Kirkuk-Ceyhan pipeline and Baiji refinery outages. The Kurdistan authorities may be able to restore exports from Kirkuk in due course if the fields can be connected with the new pipeline to Ceyhan.

OPEC contemplates an output cut OPEC has recently suggested that its output target in 2015 for crude could be reduced from 30mmb/d to 29.5mmb/d. This reflects an expected drop in the 'call' on OPEC crude stemming from rising non-OPEC production. Interestingly, the tentative target is in line with the EIA's forecast OPEC production in 2015. In recent years OPEC has generally achieved a high degree of compliance with its production targets. This, however, has probably owed more to good fortune in terms of major production outages. Next year it might be more difficult to achieve compliance if both Libya and Iraq significantly boost production, remembering that the former is operating well below quota and the latter is unencumbered by quota restrictions.

Iran could also pose a problem for OPEC in the event of an accord with the western powers over its nuclear programme. Not surprisingly, Iran has suggested that it will want to rapidly boost production subsequent to an accord being signed from the current level of about 2.7mmb/d to its sustainable capacity of approaching 4mmb/d. In the event of Iraq, Iran and Libya all wishing to significantly increase production, it would be incumbent, as always, on Saudi Arabia to make an offsetting cutback to restore balance. Whether it would wish to do this is an open question.

Global demand: Sluggish picture, IEA cuts forecasts

Evidence of sluggish oil demand globally has emerged of late and surprised the market along the way. The key news item has been the IEA's recent decision to significantly cut its demand forecasts for both 2014 and 2015. The forecast for the former was cut by 0.15mmb/d to 92.6mmb/d while that for the latter was reduced by 0.165mmb/d to 93.8mmb/d. Based on the new forecasts growth is 0.9mmb/d or 1.0% for 2014 and 1.2mmb/d or 1.3% for 2015. By comparison, the EIA is looking for growth of 1.0mmb/d and 1.3mmb/d on the same basis. Early in 2014 the EIA, IEA and OPEC had been forecasting demand growth this of more like 1.1 to 1.4mmb/d so we are witnessing a significant downgrade. For perspective, the IMF's current forecasts for world GDP growth are 3.4% and 4.0% for 2014 and 2015 respectively. Downgrades are likely to these GDP forecasts in October.

The proximate cause of the IEA's forecast downgrades reflect the weak showing for demand in the second quarter and the carryover of the trend into the third quarter. The IEA described the recent slowdown 'as nothing short of remarkable'. However, given the far from robust economic backdrop and widespread adoption in many parts of the world of measures aimed at enhancing fuel efficiency and conserving fuel it was not totally surprising in our view. Indicative of the sluggish demand picture according to the IEA, was year-on-year global demand growth of only 0.48mmb/d or 0.5% in the second quarter of 2014. This was down from about 1.1mmb/d in the first quarter.

The IEA very much attributed the slowdown to a weak showing in Europe and China. There is of course nothing new about declining European demand. Between the peak in 2006 at 15.7mmb/d and 2013 OECD-Europe demand fell by 2.1mmb/d or 13.4% to 13.6mmb/d. The drivers here are the decidedly lacklustre economic backdrop, the improving fuel efficiency of the light vehicle fleet and possibly lifestyle changes leading to fewer miles driven. The EIA is pointing to a further drop of 0.9% to 13.5mmb/d in 2014 but based on the IEA's recent comments implying incipient weakness there could be some downside risk to this forecast. The EIA is currently suggesting a broadly flat trend for oil demand in 2015.

It has been apparent for some time that China's oil demand is no longer surging. Between 2000 and 2010, demand rose by about 7%pa to 9.0mmb/d. In several years during this period growth was 0.5mmb/d or over. Growth slowed in the three years to 2013 to 3.7%pa taking demand to 10.1mmb/d. In absolute terms, consumption increased on average by 0.37mmb/d pa between 2010 and 2013. The EIA is forecasting growth of 3.5% or 0.37mmb/d in 2014 and 3.9% or 0.43mmb/d in 2015. Slower demand growth in China parallels in part the broader economy but also reflects fuel conservation and efficiency enhancement measures driven by an official desire to restrict emissions and energy imports. We believe that a slowing economy combined with the fuel efficiency and energy import issues will continue to impact Chinese demand in the coming years. Indeed, these factors will probably intensify in significance.

As far as OECD demand is concerned modest growth in the US and Canada has provided a modicum of support in 2014. This however has been insufficient to offset the weakness in Europe and Japan. Demand in the latter is being significantly impacted by the switch in the power station sector from oil to lower cost alternatives particularly in the form of coal. The switch will probably gain momentum in 2015 as nuclear reactors are restarted following stringent safety checks in the wake of the Fukushima nuclear disaster of 2011. The EIA is forecasting declines in Japanese oil demand of 3% in 2014 and 4% in 2015. Overall, the EIA is looking for OECD demand to drop 0.5% in 2014 and to increase by 0.2% in the following year. As has been the case for a number of years, growth globally is being driven by the non-OECD world. Growth here is forecast by the EIA at 2.8% and 2.7% in 2014 and 2015 respectively.

Looking at the various global demand forecasts we believe that the IEA's 0.9mmb/d gain for 2014 is now realistic. We suspect however that the forecasts of the IEA and EIA for 2015 are too bullish given current economic trends and developments on the fuel efficiency and fuel conservation fronts.

Provisionally we would say demand growth of around a 1mmb/d is more plausible than consensus forecasts of 1.2/1.3mmb/d. Given the transition generally to slower economic growth in recent years and the structural changes taking place in the oil market we would argue that growth in global oil demand is unlikely to greatly exceed 1mmb/d near to medium term. This view would certainly be reinforced if there is a movement to sharply reduce fuel subsidies in the Middle East, Venezuela and parts of Asia. Some action has already been taken on this front by the likes of Iran, India and Indonesia but subsidies remain absurdly large in the Gulf, Saudi Arabia and Venezuela (gasoline prices of less than 5cts/gallon). In the case of the Middle East, oil consumption could also be sharply reduced by substituting abundant supplies of natural gas for oil in power generation. Incentives to cut subsidies include budgetary pressures, emissions and raising oil export capacity.

Global supply/demand balance:

Abstracting from major unplanned outages, the oil market globally looks like being very comfortably in surplus in 2014 and quite possibly in 2015. Assuming the IEA's previously discussed forecast gain in non-OPEC crude output of 1.6mmb/d, a further gain in OPEC NGLs of 0.1mmb/d and demand growth of 0.9mmb/d the surplus would be 0.8mmb/d. OPEC crude output will however be somewhat lower in 2014 so allowing 0.3mm/b/d for this in line with the EIA's forecasts, the surplus would decline to a still significant 0.5mmb/d. This compares with approximate balance in 2013.

Based on the same analysis the growth in non-OPEC liquids output and OPEC NGLs could exceed world demand growth by perhaps 0.5mmb/d in 2015. This assumes 1.3mmb/d for non-OPEC crude, 0.2mmb/d for OPEC NGLs and 1mmb/d for demand. Allowing for a further cut in OPEC production of 0.1mmb/d in line with EIA forecasts would reduce the overall surplus to 0.4mmb/d. As always, OPEC production is the wildcard. It is possible that a deeper cut in production will be implemented by Saudi Arabia to balance the market. As noted earlier however this could be difficult to orchestrate if production is trending upwards in Iraq, Iran and Libya. Another potential scenario is that Saudi Arabia allows the market to remain in surplus over an extended period with the aim of putting financial pressure on relatively high cost producers and hence on investment in new capacity. Saudi Arabia probably has the financial resources for such a strategy.

Given what we see as the base case outlook for significant non-OPEC production gains and subdued global demand growth, we believe there is likely to be tendency for the oil market to flirt with a supply surplus medium term.

US scene

Oil production: Strong growth trend continues

Following a brief weather related slowdown at the beginning of the year, US crude oil production subsequently regained strong upward momentum. Based on EIA data, production in the four weeks to12 September 2014 averaged 8.67mmb/d, up 0.97mmb/d or 12.6% on a year earlier. For the period there was a year-on-year gain of 14.2% to 8.26mmb/d in the Lower 48 states and a decline of 11.4% to 0.42mmb/d in Alaska. The latter was impacted to a considerable extent by heavy maintenance activity. Looking at the week ended 12 September production came in at 8.84mmb/d up a hefty 0.25mmb/d on a week previously and 1.0mmb/d on a year ago. It was also the highest level of output since March 1986 and 3.8mmb/d or 77% above the low point in 2008. Interestingly the bulk of this gain has occurred since 2010, a highly impressive achievement. Production on an underlying basis continues to be driven by the shale and tight reservoir formations of the Great Plains and Texas. Specifically in the case of early September, production was also supported by a rebound in Alaskan production following the completion of pipeline maintenance. Taking the year-to-date 12 September 2014, US crude production has increased from a year earlier by 14.5% to 8.36mmb/d reflecting a gain of 15.8% for the Lower 48 and a 2.8% decline for Alaska.

US production of NGLs and renewable has also shown strong growth in 2014. In the four weeks to 12 September NGL production was 2.96mm b/d, up 19.1% on a year earlier while ethanol output was up 11.0% to 0.92mm b/d. Total domestic supply of liquids in the four weeks to 12 September at 12.11mmb/d probably entails the US being the world's largest supplier of hydrocarbon liquids and renewables (ethanol and bio-diesel) combined.

The EIA is currently looking for US crude production in 2014 of 8.53mmb/d, up 14.5% on 2013 and a significant upgrade from the 8.37mmb/d forecast of earlier in the year. Note, over the remainder of 2014 and more particularly in 2015 production should receive a major boost from development activity in the GOM (Gulf of Mexico). Production here has been on the slide in recent years. For 2015 the EIA is forecasting US crude production to average 9.53mmb/d which is very close to the 1970 all-time high of 9.6mmb/d. In all probability this will be comfortably exceeded in 2016. Total liquids production is expected by the EIA to come in at 12.49mmb/d in 2014 and 13.70mmb/d in 2015 for year-on-year gains of 12.9% and 9.7% respectively. Production as a proportion of consumption will be about 66% in 2014 and 72% in 2015.

US crude oil imports/exports: Imports continue to trend down

US crude oil imports have continued to fall in 2014 reflecting the build-up of domestic production. Taking the four weeks to 12 September imports averaged 7.76mmb/d, down a modest 3.7% on 2013. In the year-to-date the decline has been somewhat greater at 5.2%. Crude imports are now running 28% below the 2005 peak of 10.7mmb/d. The EIA's latest forecasts call for US imports to decline in 2014 by 9% to around 7mmb/d. A further fall of 13% to 6mmb/d is expected in 2015. Canada is by the largest exporter to the US accounting for around 40% of imports.

Exports of crude have been largely prohibited since 1975 for energy security and domestic fuel product pricing reasons. The key exception to the embargo is Canada subject to the proviso the crude is refined in the country. Lightly processed condensate along with natural gas liquids can also be exported. Exports in the year-to-date have averaged a modest 0.156mmb/d. The pros and cons of exporting crude continue to be hotly debated. Those in favour, mainly the independent oil companies, stress tight light crude refining capacity in the US, the desirability of capturing international price premiums and the potential boost to exploration and development activity. The opposition, mainly the independent refiners, points to the possibility of higher domestic crude and hence refined product prices and also the scope for greater value added by exporting refined product rather than crude. The competitiveness of the US refining sector and the value-added and refined product pricing arguments may prove crucial in preventing an early lifting of the export ban. Light crude refining capacity is also being expanded while the discounts on domestic crudes have narrowed considerably over the past year or so. It may also be argued that the US is still a highly significant crude importer so other things being equal it would not make a great deal of sense to export crude and then import an equivalent amount.

While a broadly-based liberalisation of the export embargo seems unlikely near term given some genuine objections and the political unpopularity of the cause, there may be scope from some specific exemptions where it makes industrial sense. A case in point could be exports to Mexico as part of a swap agreement.

Net product trade balance: Net export position continues to widen

The swing from a net import to a net export position in refined products has been a highly impressive development in US petroleum industry circles in recent years. During 2014 the build-up in net exports has continued apace driven by both falling imports and rising exports. Taking the year-to-date 12 September 2014, imports fell by 9.9% to1.80mmb/d from a year earlier while exports were up 15.5% to 3.39mmb/d. The net export balance averaged 1.75mmb/d in the four weeks to 12 September against 1.35mmb/d a year previously and 1.40mmb/d in calendar 2013. For comparison, in 2005 net imports were running at a peak rate of 2.45mmb/d so there has been a swing since then of 4.20mmb/d.

The continuing strong underlying trend in the net export balance reflects a combination of several factors. These relate to the following:

- US refining industry's powerful competitive position which stems from the ready availability of internationally competitive supplies of feedstock and natural gas. Note that natural gas is used both as a feedstock in producing hydrogen and as a fuel. According to leading refinery independent, Valero Energy, its Gulf Coast refineries have a cost advantage over those in Europe of $1.89/barrel due purely to lower natural gas prices. US Gulf refineries also tend to have the advantage of generating high middle distillate yields, the product line showing the strongest growth.
- The proximity of the Gulf Coast refining complex to buoyant markets in Latin America where refining capacity tends to be capacity constrained. Latin America accounts for over 50% of exports.
- The closure of refining capacity in the Atlantic basin and a spate of technical problems at Latin American refineries that have constrained capacity.

Planned capacity additions in Brazil, Colombia and Mexico could alleviate some of the capacity tightness in Latin America in due course. These additions, however, are tending to take longer than expected to bring on-stream while the US competitive advantages in terms of feedstock are likely to endure for the foreseeable future.

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

Texas is not only the largest oil producing state in the union but also one of the world's leading oil producing provinces. Production in Texas has undergone an impressive renaissance since the mid-2000s low of1.07mmb/d. The trend in 2014 has remained strongly upward. In June 2014, the most recent month for which EIA data is available, production was 3.07mmb/d up 21.8% on a year earlier and the highest level in over 30 years. On a year to date basis Texas production has risen from 2013 by a slightly greater 23%.

Texas production continues to be very much driven by the rapid development of the prolific Eagle Ford shale play in the Western Gulf Basin in the south west of the state and several stacked plays (Spraberry, Wolfcamp, Avalon/Bone Spring and Cline) in the Permian Basin in the northwest. Based on EIA data, production from the Eagle Ford and Permian is currently running at about 1.5mmb/d and 1.7mmb/d respectively. About 10% of the latter is attributable to New Mexico. Based on recent rates of travel and given high rates of drilling activity, production from both the Eagle Ford and Permian (Texas) could be 1.7-1.8mmb/d by end 2014. This might suggest production for Texas in total of about 3.4mmb/d by 2014 year end which would equal the 1972 record.

North Dakota: Production now comfortably above 1mmb/d, 2mmb/d maybe on the cards

North Dakota has established itself over the past two or three years as comfortably the second largest oil producing state in the US after Texas. Currently it accounts for about 13% of US output. After a brief weather-related hiatus in late 2013 and early 2014 the North Dakota production regained strong upwards momentum. Significantly, production exceeded 1mmb/d for the first time in April. For July the North Dakota Department of Mineral Resources (DMR) reported production of 1.11mmb/d, up 27% on a year earlier and a new record. This is also in line with the year to date gain. The gain from the previous month of 1.7% was, however, somewhat lower than generally expected. It should be noted that North Dakota's emergence as one of the world's major oil producing provinces has occurred within the past five years, an outstanding achievement.

Drilling and completion activity has been on a robust trajectory of late. Indicative of this has been the 19% year-on-year gain in spuds in the three months to July. The average number of spuds over three months of 223 also reflects a historically high level of activity as does the recent rig count in

North Dakota of 192. Significantly for the longer term picture, development permitting has been running at an historically high level of late. In July 265 permits were granted, up 56% on a year ago. Robust trends in drilling activity point to a continuation of the strong production trend over the coming months barring extreme weather conditions. We believe that by end 2014 North Dakota production could be running at about 1,29mmb/d. The DMR's forecast of 1.6mmb/d looks by mid-2017 looks plausible. Interestingly, Harold Hamm the Continental Resources Chairman, CEO and pioneer of the Bakken has suggested that production from the Bakken/Three Forks petroleum system could ultimately exceed 2mmb/d.

Importantly, North Dakota has recently announced restrictions on gas flaring which will come fully into force in 2015. The aim is to reduce gas flaring from about 30% of production to 23% in January 2015, 10% by 2020 and potentially 5% subsequently. Failure to comply will result in fines and enforced well production cutbacks. High rates of flaring in North Dakota have reflected a desire to speed development of considerably more lucrative oil production and the absence of a large local market for gas. The drawback to this approach is clearly GHG emissions and wasted energy. Initially, at least, the ruling on flaring could curb crude oil production as new facilities are added for processing and transporting gas. The lower than expected growth in oil production in July has been attributed by the DMR to the flaring issue and the need to install new infrastructure.

Monterey formation potential downgraded

In May 2014 the EIA announced that the potential recoverable reserves for the Monterey shale formation in central California had been downgraded by 96% from 13.7bn barrels to 600mm barrel. This followed tests that revealed extraction was much more difficult than previously expected using horizontal drilling and fracking. The underlying problem was unsuitable geology stemming from widespread folding and faulting. In principle the resource base is in-situ but there are major difficulties with stimulating flow. Acidisation of rock formations may provide a long term solution but considerable research is apparently needed to unlock the potential riches of the Monterey.

The downgrade of the Monterey contrasts with the upgrades of shale potential that is tending to take place elsewhere. Continental Resources, for example, now estimates that the Bakken petroleum system including the Three Forks formation could hold 45bn barrels, assuming a 5% recovery rate. This would imply a supergiant field and way beyond the expectations of virtually anyone just 10 or even 5 years ago.

Domestic demand: Growing modestly

US domestic petroleum demand has increased modestly so far in 2014. In the four weeks to 12 September demand averaged 19.37mmb/d, up 1.2% on a year earlier. Growth by product line was as follows: gasoline, the largest 0.4%, kerosene 5.4%, distillates -2.6%, fuel oil -32.1%, propane/propylene -5.1% and miscellaneous 10.9%. The key surprise was the decline in distillates given the close relationship between the usage of this product group and economic activity and the relatively favourable economic backdrop. Overall, however, petroleum demand broadly remains on the plateau that has existed since 2008. On a year-to-date September 2014 basis petroleum product demand is up on a year ago by 1.0% with gains of 0.8% for gasoline, 3.1% for kerosene and 2.1% for distillates. Fuel oil and propane have shown declines of 22.5% and 12.5% respectively while miscellaneous shows a gain of 6.3%.

The EIA is looking for a marginal 0.2% decline in petroleum product demand between 2013 and 2014 to 18.92mmb/d. Given the year-to-date performance and the reasonably buoyant US economy this appears unduly bearish at first glance. Demand was however significantly boosted in the fourth quarter of 2013 by a record but rain sodden grain harvest. This required intensive use of drying equipment based on propane. This year the grain harvest looks like being even larger but the EIA has assumed that propane usage will fall well short of the levels of 2013. Clearly however a record grain harvest prospectively will help underpin diesel consumption both in terms of the agricultural sector and highway and rail transportation. Significantly, the EIA is showing growth in distillate fuel consumption in 2014 of 4.2%. Gasoline consumption in 2014 is forecast by the EIA at 8.82mmb/d, down 0.2% on 2013. Bearing in mind the year-to-date showing and expectations of a buoyant US economy in the second half this appears on the conservative side even allowing for improving light vehicle fleet fuel efficiency. A similar conclusion applies to the EIA's overall forecast for US petroleum product demand in 2014.

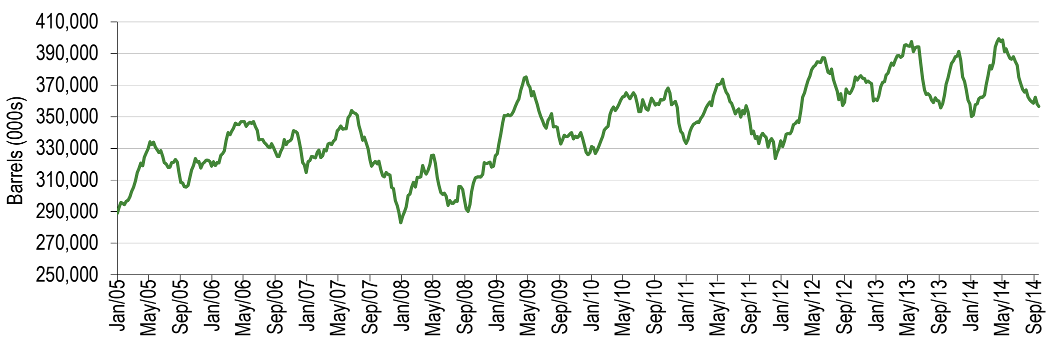
For 2015 the EIA is forecasting a return to modest growth in US petroleum demand. Overall it is looking for a 0.8% gain to 19.08mmb/d. The key areas of strength are expected to be distillates with a gain of 1.8% and hydrocarbon liquids mainly in the form of propane and ethane which are forecast to show a growth of 0.15mmb/d. The growth in distillates we believe mainly reflects growing freight transportation needs in a reasonably buoyant economy while increasing ethane and propane usage largely stems from rising chemical industry activity. Gasoline consumption in 2015 is expected to show another marginal fall presumably reflecting the improving fuel efficiency factor. Vehicle usage however is a wildcard in this context. Falling gasoline prices, if sustained, could combined with a buoyant economy conceivably give gasoline demand a modest boost in 2015. The EIA's forecasts for petroleum demand growth in 2014 and 2015 of -0.2% and +0.8% clearly lag by a wide margin its GDP growth assumptions of +2.1% and 2.8%.

Inventories

Crude oil: Inventories remain seasonally high

US commercial crude oil inventories have been running at a seasonally high level of late, which perpetuates a tendency that has been apparent for some time. Based on EIA data, crude oil inventories stood in the week ended 12 September at 362.3mm barrels. This was up 6.7mm barrels from a year earlier and close to the top of the five-year range for the time of year. Significantly, seasonally high inventories have continued to occur despite historically high refinery activity. Refinery runs in the latest four-week period, propelled by the rise in net product exports, were 16.40mmb/d, up 3% on a year ago and the highest level in more than 30 years. Continuing upward pressure on US crude inventories remains a function of the buoyant trend in liquids production.

Exhibit 3: US crude oil inventories



Source: EIA

The seasonal pattern would suggest a rise in crude inventories in the coming weeks as refineries enter the maintenance period and gasoline consumption dips following the end of the summer driving season. We believe during the fourth quarter that US commercial inventories could exceed the May 2014 record of 399.4mm barrels.

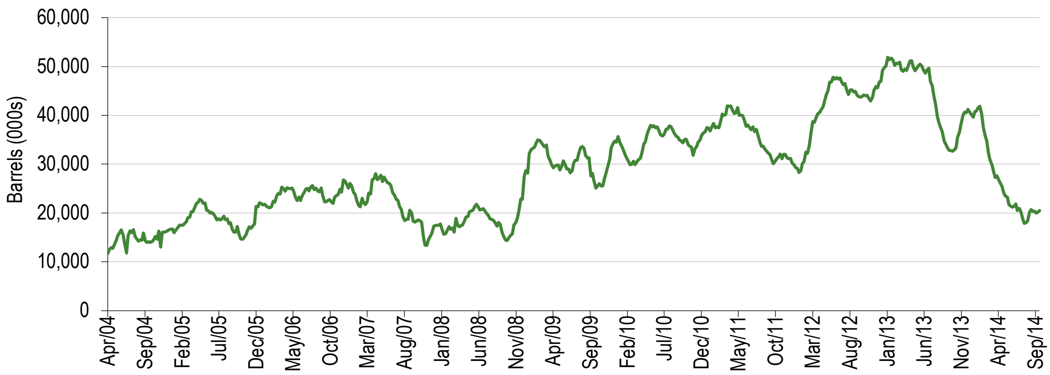
On a days' supply basis, crude inventories are at comfortable levels allowing for seasonality. On 12 September inventories were equivalent to 22.1 days' supply, which was marginally down on the 22.3 days of a year earlier and well within the range that has prevailed since 2000. Including the strategic petroleum reserve, inventories on 12 September were 1053.2mm barrels, equivalent to about 64 days' supply.

Cushing: Inventories could increase in Q4 due to pipeline start-ups

Crude inventories at the Cushing, Oklahoma tank farm, the delivery point for Nymex crude, were on a pronounced downward trend from early 2013 to July 2014. At the recent low on 25 July inventories stood at 17.90mm barrels, down 65% on peak levels. The drop contrasted sharply with the upward trend in the US overall and reflected a combination of pipeline infrastructure developments which relieved the Cushing bottleneck and very high refinery activity. The key developments were the following:

- TransCanada's Cushing Marketlink (the southern section of Keystone) linking Cushing with Houston.
- Sunoco's Permian Express linking the Permian basin with the Gulf.
- Magellan Midstream Partners Longhorn linking the Permian basin with the Gulf Coast. Both the Longhorn and the Permian Express diverted oil that had previously been shipped to Cushing.

Exhibit 4: Cushing crude oil inventories



Source: EIA

Since the recent July low, Cushing inventories have trended moderately higher. As of 12 September they stood at 20.0mm barrels. Helping support inventories of late was the closure due to a fire at CVR's Coffeyville refinery in Kansas during August. At around 20mm barrels Cushing inventories are broadly in line with the levels prevailing between 2005 and 2008 which pre-dated the surge in domestic production. As the EIA has noted, the drop in Cushing inventories in 2013/14 reflected broad market trends rather than any emerging shortage of supply. In many ways the surplus that previously existed at Cushing has now merely been shifted to the Gulf Coast. Inventories here have been at record levels in 2014 and on 12 September were 188.6mm barrels, up 6.4% on a year earlier.

We believe there could be a firming trend in inventories at Cushing in the coming months reflecting the pending opening of two pipelines. The most important is Enbridge's 0.6mmb/d Flanagan South running from Pontiac, Illinois to Cushing which will facilitate the movement of crude sourced from Alberta and North Dakota to the Gulf Coast. The other pending pipeline is the 0.25mmb/d Tallgrass Pony Express pipeline from the Guernsey, Wyoming hub to Cushing. Initially this will transport crude from the Denver-Julesburg and Powder River Basins but in future sources of supply will be diversified assuming the construction of the Double H Pipeline from the Bakken to Guernsey.

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

US gasoline inventories have trended broadly flat in recent months. Based on EIA data for the week ending 12 September inventories were 210.7mm barrels, down 5.3mm barrels or 2.5% on a year earlier and towards the middle of the five-year range for the time of year. On a days' supply basis gasoline inventories are significantly below peak levels in recent years of about 28 days but still look pretty comfortable based on the experience since 2000. For the week ended 12 September the actual reading was 23.5 days against 24.2 days a year earlier.

In analysing refined product inventory trends, it should be noted that given the strength of demand internationally along with what we believe are superior margins on such business, there is no incentive to keep excessively high inventories. US gasoline production has been running at historically high levels of late. In the latest four-week period production was 9.08mmb/d or in line with a year previously.

Distillates: Downward trend possibly bottoming out

The marked downward trend in US distillate inventories between mid-2010 and end 2013 has effectively bottomed out in 2014. Inventories however remain at or slightly below the low end of the five year range for the time of year. Taking the week ending 12 September 2014 inventories stood at 127.8mm barrels, down 2.5% on a year earlier. The latest inventory reading is equivalent to 34.5 days which is in line with a year ago and well above the lows of about 22 days plumbed in the early to mid-2000s. Days' outstanding at about 50 in 2009/10 by contrast, were unusually high and a function of recessionary influences at the time.

We believe strong international demand and attractive crack spreads have been the key factor depressing distillate inventories over the past few years. Effectively, these factors have led to a new normal for distillate inventories and a downward shift in desired inventories. Distillate exports (25% of production) in the latest week are slightly down on a year ago but up 11% on two years earlier.

All petroleum products: Inventories remain historically high

In our view, the acid test concerning the adequacy of petroleum industry inventories is the all-encompassing definition including US commercial crude oil and refined product. Based on EIA data for 12 September, inventories on this basis stood at 1,138.8mm barrels. This is up 2% on a year earlier and is very close to an all-time high.

Argentina: Interesting operational and commercial developments

Argentina is host to the world's largest and most advanced shale/tight reservoir oil/gas development projects outside North America. The projects are located in the Neuquen basin 1,000 to 1,500 km southwest of Buenos Aires in the provinces of La Pampa, Neuquen, Mendoza and Rio Negro. They focus on the Jurassic/Cretaceous age Vaca Muerta formation at about 9,500 ft but also include the deeper Los Molles and the shallower Lower Agrio formations. The Vaca Muerta formation covers a substantial area of 30,000 square kilometres and was estimated by Ryder Scott to contain 23bnboe of recoverable resources. The Los Molles and Agrio formations could provide significant upside so we may be looking at an unconventional recoverable resource base in the Neuquen basin that is similar in scale to the Bakken/Three Forks and Eagle Ford petroleum systems based on the latest industry estimates. Arguably, the key analogue for the Vaca Muerta is the Cretaceous age Eagle Ford. Based on key characteristics such as thickness, porosity, total organic content and reservoir pressure Vaca Muerta compares favourably with the Eagle Ford and indeed other US unconventional plays.

YPF Agrio and Exxon Vaca Muerta discoveries Over the past few months there has been some very interesting exploration and development news concerning the Neuquen basin. A case in point was the announcement in August by state controlled YPF of a discovery in the Agrio formation at the Filo Morado well in southern Mendoza. No details have been revealed but the YPF CEO, Miguel Galuccio, has described the test results as 'very promising'. In the St Jorge basin in Chubut province YPF in May also pointed to a discovery in the D-129 shale formation. Exxon announced in May its first discovery in the Vaca Muerta via an operated project. The Bajo del Choique X-2 well was drilled to 15,000ft and produced 770b/d using a horizontal section. Further appraisal drilling will be required to determine commerciality.

Petronas accord: Financing news of late has been dominated by the $550m accord between YPF and Petronas ($75m YPF and $475m Petronas), the Malaysian national oil company, to develop the La Amarga Chica block northwest of its Loma Campana joint venture with Chevron. The plan is to drill 30 wells over three years. According to YPF, further joint ventures could be announced in the near term with the Chinese state controlled majors, Sinopec and CNOOC.

George Soros doubles his stake in YPF: An announcement was made in August that the legendary investor George Soros had more than doubled his stake in YPF to 3.5%. It should be noted in this context that YPF is by far the largest play on Vaca Muerta. Significantly, other hedge funds such as Perry Capital and Third Point LLC are also reported to have increased their stakes in YPF of late. Clearly, the investments of the hedge funds, including Soros, are a vote of confidence in YPF and the potential of the Vaca Muerta.

New oil and gas regulatory environment: The legislation governing the oil and gas industry in Argentina is being reformed. New legislation replacing the 1967 hydrocarbons law is imminent. This is expected to standardize the regulatory environment across provinces particularly in terms of royalty rates and the auction process for land concessions. Presently, royalties and the auction process vary by province. Shale and offshore concessions will be granted for 35 years. Importantly, companies that invest $250m over a five year period will be exempt from export taxes for up to 20% of output and will also not have to remit all dollar earnings. Historically exploration and development costs have been elevated in Argentina due to import duties on equipment and local content rules. This regime has been partially liberalised with the removal of duty on drilling rigs. A further easing of import restrictions and local content rules is a possibility.

Domestic oil and gas prices have been partially liberalised over the past two years or so. Gas from new discoveries is sold at $7.50/mcf, while the reference price for crude is $70/barrel.

Production is advancing strongly: YPF is pointing to a strong upward trend in Vaca Muerta production from an admittedly low base. According to the company, production was running at 23,200boe/d gross from its key Loma Campana project in the second quarter of 2014. This was up 24.7% on the first quarter and 137% from a year earlier with production split roughly 50:50 between oil and gas. The YPF CEO, has indicated that Loma Campana production has recently risen to 31,000boe/d. Given this we believe unconventional output in total in the Neuquen basin might be around 35,000boe/d presently. Predictions made by the YPF/Chevron Loma Campana joint-venture that Vaca Muerta production could be about 80,000boe/d by 2017 look entirely plausible if not conservative.

Will the debt dispute with the hold-outs derail Vaca Muerta development? At the end of July Argentina was ruled to be in selective default on debt restructured as a result of the earlier default of 2002. The latest 'default' arose not from an unwillingness to make coupon payments but a bizarre judgement by a New York court that the payments could not be paid without firstly repaying holdout bondholders, who had not agreed to the original restructuring, at 100cts on the dollar. Argentina has argued that the holdouts, the best known of which is the New York hedge fund NML and which have been termed as los buitres (the vultures), can't be paid in full without triggering the RUFO clause in the bond contracts. Triggering the RUFO (rights upon future offers) would result in the need to offer the same terms to the owners of the restructured bonds. This would necessitate payments of over $100bn, an amount that Argentina could not finance.

The key question now is, will the dispute between the Argentine government and los buitres and the technical' default' derail Vaca Muerta development? The answer is probably no. Note here YPF is an independent stockmarket-listed entity with 49% of the stock in private hands. It should not be vulnerable to an attack by los buitres on its vital interests. YPF also successfully raised $1bn through a heavily oversubscribed debt issue in New York earlier this year so is far from out of favour with the bond market. Furthermore the business is also comfortably profitable. As far as foreign investors are concerned, we think the key issue will continue to be the perceived attractions of the Vaca Muerta play.

One possible major area of concern to a foreign investor currently is the wide spread between the official exchange rate at 8.40 pesos to the dollar and the parallel or blue rate of approaching 15. Fears of a major devaluation in the peso could in the short term delay transfers of dollars to Argentina. We believe a resolution of the stand-off between the Argentine government and los buitres will either have to await the expiry of the RUFO clause at the end of 2014 or possibly more likely the next Presidential election in October 2015. In all likelihood los buitres will have to accept a great deal less than 100 cts on the dollar. An offer of 30cts is on the table in line with the deal struck with the other creditors in the debt restructurings of 2005 and 2010. Note los buitres acquired the Argentine debt for a few cents on the dollar.

Light crude spreads

WTI-Brent: Narrows sharply

Since the end of 2013 the WTI-Brent discount has narrowed sharply from about $12/barrel to $3.4/barrel. Furthermore, in the six months to September 2014 the spread between the two grades moved in a much tighter range than had been the case over the three prior years. Broadly speaking, we can say that the WTI discount that has prevailed since the third quarter of 2010 has normalised bearing in mind the continuing influx of supply in the US Mid-Continent and transport costs from the Cushing tank farm to the Gulf Coast refinery complexes.

Exhibit 5: WTI-Brent spread

Source: Bloomberg

On a quarterly basis in 2014 the WTI-Brent discount has averaged as follows: Q1 $9.2, Q2 $6.7, Q3 $4.2. The discount in the nine months to September has ranged between $3.4 and $14.9/barrel but since April the range has narrowed to between $3.4 and $8.9/barrel. The narrowing trend in the WTI discount in 2014 has been despite the continuing Mid-continent production build-up and reflected the following:

- The sharp drop in inventories at Cushing, the Nymex pricing point, stemming in large part from developments of the pipeline infrastructure. These have enhanced the flow to the Gulf Coast and re-directed supplies away from Cushing.
- Robust refining activity supported by a solid domestic market and strong export demand.
- The build-up of a supply surplus in the Atlantic basin reflecting lacklustre Western European demand and the sharp drop in US imports from West Africa.
- The greater sensitivity of Brent to the economic slowdown in China.

At just over $3/barrel at the end of September the WTI discount is less than pipeline costs for uncommitted shipments from Cushing to the Gulf Coast of about $4/barrel. Substantial quantities of crude are also shipped by rail from Cushing at a cost closer to $10/barrel. On a blended basis average transportation costs between Cushing and the Gulf Coast might therefore be around

$7/barrel which is well above the current WTI discount. To facilitate the flow of oil from Cushing to the Gulf Coast we would normally expect the discount to be at least $6-7/barrel. In practice we think it may be necessary to add another $2-3/barrel given the discount to Brent that has opened up for Gulf-sourced light crude grades such as LLS. This would suggest a range of $6-10/barrel. Geopolitical issues threatening to constrain supplies outside the US could lead to a considerably higher upper level from time to time as could pipeline outages. Conversely, other things being equal, a large scale resumption of Libyan exports would tend to compress the WTI discount.

Over the balance of 2014 we would expect the WTI-Brent spread to move broadly in line with the pattern of the past six months. This in turn is not dissimilar to our estimate of a viable range. Specifically we look for a fourth quarter WTI discount averaging $6.0/barrel. The widening compared with end September reflects in part the transportation cost issue and in part the expectation that inventories at Cushing will increase over the balance of the year due to pipeline start-ups that will increase the flow of oil into the tank farm. The implied average WTI discount for 2014 as a whole of $6.7/barrel compares with $10.8/barrel in 2013 and an earlier forecast of $9.1/barrel. For 2015 we are looking for an average WTI discount of $6.2/barrel or similar to the prior year.

Exhibit 6: WTI 2009-15 quarterly prices ($/barrel)

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	62.0
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013	94.3	94.1	105.8	97.6	98.0
2014e	98.7	103.1	97.6	89.5	97.3
2015e	89.0	88.0	89.0	89.0	88.8

Source: Bloomberg, Edison Investment Research. Note: Q1, Q2 and Q314 are actuals.

Exhibit 7: Brent 2009-15 quarterly prices ($/barrel)

	Q1	Q2	Q3	Q4	Average
2009	45.1	59.4	68.4	75.0	62.0
2010	76.8	78.6	76.4	86.9	79.7
2011	104.9	116.8	109.1	109.3	110.0
2012	118.7	108.7	109.8	110.9	112.0
2013	112.8	102.9	110.0	109.4	108.8
2014e	107.9	109.8	102.2	95.5	103.9
2015e	95.5	95.0	94.5	95.0	95.0

Source: Bloomberg, Edison Investment Research. Note: Q1, Q2 and Q314 are actuals.

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 which broadly reflects pipeline costs. At the end of 2013 the discount at $2.50/barrel was slightly above the historical norm. During 2014 the discount has been on a widening trend and has averaged $8.1/barrel in the year-to-date end September. The Midland discount reached a virtually unprecedented $21.0/barrel on 19 August resulting in an absolute price level of a depressed $73.5/barrel. Since this date the discount has narrowed markedly but at $8/barrel in late September was still well above average.

Driving the widening trend in the Midland discount in 2014 has been buoyant production in the Permian Basin and lags in expanding takeaway capacity. Effectively the discount has had to widen to provide an incentive to ship either to Cushing or the Gulf Coast. Given the planned opening of Magellan Midstream Partner’s 0.3mmb/d Bridgetex Pipeline at the end of September, the Midland discount could narrow in the coming months. The pipeline runs from Colorado City in West Texas to Houston.

The clear beneficiaries of the historically wide Midland discount in 2014 have been refineries located in northern and western Texas and New Mexico. The key refining groups concerned are Western Refining, Delek Holdings, Alon USA Partners, Phillips 66 and Valero Energy.

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

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

Exhibit 8: Bakken economics

	$/barrel
Gross realisations 1 October 2014	86
Royalties	-16
Net realisations	70
Lifting and site operating costs	-12
Severance costs	-7
G&A	-5
Transport to Clearbrook, Mn	-5
EBITDA	41
Drilling/completion costs	-15
EBIT	26
Assumptions	
Royalty rate 18.5%	
Severance rate 8%	
Drilling/completion costs $8m/well, EUR 550,000 barrels	
No allowance for natural gas	

Source: Edison Investment Research and industry presentations

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

After the acute volatility of 2012 and 2013 when at times the Bakken discount widened to over $15/barrel or even $20/barrel, the trend in 2014 has followed a more subdued course. Through end September Bakken grade oil has traded at a discount to WTI averaging $5/barrel so far in 2014. During the course of the year the range for the Bakken discount to WTI was $8 to $2/barrel while in late September it was $5.3/barrel. The implied discount to Brent in late September of $7.2/barrel was clearly insufficient to cover railage to the seaboards. This applies particularly bearing in mind the discounts applying on the Gulf Coast for locally sourced crude. To be competitive with LLS, for example, Bakken would need to sell at a discount to Brent of about $14/barrel (railage of $12 plus the LLS discount to Brent of $2). To be competitive on the Gulf Coast the Bakken discount to WTI might need to be in the region of $10/barrel. The precise amount will depend, of course, on the discount of WTI to LLS.

Refinery capacity expansion: The sizeable discounts required to sell Bakken crude on the coasts clearly depresses producer economics. One answer to the problem would be to sell more crude into the upper Midwest and mountain state refineries. This strategy, however, is constrained by high refinery utilisation rates. Some modest relief is at hand given actual and planned capacity expansion in North Dakota. Five refinery projects here are in the pipeline. The first relates to the construction of the Dakota Prairie refinery at Dickinson in the west of the state. This is a joint venture between MDU Resources and Calumet Specialty Products and relates to a relatively small 20,000b/d topping facility focusing on distillates and naphtha. Start-up is expected in the fourth quarter of 2014. Given the roughly two year construction lead time further start-ups are possible by 2016.

Refinery expansion in North Dakota is being driven by surging demand for diesel and other distillates in the region as a direct result of the petroleum industry development boom. Industry sources suggest that the demand for diesel in the state currently is about 0.14b/d which is twice the capacity of the Mandan refinery. Given the buoyant energy driven economy in the northern Great Plains, further refinery expansion projects are a very real possibility in both the upper Midwest and the mountain states.

Bakken economics: Whiting suggests 70% of acreage still worth drilling at $70/barrel

Given the significant downward trend in oil prices over the past three months or so Bakken economics has clearly deteriorated of late. Based, however, on late September 2014 prices of around $88/barrel, we believe typical Bakken development projects are still comfortably profitable on a fully accounted basis as indicated below. Using our model prices would have to fall to about $65/barrel to become truly marginal after allowing for the cost of capital. Of course, much depends on the assumptions concerning well EUR's and drilling/completion costs. It should be noted however that completed well costs (CWCs) are tending to fall reflecting operational efficiencies and such factors as well down-spacing (more wells per acre) and multi-well pad drilling. Continental Resources, for example, is aiming to reduce Bakken CWCs by $0.5m to $7.5m between 2013 and 2014.

Interestingly, James Volker the CEO of Whiting Petroleum (the largest producer in the Bakken following the acquisition of Kodiak) has suggested that two-thirds of its acreage, including recently acquired Kodiak, is 'still worth' drilling at oil prices of $70/barrel.

Syncrude-WTI: Close to parity with WTI

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

As has been the case with Bakken grade oil, the Syncrude-WTI spread has been much less volatile in 2014 than in recent years. During 2014 Syncrude has traded between a premium of $4.5/barrel and a discount of $5.0/barrel. The high point was reached in April and probably reflected an outage at one of Syncrude Canada's two coker facilities for unplanned maintenance. In late September Syncrude was trading at a discount of $1.0/barrel. On average in the year-to-date September Syncrude has traded at a marginal $0.6/barrel discount to WTI. Abstracting from major plant outages or harsh weather conditions,we would expect Syncrude prices to continue to trade close to WTI over the balance of 2014.

In late September Syncrude was trading in absolute terms at about $90/barrel. Although well down on the peak this year of $108.6/barrel Syncrude producers probably remain comfortably profitable based on Canadian Syncrude's operating cost (excludes depreciation) guidance for 2014 of C$45.73/barrel or US$41.6/barrel.

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

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

The WCS discount to WTI has narrowed sharply between 2013 and 2014. In the former year the discount averaged $24.5/barrel and in November plumbed a hefty $42/barrel resulting in an absolute price not much above $50/barrel. After narrowing markedly through early 2014 to about $20/barrel the WCS discount trended broad flat over the subsequent six months or so. Following a widening to about $24/barrel in July the discount has again narrowed over the past two months and in late September was down to about $13/barrel, the narrowest discount in about 15 months. The absolute price was $76.9/barrel, which represented an $7.3/barrel discount to the comparable Mexico-sourced Maya crude, the key benchmark. Based on Bloomberg data the implied price for bitumen in late September was $70.4/barrel.

We believe the narrowing of the WCS discount in 2014 is symptomatic of structural changes taking place in the market for Albertan heavy crude along with takeaway capacity expansion. The key factors are as follows:

- The conversion of BP's Whiting, Indiana refinery (the largest inland refinery in the US) to operate on a diet of mainly heavy feedstock sourced from Alberta. Following the completion of the Whiting upgrade last year it now uses 80% heavy feedstock rather than 20% previously. The impact of the changeover is about 0.3mmb/d.
- Rapid expansion of Alberta rail takeaway capacity. Until recently such capacity was virtually zero but in the second quarter of 2014 was about 0.55b/d and by early 2015 could be 1mmb/d. Further expansion is planned which would take capacity to 1.5mmb/d by end 2015. Significantly, the first shipment of WCS was made in September by rail from Alberta to Suncor's newly constructed terminal near Montreal. The oil was scheduled for export to Italy. Industry sources have suggested that railage from Alberta to Montreal costs about $12/barrel, although this probably assumes that the shipper owns the rail cars. Costs otherwise might be closer to $20/barrel.

Pipeline capacity additions: In October 2014 Alberta will be connected with Montreal for the first time. This will follow completion of Enbridge's Line9B reversal from North Westover in Ontario, the terminus currently for the Main Line pipeline from Alberta. The reversed Line9B will have a capacity of 0.3mmb/d and should enable the Suncor and Valero refineries at Montreal and Quebec City respectively to be largely independent of imported feedstock. Potentially it will also provide a high volume eastern export route for WCS.

Pipeline capacity is also being expanded to the south with the pending start-up of the 0.6mmb/d Flanagan South facility from Pontiac, Illinois to Cushing. In addition, Enbridge is contemplating building a rail terminal at Pontiac capable of taking two trains a day from Alberta. This could be in service by mid-2016 and would significantly relieve the pipeline capacity bottleneck in southern Alberta. Pipeline capacity additions, plus rapidly expanding rail takeaway capacity probably suggest that construction of the Keystone XL pipeline from Alberta to Cushing via the direct route is less urgent than might have been the case previously.

An expansion of pipeline takeaway capacity from Alberta to the west remains on the cards, although nothing imminent appears on this front. Enbridge's Northern Gateway project from Bruderheim north of Edmonton to Kitimat, British Columbia, was given statutory approval in June but an agreement with the First Nations has yet to be struck. The target of a 2018 start-up is no longer feasible. Indeed, Northern Gateway as currently planned might never be constructed according to industry insiders. In the short term, at least, a viable alternative might be to expand Kinder Morgan's Trans Mountain Pipeline from Edmonton to Vancouver and Puget Sound in Washington State. Kinder Morgan has in fact suggested an expansion from 0.3mmb/d to 0.89mmb/d.

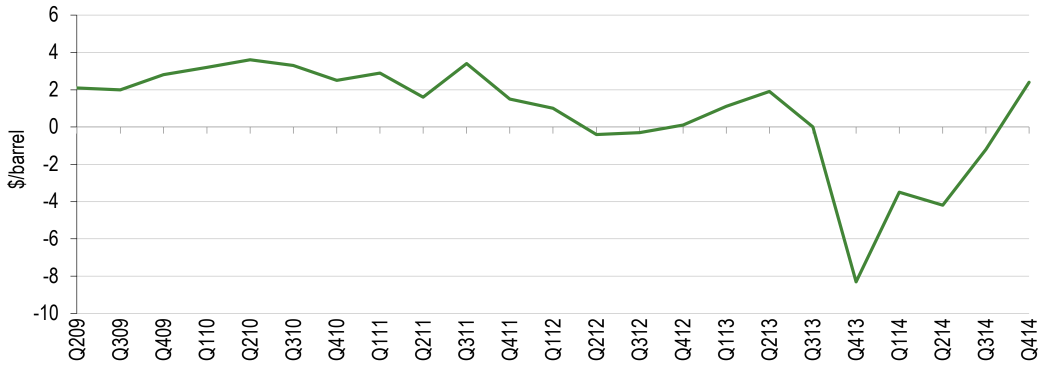
Economics According to the Canadian Energy Research Institute (CERI), the fully accounted costs, including a 10% return on investment, for producing a barrel of bitumen from the oil sands are $65 and $46 using the mining and in-situ production routes respectively. Based on the Bloomberg late September quote of $70.4/barrel, bitumen (ex-Edmonton) would look to be moderately profitable currently on a fully accounted basis.

In many ways the key drawback to Alberta oil sands sourced bitumen is high pipeline costs stemming from long distances to end markets, high viscosity and the need to add costly dilutants. Pipeline costs for light oil from Alberta to the Gulf Coast are about $10/barrel but for bitumen could be closer to $20/barrel. This would imply a delivered price to the Gulf Coast of about $90/barrel (based on an ex Edmonton price of $70/barrel) which is marginally above the late September Maya price of about $87/barrel. Note also that bitumen is lower grade refinery feedstock than Maya. Looking at WCS the economics could be somewhat more favourable given the likelihood of lower pipeline costs stemming from lower dilutant requirements. Assuming the late September ex-Edmonton WCS price of $76/barrel we could be looking at approximate parity with Maya after allowing for shipment to the Gulf Coast.

LLS-Brent: LLS swings back to a premium in early October

The discount between LLS, the Gulf-based light crude benchmark and Brent that emerged strongly in the second half of 2013 has subsequently narrowed sharply. During the most recent quarter the discount averaged $1.3/barrel well down from the $8.3/barrel of the fourth quarter of 2013 and also from the $3.5 and $4.2 of the first and second quarters of 2014. By late September LLS was in fact trading at approximate parity with Brent or even at times a slight premium. The narrowing of the LLS discount to Brent during the course of 2014 is in tune with a similar trend in WTI. Unlike WTI, the LLS discount can't be attributed to a drop inventories given that along the Gulf Coast they are at near record levels. Rather, the narrowing LLS discount appears to reflect very high Gulf Coast refinery activity and the weak Brent fundamentals referred to earlier

Exhibit 9: LLS-Brent spread



Source: Bloomberg, Edison Investment Research

The key question now is does the sharp narrowing of the earlier discount to Brent represent a slightly perverse short term phenomenon or is it the beginning of a longer term trend with LLS returning to its historical modest premium. Given the scale of the Gulf Coast inventories and the likely continuing influx of supply from new pipeline and rail connections, we would expect to see a return to a discount to Brent in due course. As indicated in earlier reports we think this could be $2-3/barrel. The caveats are that the export embargo remains intact and that Brent fundamentals don't deteriorate greatly in the coming months.

Brent-Dubai: Historically narrow Dubai discount

Dubai Fateh is a Gulf-sourced light but relatively sour crude popular with Far Eastern refineries. After trading at a discount to Brent of around $3.5/barrel in the first and second quarters of 2014, a pronounced narrowing took place in the third quarter to $0.7/barrel. In late September the discount remained at about $0.7 which was around a four-year low. The narrowing in the Dubai discount appears to mainly reflect the supply overhang for light crudes in Asia, depressed refining margins and the continuing closure of the Kirkuk to Ceyhan pipeline. The latter factor is probably keeping supplies tight of sour compared with light grades. Significantly, Urals another sour grade, has recently swung from discount to a modest premium to Brent.

Tapis-Dubai: Tapis premium narrows sharply in the third quarter

Tapis is a low-sulphur Malaysia-sourced light crude popular with refineries in the Far East. The Tapis-Dubai spread is one of the key sweet-sour crude oil price relationships. Reflecting its premium specification, Tapis typically trades at a significant premium of $7-10/barrel. During the first and second quarters of 2014 the premium averaging $9.5/barrel was in line with the top end of the historical range and largely unchanged from the fourth quarter of 2013. During the third quarter however the Tapis premium to Brent narrowed to an unusually low $4.7/barrel. By the end of September the Tapis premium had narrowed a little further to $4.3/barrel. The narrowing trend for Tapis reflects similar factors to Brent. Given the structural shift in Atlantic light crude fundamentals post the build-up of US supplies, it is possible that the Tapis premium to sour grades is also in secular decline.

US Gulf heavy crude spreads: Widening WTS discount, Permian supply issues

LLS-Mars: Mars is a medium-sour grade sourced from the Gulf of Mexico that normally trades at a discount to LLS of $2-6/barrel and in 2013 averaged $5.1/barrel. The Mars discount has narrowed in 2014 but has remained within the historical range. Averages for the first, second and third quarters have been $3.5, $4.8 and $3.7/barrel respectively. Weighing on the discount in 2014 was the abundance of light crude along the Gulf Coast. The expected continuing build-up of light crude supply along the Gulf Coast could portend a longer term narrowing of the Mars discount. It should be remembered here that many Gulf Coast refineries are currently configured for heavy-sour feedstock.

LLS-Maya: Maya is a Mexico-sourced heavy-sour grade with a specification similar to WCS. It normally trades at a discount to LLS in the range of $5-12/barrel. The Maya discount widened significantly between the fourth quarter of 2013 and the first quarter of 2014 from $11.6 to $15.1/barrel but narrowed to $9.9/barrel in the second quarter and remained at about this level in the subsequent quarter. In late September the Maya discount had narrowed to about $9/barrel, although this remained within the historical range. As in the case of Mars, we believe the compression of the Maya discount in recent months reflects the light crude supply build-up along the Gulf Coast.

WTS-WTI: West Texas Sour (WTS) is a US inland medium-sour grade with a specification similar to Mars and a delivery point of Midland, West Texas. Historically, WTS has generally traded at a discount to WTI of $1-3/barrel and in 2013 averaged $2.6/barrel. The discount has been significantly wider in 2014 at $5.5, $7.2 and $8.8 in the first, second and third quarters of 2014 respectively. In late September WTS was trading at a discount of $8.3/barrel to WTI. The widening of the discount in 2014 appears to reflect mainly burgeoning supplies in the Permian Basin and a lag in installing takeaway capacity. Contributory factors may also have been a release of sour crude from the strategic reserve in March and an outage in June due to a fire at Valero's Mckee refinery in northwest Texas. The anticipated start-up of the new Bridgetex pipeline in the coming weeks could result in a narrowing of the WTS discount.

Forward curves: Brent curve moves into contango, WTI backwardation lessens

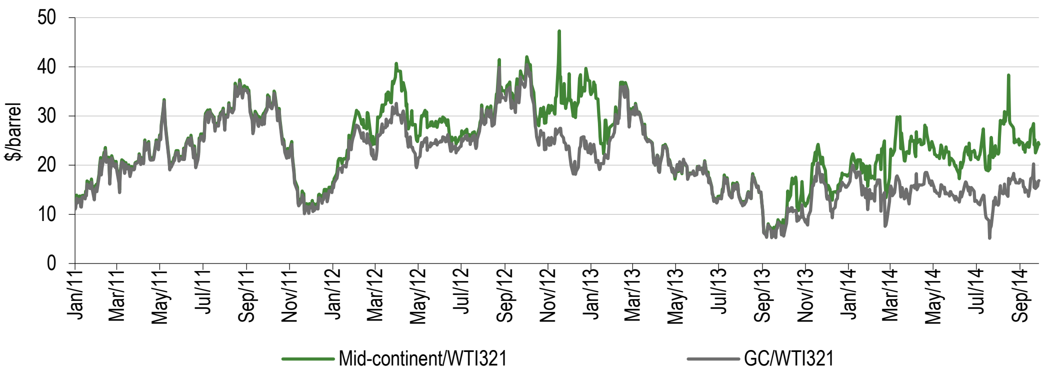
In recent months the forward curve for Brent has switched from a longstanding backwardation (near term prices higher than for the forward dates) to a pronounced contango (near term prices lower than for the forward dates). As of early October 2014 the curve starts at $94.6/barrel for November deliveries and then climbs over the following 12 months to a peak of $98.0/barrel. The curve then dips steeply through late 2019 to about $93.5/barrel before levelling off over the following two years terminating at just over $93.0 in November 2021. Brent's switch from backwardation to contango is consistent with the clear signs of a growing supply surplus in the Atlantic Basin.

Contrasting with Brent, WTI has now been in backwardation for more than a year. The degree of backwardation is however considerably less pronounced than in earlier months. After commencing at $91.4/barrel for November deliveries, the WTI forward curve dips significantly over the next year or so to $85.7/barrel. Subsequently it flattens and terminates in December 2022 at $85.1/barrel. The implied WTI discounts are $3.2/barrel in November 2014, $10.7/barrel in November 2015, $10.3/barrel in November 2016 and $10.1/barrel in November 2017. WTI's continuing backwardation, with rapidly growing production in the Mid-Continent and near record inventories along the Gulf Coast, is arguably counterintuitive given that the phenomenon is normally associated with tight supplies. The obvious answer to the apparent conundrum is the sharp drop in inventories at the Nymex pricing point of Cushing, although there is no indication that this has been involuntary or represents a spot shortage. Another less obvious possibility is that the backwardation is being driven by hedging as operators, under pressure from lenders, attempt to reduce risk by locking in futures prices through derivative instruments. This is possibly increasing supply and reducing prices in the out years. There is a possibility that the hedging tendency could become more pronounced if spot WTI prices should weaken further.

Refinery crack spreads

Gulf Coast spreads US Gulf Coast refinery crack spreads based on Cushing sourced WTI feedstock have trended flat in 2014 at a level close to the long term average. Taking, for example, the Gulf Coast/WTI 321 (GC/WTIC) spread (the margin before refining costs on converting three barrels of WTI into two barrels of gasoline and one of diesel) the quarterly sequence in 2014 has been Q1$14.9/barrel, Q2 $15.2/barrel and Q3 $14.0/barrel. In late September the GC/WTIC spread was around $15.5/barrel after having been as high as $20.5/barrel earlier in September. On a year-to-date basis the GC/WTIC spread has averaged $14.7/barrel, down 25% on the comparable period in 2013. It should be noted, however, that the spreads so far in 2014 are well above the $12.2/barrel recorded in the third and fourth quarters of 2013.

Exhibit 10: Recent trends in Gulf Coast and mid-continent crack spreads



Source: Bloomberg

Recently recorded spreads are, of course, well below peak levels of $30 to$40/barrel in the period 2011 to the first half of 2013. These were however virtually unprecedented historically. The average GC/WTI321C spread in the five and ten years to 2013 was $16.1and $12.9/barrel respectively. Note also that the Gulf Coast spreads still compare very favourably with other parts of the world. The NWE/Brent 321 (Northwest Europe) spread, for example, has averaged a modest $10.4/barrel in 2014, although during the course of the year it has trended higher, rising from a low of $5-6/barrel to around $13/barrel in late September.

The downward pressure on Gulf Coast spreads between 2013 and 2014 has been largely driven by a drop in refined product prices. On a year-to-date basis regular gasoline and diesel have both fallen about 7% from 2013 while WTI has risen by just under 2%. Interestingly, diesel has been particularly weak of late falling by about 14% from the late June peak. Gulf Coast diesel prices in late September 2014 were in fact approaching a two-year low. Gasoline prices, by comparison, have declined by about 10% from the June high and in recent weeks have shown signs of rebounding reflecting optimism concerning the economy. We believe softness in product prices is a reflection of high rates of refinery activity and less than robust demand.

Mid-Continent spreads: Mid-Continent refining spreads remain significantly above those on the Gulf Coast and are impressive by world standards. Furthermore, contrasting with the Gulf Coast, the Mid-Continent spread has trended higher during the course of 2014. The quarterly sequence for the Mid-Continent/WTI 321 spread has been as follows: Q1 $23.3/barrel, Q2 $25.3/barrel and Q3 $27.3/barrel. In late September the spread was around $26/barrel. So far in 2014 the high has been $40.6/barrel on 19 August when the WTI Midland price plunged. Looking at the year-to-date the Mid-Continent spread has averaged $25.3/barrel which is in line with a year earlier.

Wider spreads in the Mid-Continent than the Gulf Coast mainly reflects lower cost feedstock reflecting the sizeable discount of WTI Midland to WTI Cushing. The upward trend in the Mid-Continent crack in 2014 has been driven by the pronounced fall in WTI Midland feedstock costs.

Crude oil price outlook: Possible price floor $80-85/barrel

Backdrop: We continue to believe that the near- to medium-term outlook for oil prices is bearish. In our view the key factor is the likelihood that buoyant growth in non-OPEC controlled production will comfortably outpace global demand over at least the next two years and quite possibly the balance of the decade. Near term, production growth will continue to be led by the US and Canada but post 2015 Brazil should make a growing contribution as the massive, offshore pre-salt developments come to fruition. Demand growth, we believe, will continue to slow reflecting a combination of technological advances, particularly in the transportation sector, leading to radical improvements in fuel efficiency and political initiatives designed to reduce the carbon intensity of the economy. In future, based on current expectations for the world economy demand growth is unlikely to greatly exceed 1%pa. In this context, note that surging growth in China is history and that hefty subsidies in the developing world will probably be scaled back in the coming years for budgetary and possibly environmental reasons.

Near-term OPEC might try to control the market but we believe it will find it increasingly difficult to do so. This reflects the sheer scale of the potential non-OPEC influx and the anticipated desire of at least three major members to boost output near to medium term. The three are Iraq, Iran and Libya. Note, Iraq is not bound by quota restrictions while the other two are operating well below their allotted quotas. Clearly, there are uncertainties about how quickly and how much Iraq, Iran and Libya will be able to boost output but even over a two year time frame we think it unlikely that the three combined will not be producing significantly more than in 2014. All told, we believe the next few years could resemble the situation post the mid-1980s when OPEC lost control of the market following a surge in supply in Alaska and the North Sea.

A particularly interesting development of late in oil market circles with bearish price implications relates to the apparent evaporation of geopolitical concerns. This is despite some major developments on the world scene such as the Ukraine crisis and IS's play for real estate in Iraq and Syria that would normally be considered as supportive for oil prices. For some time of course the frequent surfacing of geopolitical concerns has tended to obscure weakening fundamentals. Generally the concerns have proven to be fallacious or at best overblown. It could be that the geopolitical premium in oil prices will diminish in importance over time.

Potential downside: Arguably, the key question now concerning the oil market is the downside risk. In principle prices can drop to short-run cash marginal cost if fundamentals deteriorate sufficiently. This could be in the region of $45/barrel (excludes SG&A and capital costs but includes royalties and severance) in the tight reservoir plays of North America but perhaps only $5/barrel in OPEC in the Middle East and North Africa. Tight reservoir plays however suffer from high rates of depletion and require heavy investment to maintain production levels. In practice then, any prolonged period with prices below fully accounted costs, including an allowance for the return on capital, would probably result in a rapid decline in drilling activity and a self-correcting upturn in prices, as indeed OPEC has postulated. This might suggest a price floor equivalent to fully accounted costs on tight reservoir plays. As indicated earlier, this could be in the region of $65-70/barrel for the more productive plays but quite possibly somewhat higher on average. We suspect that if light oil prices were to drop below $75 to $80/barrel this would be the trigger point for a significant cutback in North American drilling activity. Note for oil sand projects the issue of depletion does not apply in the same way as for tight reservoir plays. Once facilities are installed production will therefore tend to be maintained virtually regardless of any conceivable price. A major drop in oil prices would of course ultimately curtail development activity.

Although we believe that OPEC will have difficulty in holding the line on prices over the next few years, it will probably retain some residual influence over the marketplace. This together with the above might suggest a price floor near to medium term of $80-85/barrel. The caveat is that recessionary conditions globally are avoided.

Forecasts – reducing our price forecasts: Given the bearish market backdrop for light crude in the Atlantic Basin combined with considerable carryover weakness from the third quarter, we are downgrading our average Brent forecast for 2014 from $105.4/barrel to $103.9/barrel. It should be noted that the average for 2014 has been buoyed by the relatively buoyant first and second quarters when Brent averaged $107.9/barrel and $109.8/barrel respectively. The latter exceeded our forecast of $107.0/barrel while the third quarter actual of $102.5/barrel was below our forecast of $104.0/barrel. Our new forecast for the fourth quarter is $95.5/barrel which compares with $102.5/barrel previously. A key wildcard for the fourth quarter of 2014 concerns the outcome of the talks between the world's major powers and Iran over its nuclear programme. An agreement by the 24 November cut-off date could be highly bearish given the implications for a full resumption of Iran's crude oil exports.

For 2015 we are downgrading our Brent forecast from an average of $99.5/barrel to $95.0/barrel. This reflects greater carryover weakness than previously expected along with the bearish fundamentals mentioned earlier. Inevitably there are risks to the forecast on the upside and probably to a lesser extent on the downside in 2015. As far as the upside is concerned the key ones are supply related and mainly revolve around geopolitical shocks that genuinely impact production and OPEC's output policy stance . On the downside we see the key risk for Brent in 2015 as being a strong simultaneous upturn in production and exports from Iraq, Iran and Libya and a complete loss of control of the market by OPEC. Another possibility is that the world economy grows by more than currently expected resulting in stronger demand. Oil demand however is becoming less leveraged to economic growth.

Our 2014 WTI forecast is actually being raised from earlier levels. We are now looking for WTI to average $97.3/barrels against $96.3/barrel previously. The key issue here is that the trend in the second and third quarters was considerably stronger than we expected notwithstanding the price decline since June. The actual outcomes were $103.1 and $97.6/barrel respectively against the $98.0 and $95.0 forecast. For the fourth quarter we are now looking for $89.5/barrel which is well down on the previous forecast of $93.5/barrel. The fourth quarter downgrade reflects considerably greater than expected negative carryover from the third quarter, continuing production gains and the expectation that inventories will increase in the coming months at Cushing. Our WTI forecast for 2015 has been downgraded from $91.0/barrel to $88.8/barrel reflecting similar factors to Brent. WTI forecasts for 2014 and 2015 reflect discounts to Brent of $6.7 and $6.2/barrel respectively both of which are narrower than 2013's $10.8/barrel. The key issues for WTI over the next 15 months or so are the robustness of the local production trend, the inventory position at Cushing and the strength of the US economy. The key upside risk for WTI would probably be a pronounced slowing in production growth.

Exhibit 11: 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	97.3	88.8
Brent	54.5	65.4	72.7	97.7	62.0	79.7	110.0	112.0	108.8	103.9	95.0

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

US natural gas market

Production and net imports

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

Production: US natural gas production has shown a pronounced upward trend in 2014 despite continuing subdued dry gas drilling activity. Based on EIA data, marketed production in the six months to June 2014 came in at 15.61 tcf, up 5.2% on a year earlier while production in June itself of 2.61 tcf was 6.9% higher than a year previously. This was a new monthly record. Compared with the second half of 2013, marketed production in the first half of 2014 was up by 3.5%. According to the Denver-based consultancy Bentek Energy, upward momentum remained strong in the third quarter. Dry production was apparently up 7.6% year-on-year in the week ending 24 September.

US natural gas production in 2014 has continued to be driven by development activity and efficiency gains in prolific new dry gas shale plays such as the Marcellus and Utica plus by-product gains stemming from shale oil plays, notably the Bakken and Eagle Ford. The explanation to the apparent conundrum of strongly rising output and subdued dry gas drilling activity can be attributed in part to by-product production in shale oil plays, in part to major efficiency gains in drilling and well completion and in part very high well productivity in the Marcellus. Indicative of the productivity gains in the Marcellus, a recent EIA drilling report shows new-well output per rig rising from 1,200mcf/d in 2010 to about 8,000mcf/d in 2014. Over the past year the gain has been about 14% on this criterion.

Overall, shale plays now contribute about 53% of US marketed gas output which in June was running at 70.2bcf/d. The Marcellus formation of Pennsylvania and West Virginia is by far the largest contributor with estimated production in September of 15.9bcf/d according to the EIA. Compared with a year earlier this is up 57%. The Marcellus is now comfortably the largest source of gas in the US and could account for 25% of overall production by year end. In fact, the Marcellus is vying for the world's number one position as a source of gas. Remember here that Marcellus production only started to gather pace in 2010.

Another strong performer among the shale play is the Utica formation. This lies beneath the Marcellus in Pennsylvania and Ohio but so far has been mainly drilled in the east of the latter state where the formation occurs at shallower depths. According to the EIA, dry Utica dry gas production in August was 1.17bcf/d, 3X the level of a year earlier. The EIA is looking for production in September of 1.35bcf/d which implies the Utica now accounts for about 2% of US gas production. Production in the Utica only started in earnest in 2012.

Importantly, there was some very exciting exploration news concerning the Utica play on 24 September. This centred on an announcement by Houston-based Magnum Hunter Resources concerning its Stewart Winland 1300U well in Tyler County, West Virginia. The well had an initial production rate of a highly impressive 46.5mmcf/d or 7,750 boe/d. According to Magnum Hunter, it is one of the highest gas flow rates ever to have been reported for a shale play in the US. Significantly, the Stewart Winland well is the most south easterly to have been drilled in the Utica play and could pave the way for a major new area to be developed. All the evidence concerning the Utica is pointing to another world-class shale analogous to the Marcellus. Indeed, Magnum Hunter is suggesting that the Utica is 'potentially the best shale play in the US'.

Elsewhere in the shale sector, robust natural gas production trends have been reported in the year-to-date for the Bakken, Eagle Ford, Woodford and a group of smaller plays which the EIA has described as rest of USA. This residual grouping however is sizeable with production in August of 4.38bcf/d (about the same size as the Barnet play in Texas), up 32% on a year earlier. Overall, the shale plays showed an 18% year-on-year gain in production in August 2014. As has been the case for some time, rapid growth in the shale zones has been partially offset by declines in production in several of the more mature producing provinces. This is reflected by the year-on-year declines in the year-to-date June 2014 of 12% in the Gulf of Mexico, 6% in Wyoming and most significantly perhaps, 20% in Louisiana.

Net imports: Historically the US has had a net import balance in natural gas mainly reflecting sizeable pipeline imports from Canada. In recent years net gas imports have fallen sharply reflecting both rising exports to Canada and Mexico and falling imports from the former. Between 2009 and 2013 the balance narrowed by 51% to 3.59bcfb/d (marketed production averaged 70.2bcf/d in 2013). The underlying drivers behind the narrowing have been the surge in the availability of gas over the past ten years, courtesy of intensive shale development activity and strong demand growth in Mexico.

In the first six months of 2014 the net import balance continued to narrow but at a considerably slower pace than in recent years. For the latest six-month period it averaged 3.34bcf/d, down 1.9% on a year previously. Interestingly, pipeline imports and exports both fell in the six months to June 2014. Year-on-year, the former were down 3.5% while the latter were off 7.5%. The drop in imports and exports essentially reflected movements from and to Canada. Meanwhile, exports to Mexico in the six months to June continued to rise and were up 3.8% on a year earlier at 949mmcf/d. Trends in natural gas imports and exports were distorted early in 2014 due to harsh weather conditions which depressed pipeline exports to Canada and Mexico and at the time sucked in imports from Canada.

We would expect the US net import gas balance to resume a more pronounced narrowing tendency in the second half of 2014 and in 2015. This stems from both the strong production trend and Mexican demand growth. Mexico's demand is growing at over 5%pa according to the national oil company Pemex driven by buoyant industrial activity and power generation needs. Significantly the production trend in Mexico is flat. Note burgeoning supplies are available from Texas at prices close to US levels of $4/mmBtu and considerably under the international prices for LNG of $15-16/mmBtu.

The 2bcf/d Agua Dulce Pipeline from the hub of the same name near Corpus Christi to the Mexican border should be in operation by end 2014. Ultimately the Agua Dulce Pipeline will connect with the Los Ramones Pipeline that will transport gas to Monterrey and Aguacalientes state in north-central Mexico (one of Mexico's main business hubs). The EIA is looking for the US net import balance to average 3.32bcf/d and 2.56bcf/d in 2014 and 2015 respectively.

Post 2015 large scale US exports of LNG are scheduled to come on-stream. The first project will be Houston-based Cheniere Energy's Sabine Pass facility in Louisiana which is planned for start-up in late 2015. This will have processing capacity for 3bcf/d or about 4% of current US natural gas production. The seven LNG projects already approved will have processing capacity for about 10bcf/d, including projects such as Magnolia LNG (being developed by Liquefied Natural Gas Ltd LNG:AU) which will have a capacity of 8mtpa across four trains. We caution that many projects being planned will not continue to full construction, but the uptick in interest in both industry and financial markets is notable.

Outlook: Production trend stronger than previously expected

Until recently the growth in US natural gas production was expected to be severely constrained by subdued drilling activity. Growth now looks like being more robust near to medium term than seemed likely until recently. The key factors here are as follows:

- Advances in drilling and completion techniques that are cutting well completion times, boosting well productivity and lowering costs.
- Rapid growth in by-product production stemming from shale oil development activity.
- High-productivity well development in the Marcellus and Utica formations.

The EIA is now forecasting US production gains of 6.2% to 70.72bcf/d in 2014 and 2.5% to 72.46bcf/d in 2015. This compares with forecast growth of 3.0% and 2.5% earlier in the year.

Consumption

Recent trends

US natural gas consumption was buoyant in the first quarter of 2014. This was driven by harsh weather conditions across a wide swathe of the country which boosted heating needs. For the quarter consumption was up 7.4% to 94.7bcf/d on a year earlier. Year-on-year growth slowed to 1.3% in the second quarter as weather conditions returned to normal seasonally. For the first half of 2014 averaged 77.5bcf/d, 4.9% above 2013.

Not surprisingly, consumption growth in the first half was driven by the residential and commercial segments (about 50% of households use gas for space heating) with gains of 8.9% and 10.2% respectively. Industrial users also lifted consumption by 4.3% but power generation use, normally the largest market for gas, slipped by 0.4%. In terms of the former, demand has been supported by reasonably buoyant industrial activity. Power generation demand however has continued to be adversely impacted by deteriorating competiveness vis-à-vis coal. According to the EIA, the natural gas power station burn rate dropped from 26.1% to 25.1% between the first halves of 2013 and 2014. This contrasted with a gain in the coal burn rate from 39.0% to 40.1%. The power station burn rate in the second quarter of 2014 at 26.7% was, however, slightly up on a year earlier.

Based on data provided by Bentek Energy, US natural gas demand in the week ended 24 September was 3.7% higher than a year earlier. Power generation related demand was up by 4.9% while industrial and residential/commercial usage showed gains of 2.5% and 2.2% respectively..

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

The EIA is forecasting growth in US natural gas consumption of 1.8% to 72.6bcf/d in 2014. This contrasts with forecasts of about 1.0% earlier in the year. The latest forecast could prove conservative bearing in mind the solid showing through the first half and indeed the third quarter based on the latest Bentek data and expectations of a strengthening economy in the second half. As always, however, much will depend on weather conditions over the balance of the year. Interestingly, temperatures across much of the US in the third quarter of 2014 were below average which has dampened air conditioner usage and hence demand for electricity.

For 2015 the EIA is forecasting a marginal gain in natural gas consumption of 0.2% to 72.8bcf/d. This constitutes a significant upgrade from the decline of 0.5% forecast earlier in the year. The key factor depressing demand growth in 2015 relates to the assumption that weather conditions normalise which sharply reduces residential and commercial usage compared with 2013. The EIA is however forecasting a 4% gain in power station usage related to a combination of an assumed more competitive market for natural gas as prices slip and the closure of coal-fired generating capacity due to tightening emissions regulation. Tightening regulation will probably have a growing adverse impact on the coal burn rate in the years to come. Natural gas and renewables will be the beneficiaries.

Inventories: Comfortable for all but the harshest winters

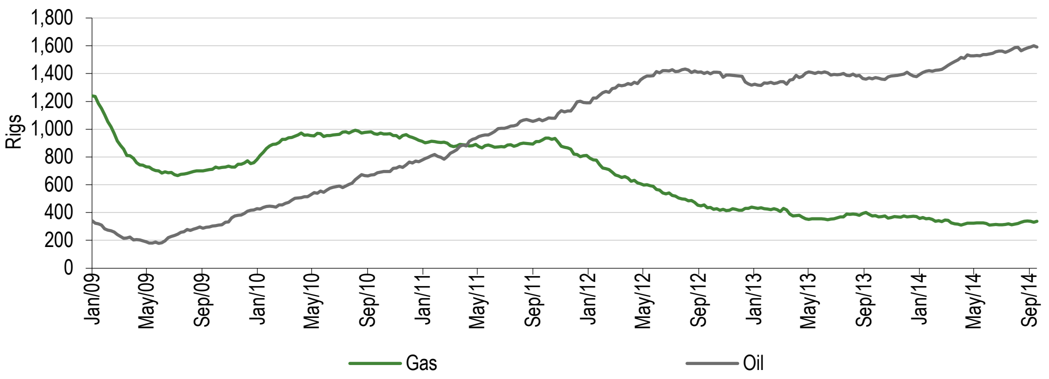
US natural gas inventories came under considerably greater than normal pressure in early 2014 due to a sustained period of exceptionally cold weather. However, the combination of the buoyant production backdrop and apparently subdued demand during the second and third quarters has resulted in a strong inventory build during the current injection season. Taking the period 4 April through 19 September 2014 net storage injections totalled 2.17bcf, according to the EIA. This compared with 1.67bcf for the comparable period in 2013 and an average of1.60bcf between 2009 and 2013.

On 19 September 2014 US natural gas inventories stood at 2.99 tcf which was down 11.4% on a year previously and 12.5% below the five-year average. The EIA is currently forecasting inventories of 3.4tcf at the end of the injection season in late October which looks a comfortable prediction based on the recent rate of travel. The forecast 2014 injection season peak is 10% or 0.37 tcf below the five-year average of 3.85 tcf. Inventories are likely to be comfortable during the extraction season from November to March for all but the harshest winters.

Drilling activity: Oil rig count trending higher, gas possibly bottoming out

US drilling activity has trended higher in 2014 and is now approaching record levels. Based on Baker Hughes data, the rotary rig count overall on 26 September, 2014 was 1,931, up 9.9% on end 2013 and 10.7% on a year earlier. The shortfall currently compared with the 4 November 2011 all-time high of 2,026 is 4.7%. The upward trend in the rig count in 2014 has continued to be driven by the oil sector. Since end 2013, the oil rig count has climbed by 15.2% to 1,592. This was nine short of a record 1,601 in the previous week and up16.9% up on a year earlier. In terms of basins, the key area of strength in 2014 has been the Permian Basin where the rig count has risen by 93 or 20% to 553 since end 2013. The DJ-Niobrara has also shown a strong 63% increase since end 2013, albeit from a much lower base than the Permian, while a group of miscellaneous basins have recorded a 23% gain to 398. This is 1% below the recent all-time high of 401. In the Williston Basin (Bakken petroleum system) the rig count is up 8% since 2013 year end. At 198, however the Williston rig count remains 8% below the June 2012 record of 224. Looking at the Eagle Ford formation, the rig count is down from end 2013 by 1.5% to 199.

Exhibit 12: Baker Hughes rig count



Source: Baker Hughes, Bloomberg

The dry gas dedicated rig count remains at depressed levels by the standards of the past ten or so years. The trend however shows signs of bottoming. The gas rig count on 26 September came in at 338, down about 10% on both end 2013 and a year ago. For perspective, at the peak in 2008 the gas rig count was around 1,600 and as recently as late 2011 was running at about 900. The declining trend continues to reflect still fairly marginal fully accounted natural gas economics at prevailing benchmark prices and greatly superior economics in liquids plays. Interestingly, however, dry gas drilling has regained a modicum of upward momentum in recent months. The 26 September rig count was around a six-month high. Compared with end 2013, the Marcellus dry gas rig count has dropped five to 82 but is around a five-month high. The dedicated dry gas Utica rig count at end September has shown a rise of two to 23 since end 2013. On the same basis the Utica oil rig count has risen by four to 21.

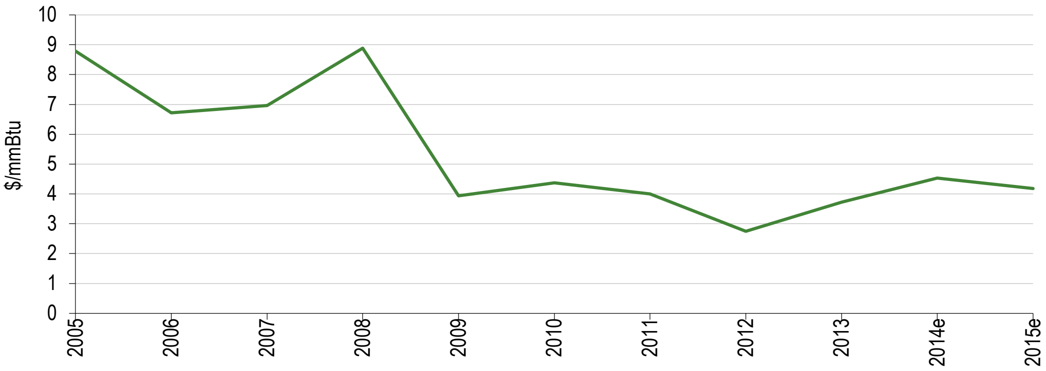
We continue to believe that US prices will probably have to exceed $5/mmBtu on a sustained basis before dry gas drilling activity decisively reverses the downward trend that has been apparent since late 2011. With the Henry Hub benchmark trading around $4/mmBtu at end September 2014 status a sustained recovery would not appear in the cards near term.

Recent price developments and outlook

Dry gas: Prices plunge in Appalachia, Dominion South arguably the new benchmark

After a strong showing in the first quarter of 2014 related to harsh winter weather across a broad swath of the country, US natural gas prices have subsequently trended downward. Taking the traditional Henry Hub, Louisiana benchmark, the spot price so far in 2014 has averaged \$5.43/mmBtu in the first quarter and \$4.59/mmBtu and \$3.93/mmBtu in the second and third quarters respectively. At the end of September 2014 the Henry Hub was trading at \$4.02/mmBtu down 6.7% on end 2013, although up12.9% on a year earlier.

Exhibit 13: Henry Hub natural gas price trend

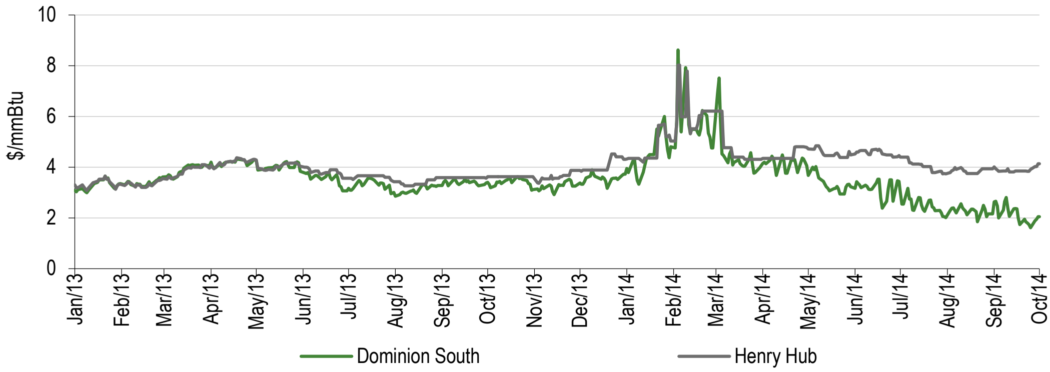


Source: Bloomberg

Increasingly influential Dominion South hub Arguably, the Henry Hub is losing relevance as the key US natural gas benchmark given the rapidly growing production build-up in the Appalachian region from the Marcellus and Utica formations. Prices in the region presently stand at a sizeable discount to the Henry Hub Louisiana benchmark. Taking Dominion Transmission's South Point pool with hubs in Lebanon Ohio and Oakford, Pennsylvania, the price at the end of September was a mere \$1.88/mmBtu. This was close to a low for the year and under half the Henry Hub quote. In the year-to-date end September 2014, the Dominion Transmission South price has averaged \$3.62/mmBtu with a quarterly sequence as follows: Q1 \$4.95, Q2 \$3.60 Q3 \$2.33. In all quarters the Dominion South price has therefore been at a substantial discount to the Henry Hub.

The Dominion South discount reflects slack demand, particularly during the summer months, in Appalachia and the eastern seaboard surging production and pipeline constraints. Effectively a sizeable supply surplus has built up in the region. Medium term pricing relief could come from petro-chemical industry expansion in the region and pipeline construction taking more gas to the eastern seaboard and westwards to the Midwest and southwest to potential LNG plants on the Gulf Coast.

Exhibit 14: Henry Hub vs Dominion South



Source: Bloomberg

Outlook: The general downward trend in US natural gas prices since the first quarter of 2014 reflects strong supply growth and lagging demand with the relatively cool summer being particularly significant in terms of the latter. Given the robust production trend, the critical issue for natural gas prices in the fourth quarter of 2014 and early 2015 concerns weather conditions. A mild fall could clearly send the Henry Hub significantly below $4/mmBtu while average to moderately below average winter temperatures could support prices at $3.95-$4.50/mmBtu. To send the Henry Hub significantly above the upper end of this range would probably require a severe winter along the lines of 2013/14.

Despite the weak trend of late, we are leaving our 2014 full-year Henry Hub forecast intact at $4.53/mmBtu. The forecast reflects an average for the fourth quarter of $4.15/mmBtu which constitutes a downgrade compared with the previous $4.40/mmBtu to reflect the weaker than expected carryover effect from the third quarter. Compared with the earlier forecast, the first quarter actual has been revised upward, the second quarter outcome of $4.59 was significantly higher than anticipated and the third quarter at $3.93 was somewhat lower than expected. For 2015 we have downgraded our Henry Hub forecast from $4.33/mmBtu to $4.18/mmBtu. The downgrade essentially reflects the evidence of a loosening supply/demand balance in recent months and the expectation that this trend will continue into 2015. The dip in average prices between 2014 and 2015 reflects the assumption that the severe winter weather of 2013/14 will be non-recurring. Effectively we are assuming that normal winter and summer temperatures prevail. Abnormally low temperatures during the first quarter and high temperatures in the summer could send the Henry Hub to $4.50/mmBtu or above in 2015. A mild winter by comparison might result in an average for the Henry Hub of $3.50/mmBtu or less.

Exhibit 15: Henry Hub quarterly price scenario

$/mmBtu	Q1	Q2	Q3	Q4	Average
2008	8.66	11.37	9.06	6.45	8.89
2009	4.54	3.70	3.17	4.37	3.94
2010	5.15	4.15	4.32	3.86	4.37
2011	4.18	4.37	4.12	3.33	4.00
2012	2.43	2.29	2.88	3.40	2.75
2013	3.49	4.02	3.55	3.84	3.73
2014e	5.43	4.59	3.93	4.15	4.53
2015e	4.40	4.00	4.20	4.10	4.18

Source: Bloomberg, Edison Investment Research. Note: Q114-Q314 are actuals.

NGLs

Natural gas liquids (NGLs) such as ethane (the highest volume NGL), propane (second highest volume), butane and natural gasoline are important petrochemical feedstocks, gasoline-blending agents, pipeline diluents and fuels. They are indeed valuable by-products of natural gas production.US NGL production has grown rapidly in recent years in tandem with the development of liquids-rich natural gas formations such as the Marcellus and Eagle Ford and more recently the western zone of the Utica. The US is comfortably the world's largest producer of NGLs.

In 2013, production, based on EIA data, increased from the previous year by 8.3% to 2.61mmb/d which comfortably outpaced the % gain in dry gas. Over the five years to 2013 the average growth rate has been 7.8%pa. In the year-to-date 19 September US NGL production has continued to grow rapidly. Production on this basis averaged 2.77mmb/d, up 12.6% on a year earlier while in the most recent four-week period there was a 20.5% year-on-year gain to 3.00mmb/d. The EIA is forecasting production to increase by 11.5% in 2014 and 7.2% in 2015. The forecasts appear entirely plausible based on the rate of travel in 2014 and may even be slightly on the conservative side.

NGL prices spiked in the first quarter of 2014 reflecting harsh weather which boosted demand particularly for propane and constrained supply due to equipment malfunctions and logistical issues. Since the first quarter, prices have trended strongly downward reflecting surging supply and lagging demand. At end September 2014 US NGL prices (Mt Belvieu, Texas) were down compared with end December 2013 levels as follows: ethane -36.2%, propane -17.6%, butane -10.6%, natural gasoline -9.5%. The year-on-year declines at end September were also highly significant as follows: ethane -9.7%, propane -3.9%, butane -13.8% and natural gasoline -2.8%. Thanks to positive carryover from 2013 plus the first quarter spike we believe that for 2014 as a whole ethane prices on average could be close to 2013 while those for propane might be up about 10%. This would imply prices of perhaps 27 cts/gallon and 111 cts/gallon respectively.

Near term, the trend in US NGL prices looks like remaining soft given the supply backdrop. Medium term, however, there is a possibility that the supply/demand balance could tighten somewhat given a prospective expansion in US petro-chemical industry capacity and the installation of export facilities for ethane. In terms of the last mentioned two major projects are underway at Marcus Hook on the Delaware River and adjacent to the Houston Ship Canal. Sunoco's Marcus Hook and Enterprise Products Houston projects are scheduled to come on-stream in 2015 and 2016 respectively. Note, there is already a thriving export market for propane/propylene. Exports of these commodities indeed surged from about 16mm barrels in the mid-2000s to 116.2mm barrels in 2013. In July propane/propylene exports were running at an annualised160mm barrels.

Natural gas economics: Dry gas distinctly marginal, wet gas the semblance of profitability

At a Henry Hub price of around $4.00/mcf dry gas producers should be able to generate a comfortable cash contribution. We believe however that most will struggle to be profitable on a fully accounted basis. Based on company reports, cash operating costs and royalties could be in the region of $3.16/mcf split around $1.00 for lifting, $0.24 for severance tax, $0.45 for G&A, $0.75 for pipeline tie-in and gathering and $0.72 for royalties. This would imply a cash contribution of $0.84/mcf at the above price. Finding and development costs we believe typically range from about $0.65/mcf to $3.00/mcf. At the bottom of this range and assuming the above cash operating/royalty costs but before allowing for the cost of capital, a dry gas producer would be modestly profitable at $4.00/mcf. It should be noted that the statement on economics is only indicative. In practice economics particularly on a fully accounted basis will vary widely depending on the resource play and the utilisation rate.

Looking at the situation in the Marcellus where dry gas prices currently are less than $2/mcf the economics are clearly more marginal than indicated above for producers dependent on Henry Hub prices. We believe cash operating costs might be slightly below those indicated above due to higher than average well productivity but we suspect that they are not much below $3/mcf including royalties. This would of course imply a sizeable cash loss based on realisations of $1.90/mcf or so. The Marcellus pioneer, Range Resources, gives its finding and development costs in the play as

$0.59/mcf so to achieve fully accounted breakeven a Marcellus dry gas producer might need gross realisations of about $3.6/mcf.

The saving grace of natural gas producers over the recent years of depressed dry gas prices has been by-product liquids production. According to Range Resources, liquids currently boost realisations in the Marcellus by $3.64/mcfe to about $5.1/mcfe (assume $1.9/mcf for dry gas and 24% shrinkage). Cash operating and capital costs will admittedly also be greater than for a dry gas producer due to extra processing and transportation costs. We nevertheless believe that a wet gas producer would still be comfortably profitable on a cash operating basis and possibly a fully accounted basis assuming late September prices. Wet gas producers dependent on Henry Hub prices and with realisations enhanced by an extra $3.64/mcfe for liquids (total realisations of $6.68/mcf after allowing for shrinkage) should, we believe, be comfortably profitable on all definitions presently.

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