GUINNESS ATKINSON FUNDS

Energy brief

Tim Guinness

April 2013

Commentary and Review by portfolio manager Tim Guinness

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REPORT HIGHLIGHTS

FUND NEWS

• Fund size $89 million at end of March

OIL

• WTI advances while Brent declines

WTI up 5% from $92 to $97 while Brent falls by 3% from $112 to $109. WTI-Brent spread narrows from $20 to $12. Brent averages $113 so far this year.

NATURAL GAS

• US gas price up by 17% to $4.10

Henry Hub spot traded up 60cents (c) to end March at $4.10 and has more than doubled from April 2012 low of $1.84. Price helped by very cold March, but underlying market looks about 1 billion cubic feet (Bcf)/day undersupplied. Storage overhang all but gone.

EQUITIES

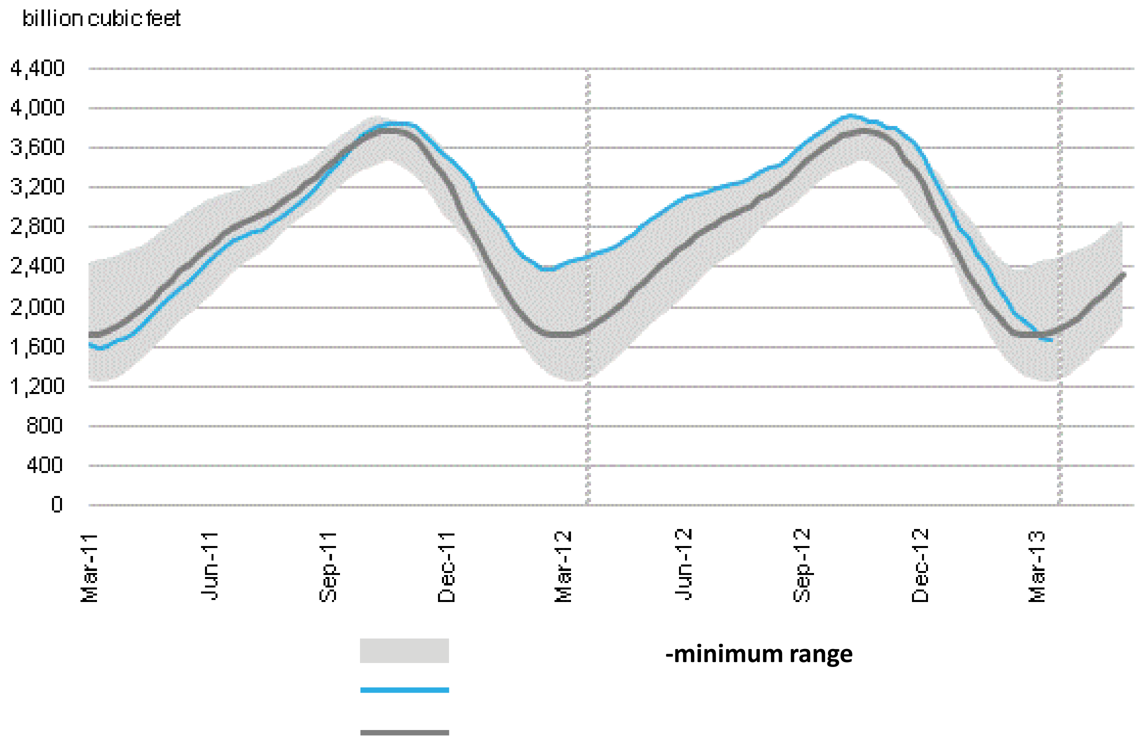
• Energy behind broad equities in March

The MSCI World Energy Index underperformed the MSCI World Index by 1.4% (all in US dollar terms).

Chart of the Month:

US natural gas in storage

The latest figures released by the Energy Information Administration (EIA) show that natural gas in storage is below its 5 year average for the first time since late 2011, which has had a positive impact on natural gas prices.

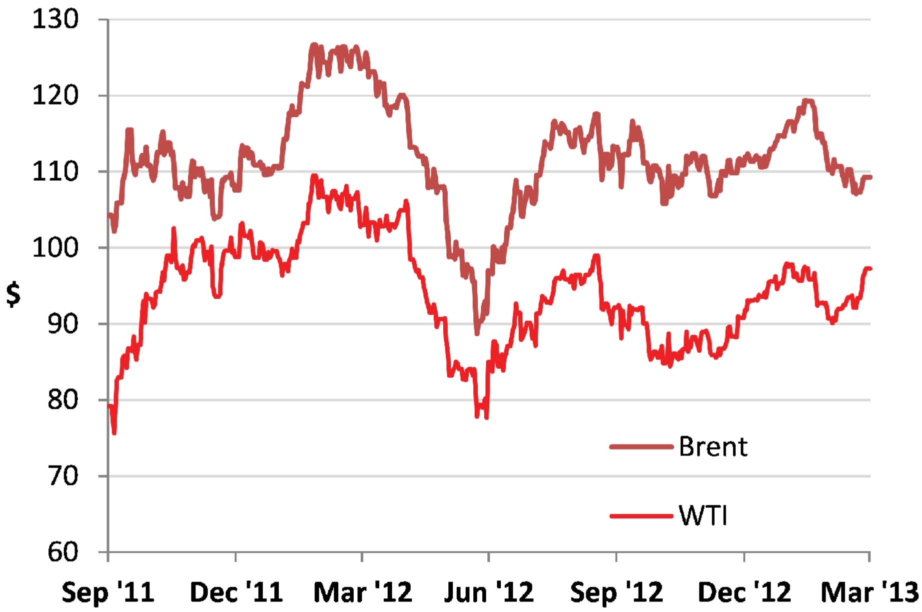


Source: US EIA (April 2013)

1. March 2013 Review

Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months September 30, 2011 to March 31, 2013



Source: Bloomberg

The West Texas Intermediate (WTI) oil price opened March at $92.05. After falling early in the month to a low of $90.12, the price rallied to close the month at a high of $97.23. So far this year, WTI has averaged $94.26. WTI averaged $94.12 in 2012 and $95.04 in 2011.

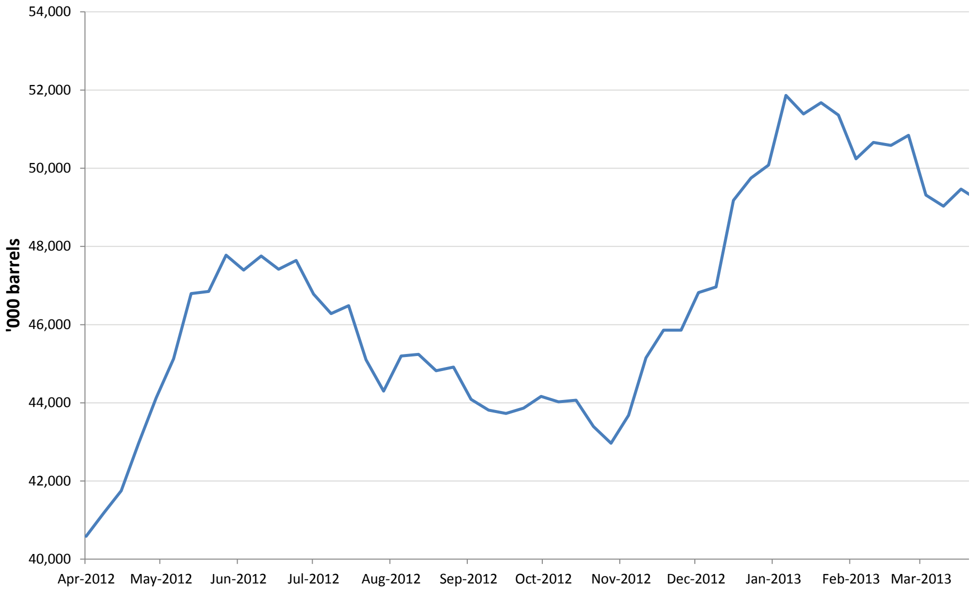
Brent declined slightly in March, falling from $111.66 to $109.27. The gap between the WTI and Brent benchmark oil prices that started at the beginning of 2011 narrowed from $20 at the start of the month to $12 at the end of March. The spread, caused by high stock levels resulting from increased US production in the Permian, Bakken and other areas, has narrowed considerably following capacity expansions in the Seaway Gulf Coast-Cushing pipeline, leading to falling stocks in the US mid-continent.

Factors which strengthened the WTI and Brent oil prices in March:

- **Falling crude inventories in Cushing**

As stated above, the narrowing in the Brent-WTI spread was largely due to a stronger WTI price resulting from falling mid-continent stock levels. Cushing, Oklahoma, the delivery point for the WTI benchmark, has seen stock levels boom in recent years, following rapid growth in US on-shore oil production. At the end of March, stock levels were 49.2 million(m) barrels, having been 51.9m barrels earlier in the year. The following graph shows the recent fall:

Figure 2: Crude oil stocks at Cushing, Oklahoma



Source: Bloomberg

- **Pipeline approval**

The Keystone XL pipeline, designed to transport crude from Alberta in Canada to the US Gulf Coast, received a boost during March when a Republican plan to encourage construction of the pipeline was approved by the US Senate. The project is currently awaiting approval from the US President.

- **Increase in net long futures position**

As detailed below, an increase in the New York Mercantile Exchange (NYMEX) net crude futures position added further support to the WTI oil price in March.

Factors which weakened the WTI oil price in March:

- **Global macroeconomic concern**

Events in Cyprus preoccupied many investors in March, as politicians struggled to contain a banking crisis. The announcement that private investors would face a haircut on deposits, and the long negotiations that followed, led to a period of market volatility. While attention has since shifted away from Cyprus, the episode highlights the tendency for stock markets to reflect sometimes a "risk-on/risk-off" behavior among its participants, and we are aware of the adverse consequences that a risk-off attitude can have on sentiment surrounding commodities.

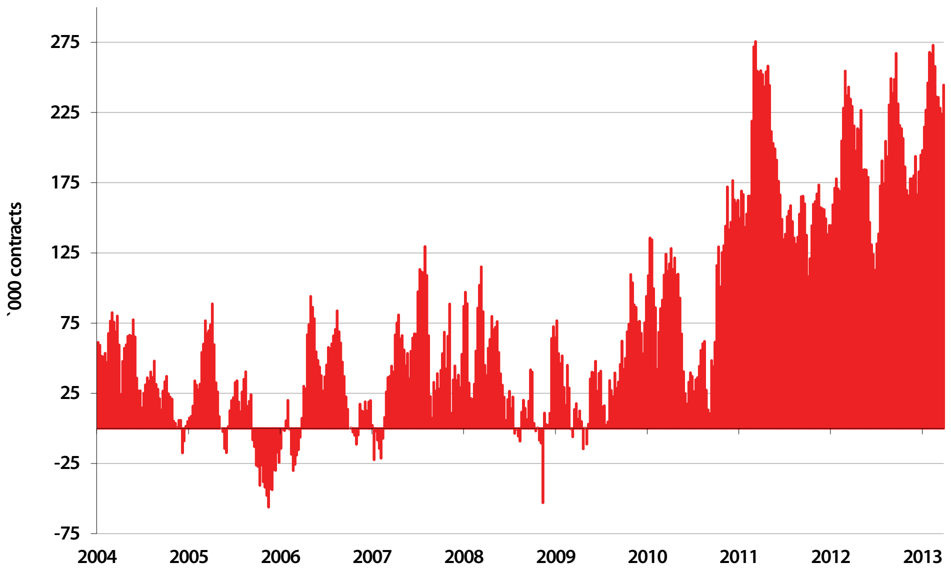
- **Inventory draws**

Organization of Economic Co-operation and Development (OECD) total crude and product stocks declined in February by 13m barrels, less than the five year average draw for the month of 28m barrels. Despite the weaker than average decline, and in the context of elevated US on-shore supply, OECD inventory levels are still well-behaved, falling within the 2002-11 historical range.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position increased slightly in March. It started the month at 236,000 contracts long, fell to 224,000 contracts, then rose to 245,000 contracts by month end. Though the position has unwound from the level of 273,000 contracts long reached in February 2013, we regard a net long position over 200,000 contracts to be relatively high.

Figure 3: NYMEX Non-commercial net futures contracts: WTI January 2004 – March 2013



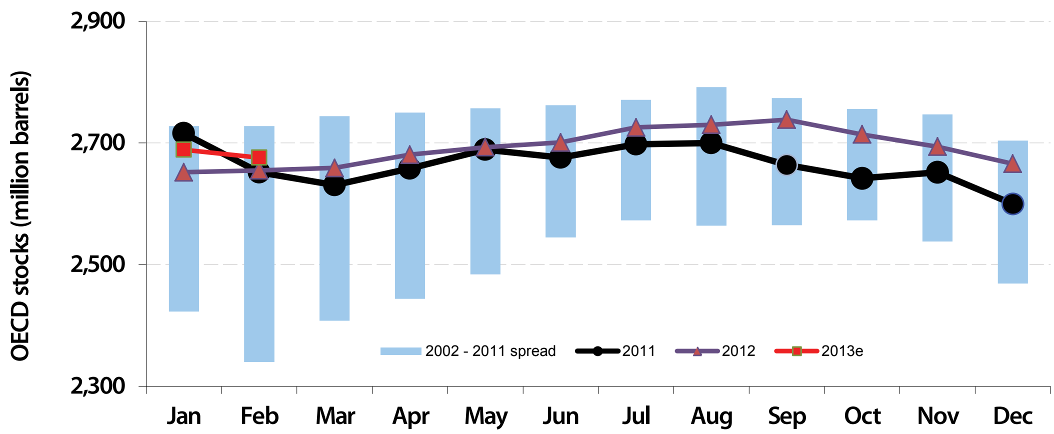
Source: Bloomberg/Nymex (March 2013)

OECD stocks

OECD estimated total crude and product stocks for February 2013 (published in the March 2013 International Energy Agency (IEA) Oil Market Report) declined by 13 million barrels from 2,689 million barrels, giving a total stock of 2,676 million barrels. Over the preceding five years, the average inventory draw in February was 28 million barrels.

After sitting for two years above the historic levels of OECD inventories, a noticeable shift downward occurred in 2011 in absolute inventory levels versus the 1998-2009 spread, as the graph below shows. The tightening happened even as OPEC-12 production increased to make up for lost Libyan and then Iranian production, and the IEA released 60 million barrels of emergency reserve oil. In 2012, inventories were generally looser than 2011, illustrating Saudi's attempts to keep production high and bring the Brent oil price back towards $100. Despite this, figures for recent months are reasonably well-behaved, falling at the top end of the 2002-2011 range.

Figure 4: OECD total product and crude inventories, monthly, 1998 to 2013



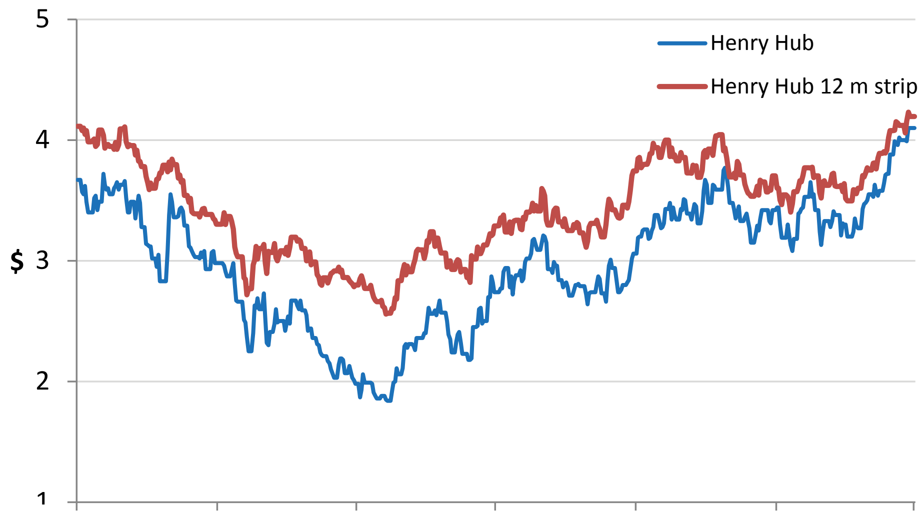
Source: IEA Oil Market Reports (March 2013 and older)

2. Natural Gas Market

The US spot natural gas price (Henry Hub) opened March at $3.50 per Mcf (1000 cubic feet) and rose steadily throughout the month to close at $4.10. The spot gas price has now more than doubled from a low of $1.84 in April 2012. The price averaged $2.75 in 2010, well down on the 2010 and 2011 averages of $4.38 and $4.00 and significantly below the average in each of the previous 5 years (2005-2009).

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) also rose over the month from $3.77 to $4.23. The strip price averaged $3.28 last year, having averaged $4.35 in 2011, $4.86 in 2010 and $5.25 in 2009.

Figure 5: Henry Hub Gas spot price and 12m strip ($/Mcf) September 30, 2011 to March 31, 2013



Source: Bloomberg

Factors which strengthened the US gas price in March included:

- **Market undersupplied**

The natural gas market appeared to be structurally undersupplied in March by just over 1 Bcf/day. We estimate this by considering the withdrawals from storage on a weather-adjusted basis. With detailed supply and demand for March not yet available, it is unclear to what extent this has been driven by declining supply or rising demand, but it is a positive sign for the price.

- **Cold weather**

Average temperatures in March were significantly below the seasonal norm, helping to boost heating demand for gas above the seasonal average. Total gas withdrawals from storage in March were 396 Bcf, versus the 5 year average of 112 Bcf. As a result, gas storage at the end of March stood 2% below the 5 year average, quite a contrast from the end of February when storage was 11% above average.

- **US production data**

The January data (latest available) from the Energy Information Agency indicated that total US natural gas production was down 0.7 Bcf/day (0.9%) month-on-month. The decline was likely magnified by temporary winter shut-ins of production. Total onshore production fell 0.6 Bcf/day (0.8%) month-on-month.

- **Low gas drilling rig count**

The US natural gas-directed rig count (reported by Baker Hughes) fell by 9% from 428 to 389 rigs during March. Over the last 18 months, the rig count has declined from 923 rigs (i.e. by 58%). The falling rig count reflects a suspension of activity in areas that are no longer economic to drill, given the depressed gas price. Of course there is a reasonable lead time between a fall in the rig count and a fall in production but the cumulative effects of the slide can only grow for as long as the rig count is low.

- **US railways demand**

While having no immediate impact, an interesting tidbit emerged in March with BNSF Railway announcing trials to switch their train engines from diesel to liquefied natural gas (LNG). BNSF Railway is the US's second largest freight railroad network. There are several operational and regulatory hurdles to overcome but their proposal to switch fuels is another example of potential new gas demand generated by the divergence between the oil and US gas price. Rail engines in the US currently consume around 0.25 million barrels per day (m b/day) of distillate, equivalent to around 1.5 Bcf/day of gas.

Factors which weakened the US gas price in March included:

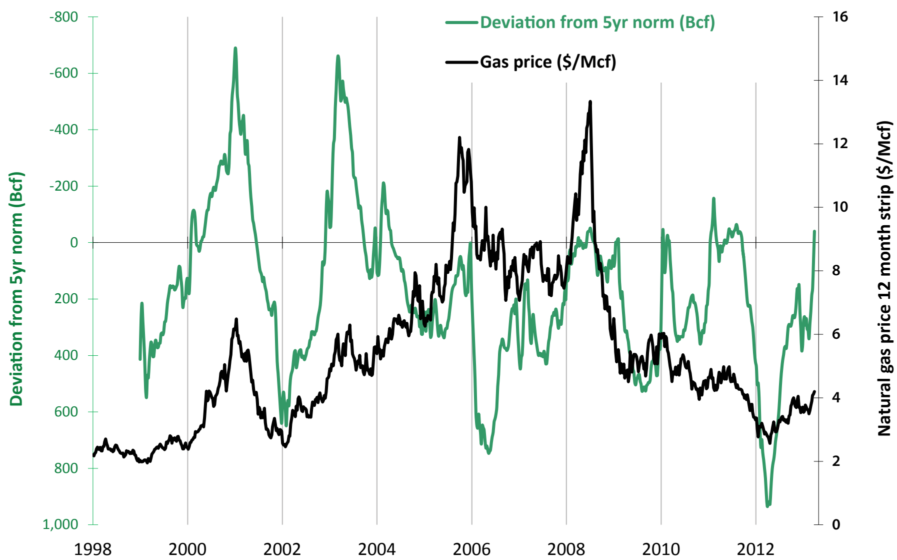
- **Gas to coal switching**

With the gas spot price rising from $3.50 to over $4.00, it is likely that some of the coal to gas switching that occurred in 2012 was reversed. At its peak in May/June 2012, we could identify around 6 Bcf/day of switching. We believe the level of switching is now down to less than 2 Bcf/day, but even this smaller amount could affect the overall balance of the gas market should it fluctuate from here.

Natural gas storage

Swings in the supply/demand balance for US natural gas should, in theory, show up in movements in gas storage data. The following graph shows the 12 month gas strip price (in black) against the amount of gas in storage expressed as the deviation from the 5 year storage average (in green). Swings in storage have frequently been a leading indicator to movements in the gas strip price.

Figure 6: Deviation from 5yr gas storage norm vs gas price 12 month strip (H. Hub $/Mcf)



Source: Bloomberg, EIA (April 2013)

The surplus of gas in the second half of 2008 and 2009, a result of oversupply during the recession, can be seen in gas storage data, with the inflection point in storage occurring in July 2008 and the storage line moving from negative (i.e. deficit) to positive (i.e. surplus) territory over this 18 month period. This coincided with the gas strip price falling from a peak of over $13 in July to below $5. An unusually cold 2009/10 winter boosted demand and pushed the gas storage level back into balance, only for oversupply to persist again for much of the rest of 2010. A cold 2010/11 winter followed by a hot 2011 summer tightened storage again, with storage levels staying around the 5 year average for much of this period.

The very mild 2011/12 winter (in combination with rising production) caused gas storage levels to balloon to record levels, driving prices down to their lowest levels for a decade. Since then, coal-to-gas switching and shut ins and the sharp rig count drop have worked in the other direction, seeing gas prices rising from their sub $2 lows in April 2012 to around $4 now.

We watch movements in gas storage closely as it is likely to be a coincident indicator, weather adjusted, for the start of a sustained gas price recovery.

3. Manager's Comments

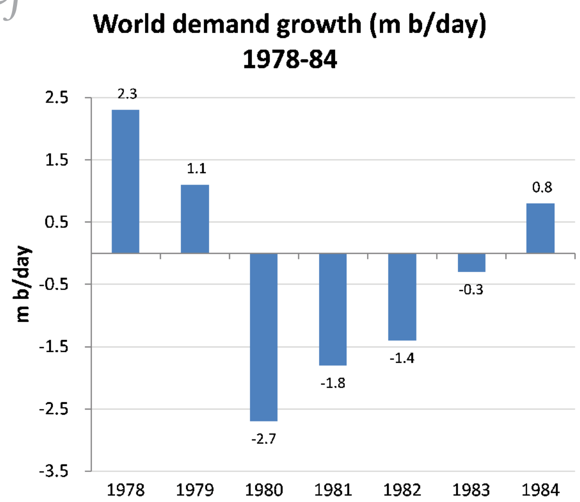
In January we posed three big energy questions which we think are relevant for energy investors over the next few years. First, is energy demand still rising faster than supply, or are we suddenly awash with hydrocarbons (oil and natural gas), as the media convey? Second, how does the energy sector fit into the commodity supercycle? Third, what then for energy equities, given many are on low valuation metrics at the current energy commodity price deck? Here are our most up-to-date thoughts on each:

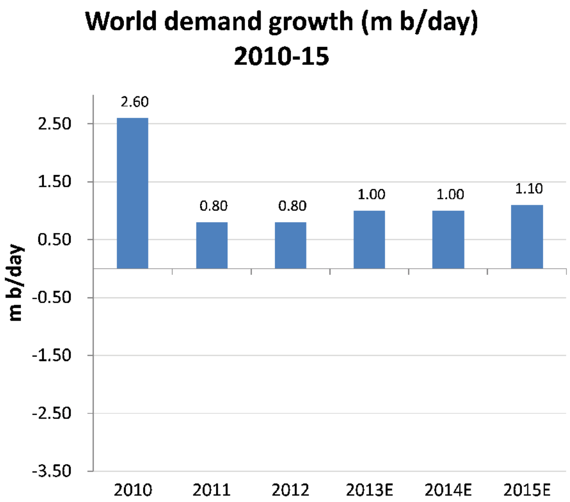
i) Emerging economy oil demand vs. non-OPEC supply growth (especially US shale)

The global oil market is overall relatively balanced. Under the surface, emerging economy demand is growing powerfully, driven by accelerating demand for cars and commercial vehicles as 4 billion people move into the $5,000–$25,000 GDP per capita range. We see emerging economy oil demand growing each year at 1.2–2m barrels(b)/day as a result. Offsetting the growth should be an annual demand decline of some 0.2–0.4m b/day from OECD economies. This could result in an additional 13m b/day of demand by 2022 (versus demand of 90m b/day today).

There is an impression that shale oil will meet this demand growth and more. Sadly, we see this as misplaced overenthusiasm.

We see shale just like the development of the Gulf of Mexico, North Sea and Alaska in the 1980s after the 1970s price hike. But with one huge difference: back then oil demand from the OECD economies had exploded from 1950-73. They were at the end of a 25 year journey adopting the motor vehicle; impetus was fading and demand then naturally corrected as prices jumped, as can be seen in the graph below. Now it is different. China's demand for oil per capita has not even reached that of the OECD in 1950. There are two decades of unrelenting oil demand growth to come while China's vehicle fleet moves from 100 million now to 400 million by 2030, with India and others following behind.





Source: IEA; Guinness Atkinson Asset Management estimates

Looking ten years forward to 2022, we see muted supply growth: perhaps 2-3m b/day from US shale oil and elsewhere perhaps Iraq 2m b/day, Africa 2m b/day, Brazil 1.75m b/day, Canada 1.25m b/day and Caspian 1m b/day, all of which must be offset against mature basin declines. If you doubt us, remember that Canada, for example, only grew its oil production by 0.9m b/day from 2002 to 2012, despite all the effort to develop its oil sands. Adding these together we get 10-11m b/d minus declines elsewhere, so we struggle to get supply up by 13m b/day.

Any temporary imbalances will be met by OPEC, and in particular, Saudi Arabia, Kuwait and United Arab Emirates (UAE) adjusting their production.

ii) US shale natural gas glut; strong global gas demand

The US shale gas glut which has captured the world's imagination is ending while (similar to oil demand) emerging economy gas demand growth is explosive. China's demand for natural gas is growing at 16% per annum (pa).

Over the past seven years, onshore US natural gas production has grown from circa(c.) 45 bcf/day to c.68 bcf/day following technological advances in horizontal drilling and fracking being applied to gas-rich basins. This growth equates simplistically to 23 bcf/day, or c.3–4 bcf/day of growth per year. This was absorbed for the first 5 years, but eventually, in late 2011, production growth overwhelmed demand (helped too by a very warm winter). Since then, the industry has reacted in classic fashion: the gas rig count has more than halved and electric utilities started switching from coal to gas (now the cheapest fuel) as gas moved below c$3.50/1000 cubic feet (mcf). We know this will rebalance the market. It's how markets work. The only issue is timing and the signs today are good: the massive storage overhang that developed in 2012 has all but disappeared now.

Our hunch is that in three years the gas price will be moving from 20% of the oil price ($3.50 gas is like $21/barrel oil) to 33% (if oil is $110 that is $36/barrel or $6.00 gas). That is 71% from $3.50 and 118% up on 2012 average price of gas of $2.75.

Outside the US, natural gas prices have remained very firm. So firm, in fact, that at the end of the year the UK National balancing point price was over $10/mcf, and prices in Japan were over $16/mcf – circa three and five times that in the US. And, surprise surprise, the driver is those pesky emerging economies again. China has grown its consumption of gas by 17% p.a. since 2000 and has now reached 14 bcf/day (one-fifth the consumption of the US). Remember, by the way, that China consumes 3.6x the amount of coal the US does. It shows every sign of likely growing its gas demand 4x in the next ten years. By 2022 we expect that demand could be 60 bcf/day. Globally, demand, now 315 bcf/day, will rise to 450 bcf/day by the same date if the last ten years are repeated (4.4% pa growth in the developing world; 0.8% pa in the developed world).

iii) Energy and the commodity supercycle

The current commodity secular bull market began in 1999/2000. Prior overcapacity had been worked off, and depressed prices started recovering. Two characteristics of this cycle stand out. The strength of China and other emerging country demand growth kicking in in 2003 and the banking crisis that erupted when it was barely 8 years old.

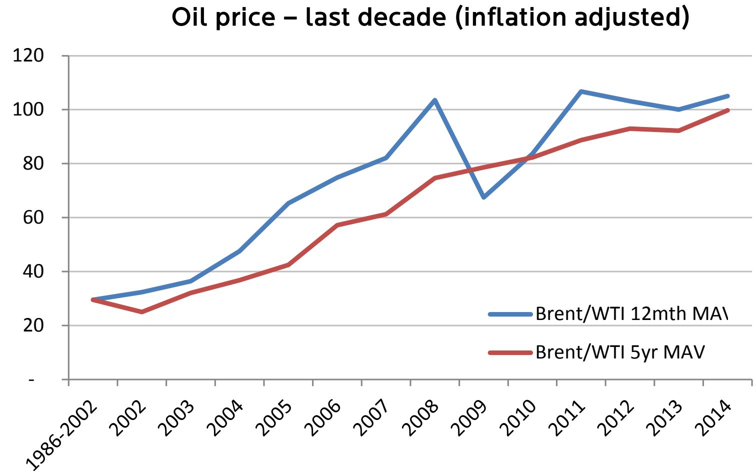
Our view is that both these factors are having an important effect on the super-cycle. On the one hand the banking crisis has lengthened the cycle as new energy capacity additions were delayed in the 2008-11 period. On the other the China growth factor has boosted overall emerging market demand, first as the country passed through a phase of industrialization and investment-led commodity demand (favoring iron, steel, aluminum and copper), now being replaced by consumer-led commodity demand (favoring energy and agribusiness).

We feel the oil price could average $100 this year (average of Brent and WTI). Inflation is doing its stuff. Global GDP in 2013 is now forecast to be around $78 trillion. We will likely consume 90.8m b/day of oil in 2013. At $100 average price that spend is $33.1 billion, or 4.2% of 2013 global GDP. History shows that when prices take oil spend to 7-8% pa, they never last; and that 2% of GDP is cheap. It's exceeded 4% in 15 of the last 40 years. It won't topple the world economy. For OPEC it's a price that looks fair; they will strive to achieve it. And it will likely rise from here at something like a fraction under global nominal GDP growth. Under this framework, it is relatively easy to picture the oil price at around $150 by 2020, which would be around 4-5% of nominal GDP by then.

iv) Energy equity valuations

March 2011 to June 2012 saw energy equities significantly underperform the broad market; investors believed the commodity super-cycle was over. But energy equities started outperforming again from July 2012 – and this is logical to us. The likely evolution of the commodity cycle is that demand for infrastructure commodities – copper, aluminium, iron ore – may well level off and prices weaken as capacity moves from tight to loose. But, typically, the next stage has been that commodities that are in growing demand from consumers remain firm and even strengthen – commodities like energy and agricultural goods.

Most recently there has been a renewed period of relative weakness, with the eight months outperformance since July 2012 being surrendered again in February/March. That said, the performance of our Global Energy Fund and that of the two main broad market indices – S&P500 and MSCI World – are very similar since July 2012. Our portfolio based on consensus estimates, is on a 2012 P/E ratio of 10.3x, as of 3/31/13, well below the broad market's 16.2. The discount gives a potential upside versus the broad market of 57% when energy PEs close the gap. History indicates they'll do so when the current oil price and long-run market expectations come together. $100 oil is around where that could happen.



Oil Price (inflation adjusted)													*Forecast*	
12 month moving average (MAV)	1986-2002	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	*2013*	*2014*
WTI	30	33	38	49	66	75	82	104	68	84	99	94	95	100
Brent	30	32	35	46	64	75	82	103	67	84	115	112	105	110
Brent/WTI 12mth MAV	**30**	**32**	**36**	**48**	**65**	**75**	**82**	**103**	**67**	**84**	**107**	**103**	**100**	**105**
Brent/WTI 5yr MAV	30	25	32	37	42	57	61	75	79	82	89	93	92	100

Source: Bloomberg (actuals); Guinness Atkinson Asset Management (forecasts)

The super-majors, to our way of thinking, are not expensive, and non-majors have become increasingly good value thanks to their underperformance of the broad market during 2011 and H1 2012. All this of course assumes the oil price stabilizes around the 5 year moving average price of $100 (blended Brent/WTI) and the gas price in due course recovers which is what we believe is increasingly likely to occur.

Energy equities are one of the better inflation hedges. If we see dollar inflation of 30/50% over the next decade it will be surprising if oil and gas prices do not rise by a comparable percentage.

4. Performance – Guinness Atkinson Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was up by 1.03% in March. The S&P 500 was up by 3.75% over the same period. The Fund was up by 0.95% over this period, underperforming the MSCI World Energy Index by 0.08% (all in US dollar terms).

Within the Fund, March's stronger performers were Ultra, JKX, Bill Barrett, Carrizo and Hess. Poorer performers were Petrominerales, JA Solar, Trina Solar, PetroChina and Gazprom.

Performance as of March 31, 2013

Inception date 6/30/04	Full Year 2009	Full Year 2010	Full Year 2011	Full Year 2012	1 year (annualized)	Last 2 years (annualized)	Last 5 years (annualized)	Since Inception (annualized)
Global Energy Fund	63.27%	16.63%	-13.16%	3.45%	1.34%	-9.73%	-0.33%	12.49%
MSCI World Energy Index	26.98%	12.73%	0.71%	2.54%	4.27%	-2.20%	1.04%	9.91%
MSCI World Index	30.78%	12.47%	-5.01%	16.60%	12.64%	6.73%	2.88%	6.24%
S&P 500 Index	26.47%	15.06%	2.09%	15.99%	13.99%	11.21%	5.81%	5.88%

Source: Bloomberg
Gross expense ratio: 1.27%

Performance data quoted represent past performance and does not guarantee future results. The investment return and principal value of an investment will fluctuate so that an investor's shares, when redeemed, may be worth more or less than their original cost. Current performance of the Fund may be lower or higher than the performance quoted. For most recent month-end and quarter-end performance, visit www.gafunds.com or call (800) 915-6566.

The Fund imposes a 2% redemption fee on shares held for less than 30 days. Performance data does not reflect the redemption fee and, if deducted, the fee would reduce the performance noted.

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5. Portfolio – Guinness Atkinson Global Energy Fund

Buys/Sells

There were no buys or sells in March.

Sector Breakdown

The following table shows the asset allocation of the Fund at **March 31, 2013.**

(%)	31 Dec 2007	31 Dec 2008	31 Dec 2009	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Mar 2013	*Change YTD*
Oil & Gas	**103.5**	**96.4**	**96.1**	**93.2**	**98.5**	**98.6**	**98.0**	***-0.6***
Integrated	66.2	53.7	47.2	41.2	39.6	39.1	39.2	*0.1*
Exploration and production	25.8	28.7	32.0	36.9	41.5	41.6	41.0	*-0.6*
Drilling	8.1	5.2	8.4	6.3	6.0	7.4	7.6	*0.2*
Equipment and services	3.4	6.4	5.4	5.3	6.6	7.1	6.7	*-0.4*
Refining and marketing	0.0	2.4	3.1	3.5	4.8	3.4	3.5	*0.1*
Coal and consumables	**2.5**	**2.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Solar	**0.0**	**0.0**	**0.0**	**3.2**	**1.2**	**1.2**	**1.1**	**-0.1**
Construction and engineering	**0.0**	**0.4**	**0.4**	**0.4**	**0.4**	**0.6**	**0.6**	**0.0**
Cash	**-6.0**	**0.9**	**3.5**	**3.2**	**-0.1**	**-0.4**	**0.3**	**0.7**
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**0.0**

Source: Guinness Atkinson Asset Management
Basis: Global Industry Classification Standard (GICS)

Guinness Atkinson Global Energy Fund Portfolio

The Fund at **March 31, 2013** was on an average price to earnings ratio (PE) versus the S&P 500 Index at 1,569 as set out in the table. (Based on S&P 500 'operating' earnings per share estimates of $49.5 for 2008, $56.9 for 2009, $83.8 for 2010, $96.4 for 2011 and $96.8 for 2012). This is shown in the following table:

	2007	2008	2009	2010	2011	2012
Fund PER	8.7	7.6	14.5	9.6	9.1	10.3
S&P 500 PER	19.0	31.7	27.6	18.7	16.3	16.2
Premium (+) / Discount (-)	*-54%*	*-76%*	*-47%*	*-49%*	*-44%*	*-36%*
Average oil price (WTI $)	$72.2/bbl	$99.9/bbl	$61.9/bbl	$79.5/bbl	$95/bbl	$94/bbl

Source: Standard and Poor's; Guinness Atkinson Asset Management

Portfolio Holdings

Our integrated and similar stock exposure (c.39%) is comprised of a mix of mid cap, mid/large cap and large cap stocks. Our five large caps are Exxon, BP, Chevron, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, StatoilHydro, Hess and OMV. As at March 31 2013 the median PE ratio of this group was 8.6x 2012 earnings. We have one Canadian integrated holding, Suncor, which merged in 2009 with PetroCanada. The company has significant exposure to oil sands and stands on an attractive PE of 9.5x 2012 earnings given the company's good growth prospects.

Our exploration and production holdings (c.40%) give us exposure most directly to rising oil and natural gas prices. We include in this category non-integrated oil sands companies, as this is the GICS approach. The stock here with oil sands exposure is Canadian Natural Resources. The pure E&P stocks are all largely in the US (Newfield, Devon, Chesapeake, Carrizo, Stone, Penn Virginia, Ultra, QEP and Bill Barrett) and three more (ConocoPhillips, Apache and Noble) which have significant international production. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves. All of the E&P stocks held also provide exposure to North American natural gas and include two of the industry leaders (Devon and Chesapeake). In PE terms, the group divides roughly into two: (i) ConocoPhillips, Apache, Chesapeake, Devon, Newfield, Ultra, Stone and Bill Barrett all with quite low PEs (5.5x – 11.5x 2011 earnings); and (ii) Noble, Carrizo, Penn Virginia and QEP with higher PE ratios (19.5x – 25.1x 2011 earnings). However, all look reasonably attractive on EV/EBITDA multiples.

We have exposure to eight (pure) emerging market stocks, though all but one are half-units in the portfolio. Two are classified as integrateds by the GICS (Gazprom and PetroChina) and five as E&P companies (JKX Oil and Gas, Dragon Oil, Afren, Petrominerales and Soco International). Gazprom is the Russian national oil and gas company which produces approximately a quarter of the European Union gas demand and trades on 2.7x 2012 earnings. PetroChina is one of the world's largest integrated oil and gas companies and has significant growth potential and advantages as a Chinese national champion. Dragon Oil is an oil and gas E&P-focused on offshore Turkmenistan in the Caspian Sea and trades on 7.8x 2012 earnings. JKX is a gas-focused E&P company with production in the Ukraine and trades on 4.4x 2012 earnings. Afren focuses on offshore West African production and trades on 8.6x 2012 earnings. SOCO International is an E&P company with production in Vietnam and exploration interests across East Africa in Angola, Democratic Republic of Congo and the Republic of Congo. Petrominerales is a Colombia-focused E&P trading on 2.8x 2012 earnings.

We have useful exposure to oil service stocks. The stocks we own are split between those which focus their activities in North America (land drillers Patterson and Unit on 13.3x and 11.0x 2012 earnings) and those which operate in the US and internationally (Helix, Transocean and Halliburton on 12.3x – 14.9x 2012 earnings).

Our independent refining exposure is currently in the US in Valero, the largest of the US refiners, which is currently trading at significant discount to book and replacement value. Valero has a reasonably large presence on the US Gulf Coast and is benefitting from the rise in US exports of refined products seen in recent times.

Our alternative energy exposure is currently a single unit split equally between two companies: JA Solar and Trina Solar. Both were loss making in 2012 due to dramatic falls in solar prices during the year. Trina is a Chinese solar module manufacturer and JA Solar is a Chinese solar cell manufacturer. Some measure of their recovery potential may be indicated by their 2010 PEs of 1.1x and 0.5x respectively.

Portfolio at March 31, 2013

Guinness Atkinson Global Energy Fund 31 March 2013

Stock	ID_ISIN	Curr.	Country	% of NAV	2006 B'berg mean PER	2007 B'berg mean PER	2008 B'berg mean PER	2009 B'berg mean PER	2010 B'berg mean PER	2011 B'berg mean PER	2012 B'berg mean PER	2013 B'berg mean PER
Integrated Oil & Gas												
Exxon Mobil Corp	US30231G1022	USD	US	3.53	13.76	12.4	10.6	23.2	15.1	10.7	11.5	11.3
Chevron Corp	US1667641005	USD	US	3.51	15.2	13.5	10.4	23.2	12.8	8.8	9.6	9.6
Royal Dutch Shell PLC	GB00B03MLX29	EUR	NL	3.37	8.1	6.5	7.5	14.4	10.5	7.8	7.7	7.7
BP PLC	GB0007980591	GBP	GB	3.55	6.3	6.4	5.1	8.9	6.1	6.1	7.6	8.2
Total SA	FR0000120271	EUR	FR	3.31	6.8	6.9	6.0	10.8	8.0	7.2	6.8	7.1
ENI SpA	IT0003132476	EUR	IT	3.40	6.2	6.8	6.3	12.3	9.3	8.9	8.7	9.0
Statoil ASA	NO0010096985	NOK	NO	3.32	7.5	10.2	7.7	14.0	10.5	9.1	8.6	8.5
Hess Corp	US42809H1077	USD	US	3.62	13.0	12.0	9.8	37.4	13.9	11.9	12.1	11.3
OMV AG	AT0000743059	EUR	AT	3.30	6.5	6.3	5.2	13.3	8.3	10.4	7.3	7.4
				30.89								
Integrated Oil & Gas - Canada												
Suncor Energy Inc	CA8672241079	CAD	CA	3.40	12.3	12.8	9.5	28.8	19.2	8.5	9.5	9.8
Canadian Natural Resources Ltd	CA1363851017	CAD	CA	3.36	22.3	15.4	10.0	13.5	13.4	14.1	20.5	15.5
				6.76								
Integrated Oil & Gas - Emerging market												
PetroChina Co Ltd	CNE1000003W8	HKD	HK	3.28	10.3	10.0	12.9	13.7	11.0	10.8	12.5	11.0
Gazprom OAO	US3682872078	USD	RU	1.64	5.0	4.9	4.3	4.9	3.8	2.6	2.7	3.0
				4.92								
Oil & Gas E&P												
ConocoPhillips	US20825C1045	USD	US	3.51	6.06	6.21	5.64	16.61	10.14	7.07	10.53	11.00
Apache Corp	US0374111054	USD	US	3.56	10.6	8.9	6.9	13.9	8.3	6.5	8.0	8.3
Bill Barrett Corp	US06846N1046	USD	US	1.26	14.3	20.9	7.5	12.0	10.0	11.5	382.5	41.8
QEP Resources Inc	US74733V1008	USD	US	1.19	nm	nm	nm	nm	23.0	19.5	25.6	22.0
Ultra Petroleum Corp	CA9039141093	USD	US	1.27	14.1	17.6	7.6	11.1	9.0	7.9	10.9	16.3
Devon Energy Corp	US25179M1036	USD	US	3.35	9.0	8.1	5.7	15.6	9.5	9.4	17.5	15.9
Chesapeake Energy Corp	US1651671075	USD	US	3.28	5.7	6.4	5.7	8.2	7.0	7.3	42.1	16.7
Noble Energy Inc	US6550441058	USD	US	3.64	30.5	21.3	16.4	34.3	28.0	22.0	25.3	17.9
Newfield Exploration Co	US6512901082	USD	US	2.94	6.4	7.0	7.1	4.4	4.9	5.5	9.2	10.9
Stone Energy Corp	US8616421066	USD	US	1.74	7.9	4.2	3.9	9.5	10.7	5.6	7.8	8.5
Carrizo Oil & Gas Inc	US1445771033	USD	US	1.68	36.3	36.8	14.3	17.5	20.3	25.1	17.7	12.3
Penn Virginia Corp	US7078821060	USD	US	1.06	2.2	2.2	1.6	nm	nm	nm	nm	nm
Trinity Exploration & Production PLC	GB00B8JG4R91	GBP	GB	0.25	nm	nm	nm	nm	nm	nm	nm	13.8
Ophir Energy PLC	GB00B24CT194	GBP	GB	0.80	nm	nm	nm	nm	nm	nm	nm	nm
Triangle Petroleum Corp	US89600B2016	USD	US	0.59	nm	nm	nm	nm	nm	nm	nm	nm
Pantheon Resources PLC	GB00B125SX82	GBP	GB	0.07	nm	nm	nm	nm	nm	nm	nm	nm
Cluff Natural Resources PLC	GB00B6SYKF01	GBP	GB	0.11	nm	nm	nm	nm	nm	nm	nm	nm
				30.29								
Oil & Gas E&P - Emerging markets												
Dragon Oil PLC	IE0000590798	GBP	GB	1.92	27.7	16.5	13.6	19.8	14.4	7.7	7.8	7.2
Petrominerales Ltd	CA71673R1073	CAD	CA	0.89	35.8	12.4	4.8	6.2	2.5	1.7	2.8	7.3
Afren PLC	GB00B0672758	GBP	GB	1.64	nm	nm	nm	178.2	33.4	16.8	8.6	8.5
Soco International PLC	GB00B572ZV91	GBP	GB	1.65	53.8	49.5	53.2	33.1	45.7	29.5	8.2	7.2
JKX Oil & Gas PLC	GB0004697420	GBP	GB	0.74	2.3	1.8	2.3	2.4	2.7	3.2	4.4	5.0
WesternZagros Resources Ltd	CA9600081009	CAD	CA	0.46	nm	nm	nm	nm	nm	nm	nm	nm
				7.30								
Drilling												
Transocean Ltd/Switzerland	CH0048265513	USD	US	0.87	17.7	4.8	3.6	4.4	8.7	36.6	14.9	11.2
Patterson-UTI Energy Inc	US7034811015	USD	US	3.32	5.9	9.4	10.1	nm	35.2	11.1	13.3	15.9
Unit Corp	US9092181091	USD	US	3.44	6.8	8.0	6.7	17.3	15.0	11.1	11.0	12.4
				7.62								
Equipment & Services												
Halliburton Co	US4062161017	USD	US	3.39	18.5	15.9	18.6	30.9	20.1	12.1	13.6	13.4
Helix Energy Solutions Group Inc	US42330P1075	USD	US	3.27	8.0	6.9	9.4	39.4	43.3	15.2	12.3	20.6
Shandong Molong Petroleum Machinery Co Ltd	CNE1000001N1	HKD	HK	0.09	12.4	8.6	5.7	15.9	6.2	8.6	nm	nm
				6.75								
Solar												
Trina Solar Ltd	US89628E1047	USD	US	0.61	nm	5.0	3.0	2.2	1.1	121.0	nm	nm
JA Solar Holdings Co Ltd	US4660902069	USD	US	0.45	4.2	11.2	16.6	nm	0.5	nm	nm	nm
				1.06								
Oil & Gas Refining & Marketing												
Valero Energy Corp	US91913Y1001	USD	US	3.49	5.5	5.8	8.4	nm	28.7	11.4	9.3	8.0
				3.49								
Construction & Engineering												
Kentz Corp Ltd	JE00B28ZGP75	GBP	GB	0.63	nm	25.8	26.1	25.7	17.7	13.4	11.3	9.8
			Cash	0.29								
			Total	100								
				PER	9.0	8.7	7.6	14.5	9.6	9.1	10.3	10.5
				Med. PER	8.5	8.8	7.5	14.0	10.5	9.9	10.1	10.9
				Ex-gas PER	9.4	9.0	8.3	16.2	9.8	9.3	9.6	9.9

The Fund's portfolio may change significantly over a short period of time; no recommendation is made for the purchase or sale of any particular stock.

6. Outlook

Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply over the last 10 years, together with the IEA forecasts for 2013.

	2003	2004	2005	2006	2007	2008	*2009*	2010	2011	*2012*	2013e
											IEA
World Demand	79.3	82.5	84.0	85.2	87.0	86.5	85.4	88.1	88.9	*89.8*	*90.6*
Non-OPEC supply (includes Angola and Ecuador for periods when each country was outside OPEC[1])	49.1	50.3	50.4	51.3	50.5	49.6	51.4	52.7	52.8	*53.4*	*54.5*
Angola supply adjustment[1]	-0.9	-1.0	-1.2	-1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ecuador supply adjustment[1]	-0.4	-0.5	-0.5	-0.5	-0.5	0.0	0.0	0.0	0.0	0.0	0.0
Indonesia supply adjustment[2]	1.0	1.0	0.9	0.9	1.0	1.0	0.0	0.0	0.0	0.0	0.0
Non-OPEC supply (ex. Angola/Ecuador and inc. Indonesia for all periods)	48.8	49.8	49.6	50.3	51.0	50.6	51.4	52.7	52.8	53.4	54.5
OPEC NGLs	3.9	4.2	4.3	4.3	4.3	4.5	4.9	5.4	5.8	*6.2*	*6.4*
Non-OPEC supply plus OPEC NGLs (ex. Angola/Ecuador and inc. Indonesia for all periods)	52.7	54.0	53.9	54.6	55.3	55.1	56.3	58.1	58.6	59.6	60.9
Call on OPEC-12[3]	26.6	28.5	30.1	30.6	31.7	31.4	29.1	30.0	30.3	30.2	29.7
Iraq supply adjustment[4]	-1.3	-2.0	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.7	-3.0	-3.3
Call on OPEC-11[5]	25.3	26.5	28.3	28.7	29.6	29.0	26.7	27.6	27.6	27.3	26.4

[1]Angola joined OPEC at the start of 2007, Ecuador rejoined OPEC at the end of 2007 (having previously been a member in the 1980s)
[2]Indonesia left OPEC as of the start of 2009
[3]Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela
[4]Iraq has no offical quota
[5]Algeria, Angola, Ecuador, Iran, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela

Source: 2003 - 2008: IEA oil market reports; 2009 - 13: 13 March 2013 Oil market Report

Global oil demand in 2012 was 2.8m b/day up on the previous 2007 peak. This means the combined effect of the 2007-8 oil price spike and the 2008/09 recession was quite small and has been shrugged off remarkably quickly. The IEA forecast a further 0.8m b/day rise in demand in 2013, which would take oil demand to a new all-time high of nearly 90.6m b/day.

OPEC

Four years ago, in order to put a floor under a plunging oil price, OPEC announced in its December 17, 2008 meeting a new quota target of 25.0m b/day with effect from January 1, 2009. This figure represented a 4.2m b/day cut from the actual OPEC-11 September 2008 production level (29.2m b/day). Since then, quotas remained unchanged until the OPEC meeting on December 13 2011, at which OPEC substituted a 30 m b/day target without specifying individual country quotas. The statement read as follows:

"In light of .... the demand uncertainties, the Conference decided to maintain the current production level of 30.0 mb/day, including production from Libya, now and in the future. The Conference also agreed that Member Countries would, if necessary, take steps (including voluntary downward adjustments of output) to ensure market balance and reasonable price levels. In taking this decision, Member Countries confirmed their preparedness to swiftly respond to developments that might have a detrimental impact on orderly market developments. Given the ongoing worrying economic downside risks, the Conference directed the Secretariat to continue its close monitoring of developments in supply and demand, as well as non-fundamental factors, such as macro-economic sentiment and speculative activity, keeping Member Countries abreast at all times."

The 30m b/day figure includes 2.7m b/day for Iraq, so in effect 25.0m b/day for OPEC-11 was moved up to 27.3m b/day. The timing of this announcement was clearly complicated by numerous issues: notably (1) a range of tricky problems in four OPEC member countries – Libya (recovery from civil war), Iran (western sanctions over nuclear weapons development), Venezuela (an ailing president), Nigeria (tribal unrest in the delta and sectarian unrest elsewhere); (2) production problems in certain non OPEC countries that might or might not resolve themselves speedily (Yemen, Syria and Southern Sudan); and (3) a real problem in forecasting how Iraq might develop. Our view is that this 30m b/day needs to be taken as a marker in the sand (this is where we would like to see production all things being normal) but little more than that at present. That said, March 2013 production for OPEC-11 is reported to be around 27.4m b/day, indicating that OPEC are currently reasonably well aligned with their overall target. None of this changes our view that OPEC may be ill-disciplined when prices are high but remain capable of being totally effective at cutting production when the oil price weakens significantly – as they did in December 2008, 2006, 2001 and 1998.

OPEC met in June 2012 and in December 2012 and no changes to production levels were made. The next meeting is scheduled for May 2013.

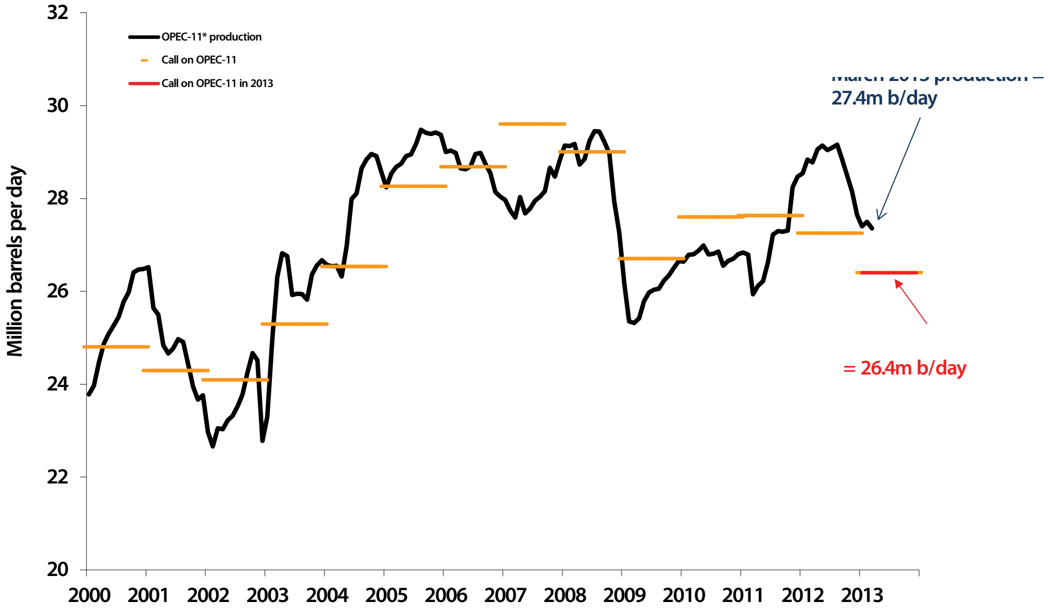
The table below shows changes in production among OPEC-12 since the end of 2010 and shows how production is running well ahead of pre-Middle East and North Africa (MENA) unrest levels. In addition to the non-OPEC problems mentioned above, Saudi Arabia's increased production is an indication of their desire to see US and European sanctions succeed against Iran (so avoiding military action against Iran by Israel). Saudi are well aware that if the oil price is $120+, Iran's overall oil revenues are strong even if production weakens. Saudi production alone is up around 0.75m b/day, and total OPEC-12 production is 1.4m b/day higher than December 2010.

('000 b/day)	31-Dec-10	31-Mar-13	Change
Saudi	8,250	9,000	750
Iran	3,700	2,700	-1,000
UAE	2,310	2,670	360
Kuwait	2,300	2,820	520
Nigeria	2,220	1,810	-410
Venezuela	2,190	2,850	660
Angola	1,700	1,780	80
Libya	1,585	1,300	-285
Algeria	1,260	1,200	-60
Qatar	820	720	-100
Ecuador	465	504	39
OPEC-11	26,800	27,354	554
Iraq	2,385	3,200	815
OPEC-12	29,185	30,554	1,369

Source: Bloomberg LP (March 2013)

The graph below shows the estimated call on OPEC-11 for 2013, which we currently estimate to be around 26.4m b/day versus apparent production of 27.4m b/day. Given that the market is in reasonable balance, it suggests that the actual call has recently been higher than 26.4m b/day. A number of leading commentators bridge the gap via 'missing' demand, a reference to non-OECD demand, in particular, being higher than the IEA are reporting.

Figure 7: OPEC apparent production vs. call on OPEC 2000 – 2013



Source: Bloomberg/IEA Oil Market Report (March 2013)

Supply looking forward

The non-OPEC world is struggling to grow production meaningfully. The growth was 2% p.a. from 1998-2003, 0.2% p.a. from 2003-2008 and 1.9% p.a. from 2008-2012.

Since 2010, non-OPEC production is up by only 0.7m b/day (0.1m b/day in 2011 and 0.6m b/day in 2012). Nearly all of the growth has come from the successful development of shale oil and oil sands in North America (+1.7m b/day over 2 years), implying that the rest of the non-OPEC region has declined by 1.0m b/day over this period. The decline in the rest of non-OPEC has been driven by a combination of political (Sudan; Syria & Yemen) and operational/geological (UK & Norwegian North Sea) factors.

The IEA forecast non-OPEC supply growing by 1.1m b/day in 2013, driven again by North American supply (+1.1m b/day). Other areas expected to grow their production include Brazil, Sudan, Egypt and China, offset by declines in the North Sea, Mexico and Russia.

Looking further ahead, we must consider in particular potential increases in supply from two regions: Iraq and North America. Starting with Iraq, the question of how big an increase is likely, in what timescale, and the reaction of other OPEC members are all important issues. Our conclusion is that while an increase in Iraqi production may be possible (say, 2m barrels over the next 5 years), if it occurs it will be surprisingly easily absorbed by a combination of OPEC adjustment, if necessary, weak non-OPEC supply growth and continuing growth in demand from developing countries of c.15m b/day over the next 10 years. Iraqi production was running at 3.2m b/day in March 2013, down from a high of 3.6m b/day in mid-2000. Despite this potential, continued unrest across the country does not fill us with confidence that growth can easily be achieved.

The recent growth in US shale oil, in particular from the Bakken, Permian and Eagleford basins, raises the question of how much more there is to come. So far, new oil production from these sources amounts to around 1.6m b/day. Our assessment is that US shale oil is a high cost source of oil but one that is viable at current oil prices. In total, it could be comparable in size to the UK North Sea, i.e. it could grow by a further 2m b/day between now and 2016, though we note recent comments from the management of Core Laboratories, a leading reservoir analysis company, that the market is overestimating the prospectivity of US oil shale and that we are unlikely to see more than an additional 0.6m b/day over the next three years (i.e. growth of 0.2m b/day per year to 2015). We also observe that since the discovery of the Bakken, Eagleford and Permian, the US has struggled to find another large shale resource, despite two years of trying.

Similar opportunities to exploit unconventional oil likely exist internationally, notably in Argentina (Vaca Muerta), Russia (Bazhenov), China (Tarim and Sichuan) and Australia (Cooper). However, the US is far better understood geologically; the infrastructure in the US is already in place; service capacity in the US is high and the interests of the landowner are aligned in the US with the E&P company. In most of the rest of the world, the reverse of each of these points is true, and as a result, we see international shale 5-10 years behind North America.

We must also keep an eye on future sources of new conventional oil supply outside OPEC. In Kazakhstan, the Kashagan field that is currently in development is expected to begin producing commercial volumes in mid-2013. Though initial volumes are lower, production is anticipated to reach between 1-1.5m b/day by around the end of the decade.

Demand looking forward

The IEA reported growth in oil demand in 2012 of 0.9m b/day, comprising an increase in non-OECD demand of 1.5m b/day and a decline in OECD demand of 0.6m b/day. The non-OECD growth forecast for 2013 is similar to 2012 at 1.2m b/day. The components of this growth can be summarized as follows:

Figure 8: Non-OECD oil demand

Million b/day	Demand					Growth			
	2009	2010	2011	2012	2013	2010	2011	2012	2013
Asia	18.25	19.70	20.28	20.97	21.60	1.45	0.58	0.69	0.63
M. East	7.10	7.32	7.40	7.65	7.80	0.22	0.08	0.25	0.15
Lat. Am.	5.70	6.04	6.30	6.52	6.66	0.34	0.26	0.22	0.14
FSU	4.00	4.15	4.45	4.61	4.75	0.15	0.30	0.16	0.14
Africa	3.37	3.30	3.26	3.40	3.57	-0.07	-0.04	0.14	0.17
Europe	0.70	0.68	0.69	0.71	0.72	-0.02	0.01	0.02	0.01
	39.12	41.19	42.38	43.86	45.10	2.07	1.19	1.48	1.24

Source: IEA Oil Market Report (March 2013)

As can be seen, Asia has settled down into a steady pattern of growth since 2010. Collective growth in the Middle East, Latin America, Former Soviet Union (FSU) and Africa is likely in 2013 to match that in Asia. These other non-OECD regions are all central to the developing world industrialization and urbanization thesis and should not be overlooked.

For OECD demand in 2013, the IEA's forecast of a decline of 0.4m b/day sees North America flat and Europe and the Pacific down. The expected decline in European demand reflects weak economic expectations for the region.

Global oil demand over the next few years is likely to follow a similar pattern, with a shallow decline in the OECD more than offset by strong growth in the non-OECD area. The decline in the OECD reflects improving oil efficiency over time, though this effect will be dampened by population and vehicle growth. Within the non-OECD, population growth and rising oil use per capita will both play a significant part. Price and the trajectory of global GDP will have an effect at any point in the short term, but overall we would not be surprised to see average annual demand growth of around 1.5m b/day to the end of the decade. This would represent a growth rate of 3% p.a., no greater than the growth rate over the last 15 years (3.2% p.a.).

Conclusions about oil

From the low of $31.42 on December 22, 2008 we saw the oil price (WTI) recover to above $70 by May 2009, and range trade around $65-$85 for the subsequent 20 months. Since November 2010 it has generally moved above this range, trading in a wider range of $80-$110. Brent's trading range over the same period has been higher, at $90-$125.

The table below summarises our view by showing our oil price forecasts for WTI and Brent in 2013 against their historic levels, and rises in percentage terms that we have seen in the period from 2002 to 2012.

Figure 9: Average WTI & Brent yearly prices, and changes

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013e
Average WTI ($)	31.2	41.7	56.6	66.1	72.2	99.9	61.9	79.5	95.0	94.1	95
Average Brent ($)	28.9	38.5	54.7	65.5	73.2	97.1	62.5	79.7	111.0	112.0	105
Average Brent and WTI	30.1	40.1	55.7	65.8	72.7	98.5	62.2	79.6	103.0	103.1	100
Average Brent and WTI Change+ y-o-y ($)		10.1	15.6	10.2	6.9	25.8	-36.3	17.4	23.4	0.05	-3.05
Avge Change+ y-o-y (%)		33%	39%	18%	10%	35%	-37%	28%	29%	0%	-3%

We think the most likely scenario going forward is that we will see the average price of Brent and WTI in the trading range of $90-110. Once the floor of this range looks threatened, OPEC will start to cut back and any significant price weakness below $100 (Brent) will be prevented by OPEC cuts. Should the oil price rise much over $125 and we think demand will start to weaken, putting a ceiling on the price for the time being (absent a supply shock).

In the short term, the restoration of most of Libya's oil production post-civil war is being countered by supply disruption in Syria, Yemen and foremost, Iran. In Syria, with Hezbollah and Iran backing the Alawite/Shia minority government and Saudi sources financing the arming of Sunni rebels, there is a clear risk that Iran responds by trying to destabilise the Shia (oil producing) eastern region of Saudi Arabia. As regards Iran, the continuing rhetoric between Iran and the West, with US and European policy of oil embargoes from July, underlines that we are only one ill-judged military move away from another oil spike. In Iraq stability remains elusive. At the heart of it all, we believe that Saudi are working hard to try and maintain a 'good' oil price (Brent at $100-110).

Natural gas market

Supply & demand recent past

On the demand side, industrial gas demand and electricity gas demand, each about a third of total US gas demand, are key. Commercial and residential demand, which make up the final third, have been fairly constant on average over the last decade – although yearly fluctuations due to the coldness of winter weather can be marked.

Industrial demand (of which around 30% comes from petrochemicals) tends to trend up and down depending on the strength of the economy, the level of the US dollar and the differential between US and international gas prices. Between 2000 and 2009 industrial demand was in steady decline, falling from 22.2 Bcf/day to 16.9 Bcf/day. Since 2009 the lower gas price (particularly when compared to other global gas prices) and recovery from recession has seen demand rebound, up in 2012 to around 19.5 Bcf/day. The supply side fundamentals for natural gas in the US are driven by 5 main moving parts: onshore and offshore domestic production, net imports of gas from Canada, exports of gas to Mexico and imports of liquefied natural gas (LNG). Of these, onshore supply is the biggest component, making up over 80% of total supply.

Since the middle of 2008 the weakening gas price in the US reflects growing onshore US production driven by rising gas shale and associated gas production (coming from growing onshore US oil production). These trends initially were mitigated by declining offshore production and falling net Canada and LNG imports and rising exports to Mexico. Most recently, from about September 2011, the mitigating factors became exhausted and a net imbalance developed. This, combined with very warm winter temperatures in early 2012, caused gas in storage to balloon and precipitated a gas price sell off. Since around April 2012, we have seen the gas rig count fall month on month as producers seek to cut back supply. We also saw significant coal to gas switching by US electric utilities, particularly during the summer of 2012, though much of these has now unwound again.

Total gas demand in 2012 (excluding Canadian exports) is estimated to have been 71.8 Bcf/day, up by 3.3 Bcf/day (4.8%) vs. 2011 and up 6.1 Bcf/day (9%) vs. the 5 year average. The principal contributor to the increase in 2012 vs. 2011 was power generation (+4.2 Bcf/day), driven by coal to gas switching. Other notable changes were industrial demand (+0.6 Bcf/day), exports to Mexico (+0.4 Bcf/day) and residential/commercial demand (-2.2 Bcf/day), which was pulled lower by the very warm start to 2012.

Overall, while gas demand in the US has been reasonably strong over the past three years, it has been trumped over this period by a rise in onshore supply, pulling the gas price lower.

Supply Outlook

Change in Rig Count

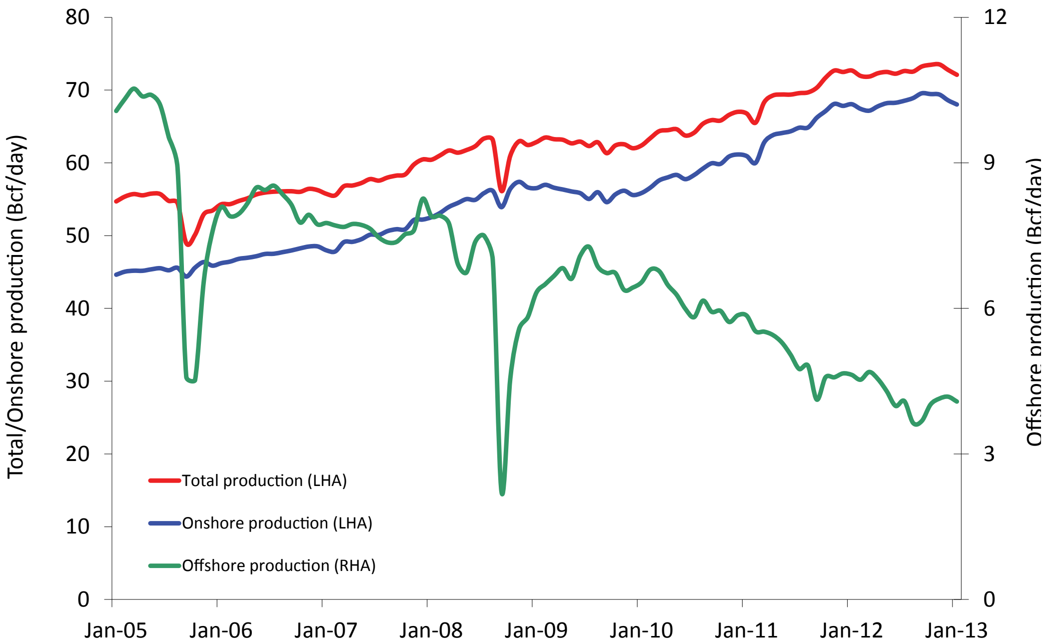
The onshore drilling rig count is the key driver of gas supply. When looking at changing totals, however, the accelerating shift from vertical to horizontal drilling has to be factored in as too does growing associated gas from rising onshore oil production, itself linked to a rising US oil rig count.

In total, the onshore gas rig count has dropped from a 1,606 peak in September 2008 to 389 at end-March 2013. Over the same period the oil rig count has risen from 416 to 1,354. The total number of rigs has therefore declined recently but not changed hugely (it has gone from 2,031 Aug 2008 to 1,990 Sep 2011 to 1,748 March 2013. Within this, however, the mix has changed as illustrated by the following table:

RIG COUNT BHI	Aug 2008		Sep 2011		Mar 2013	
Gas Rigs	1606		923		389	
Oil Rigs	416		1060		1354	
Misc Rigs	9		7		5	
Total Rigs	**2031**		**1990**		**1748**	
		%		*%*		*%*
Horizontal Rigs	626	*31%*	1135	*57%*	1099	*63%*
Directional Rigs	388	*19%*	238	*12%*	206	*12%*
Vertical Rigs	1017	*50%*	617	*31%*	443	*25%*
Total Rigs	**2031**	*100%*	**1990**	*100%*	**1748**	*100%*

One result of the change from vertical to horizontal drilling has been that onshore gas supply has continued to rise (the average productivity per rig has grown dramatically) and is now at c 68.0 Bcf/day, around 10.6 Bcf/day (18%) above the 57.4 Bcf/d peak in 2009 before the rig count collapsed. But as we mentioned earlier, we do not believe this growing excess in production over demand can continue indefinitely with natural gas trading well below the marginal cost of supply: a combination of reduced capital spending by the exploration companies, lowering production, and growing natural gas demand stimulated by the low gas price will rebalance the market, as is now happening.

Figure 10: US natural gas production 2005 – 2013 (Lower 48 States)



Source: EIA 914 data (January 2013 published in April 2013)

Liquid natural gas (LNG) arbitrage

The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – rose in March and is at a very significant premium to the US gas price ($11.50 versus $4.10). LNG supplies to the UK have been somewhat constrained, particularly in light of strong demand for LNG to Asian markets. This, together with a prolonged European winter, has been helping to support the price in recent months. US LNG imports remained well below 1 Bcf/day in March as cargoes took advantage of the higher prices in Europe and Asia.

Canadian imports into the US

Net Canadian imports of gas into the US dropped from 9.1 Bcf/day in 2007 to 5.4 Bcf/day (estimated) in 2012. This was initially driven by falling rig counts and a less attractive royalty regime enacted in 2007 and has accelerated due to increased domestic demand from Canadian oil sands development. Although the Canadian rig count has recovered somewhat, we expect net imports to continue to decline in 2013 to around 5 Bcf/day.

Demand Outlook

Our focus is on how gas demand is likely to look for 2013. We expect demand from power generation to be down on 2012 (a reversal of much of the 2012 coal to gas switching if the gas price stays above $3) but about 1-1.5 Bcf/day above 2011. Residential and commercial gas demand will, as ever, be weather dependent, but assuming average temperatures, demand should be around 2 Bcf/day better than 2012 and unchanged from 2011. And we expect industrial consumption about 0.3 Bcf/day above 2012. Overall, assuming average weather, we expect 2013 demand to be around 71-72 Bcf/day, down a little on 2012 but around 2.5-3 Bcf/day higher than 2011.

Looking out further, the low US gas price has stimulated various initiatives that are likely to have a material impact on demand from 2015/16 onwards. The most significant is the group of LNG export terminals in the US and Canada which are in the planning/early construction stages. There are over 26 bcf/day of LNG export projects proposed in the US today, plus a further 6 bcf/day in Canada, as shown below:

Source: Bernstein (December 2012)

#	Terminal	Sponsor	MTPA Capacity	BCF/day Capacity
US – Approved				
1	Sabine Pass	Cheniere	16.0	2.6
US – FERC Review				
2	Freeport	Freeport	10.0	1.8
3	Corpus Christi	Cheniere	13.5	1.8
4	Coos Bay	Jordan Cove	6.0	0.9
5	Lake Charles	ETE-BG	7.0	2.4
6	Hackberry (Cam)	Sempra	12.0	1.7
7	Cove Point	Dominion Res.	7.2	1.0
8	Astoria	Oregon LNG	8.0	1.3
US – Proposed				
9	Alaska LNG	XOM-BP-COP	15.0	3.0
10	Brownsville	Gulf Coast LNG	20.6	2.8
11	Pascagoula	Gulf LNG	9.0	1.5
12	Lavaca Bay	Excelerate	8.5	1.4
13	Elba Island	ETE	3.0	0.5
14	Golden Pass	XOM	16.0	2.6
15	Plaquemines Parish	CE FLNG	7.5	1.1
	US Total		**159.3**	**26.4**
Canada – Review				
16	Kitimat	EOG-APA-ECA	5.5	0.7
17	BC LNG	Var.	1.8	0.3
18	LNG Canada	RDS	24.0	3.6
Canada – Proposed				
19	Prince Rupert	Petronas	8.5	1.0
20	Ridley Island	BG	8.5	1.0
	Canada Total		**48.3**	**6.6**

Not all these facilities will be built but we think that exports of between 6-10 bcf/day from the US by 2020, or around 10-15% of new demand, are likely. Additional LNG exports from Canada will contribute a few extra bcf, tightening the natural gas balance across North America. Importantly, the Department of Energy (DoE)-sponsored report concluded that LNG exports will have a net benefit to the US economy and that benefits are likely to increase as LNG exports rise.

Industrial demand will also grow thanks to the construction of new petrochemical plants: Dow Chemical and Chevron Phillips have large new Gulf Coast facilities planned for 2017, the first new crackers to be built in the US since 2001.

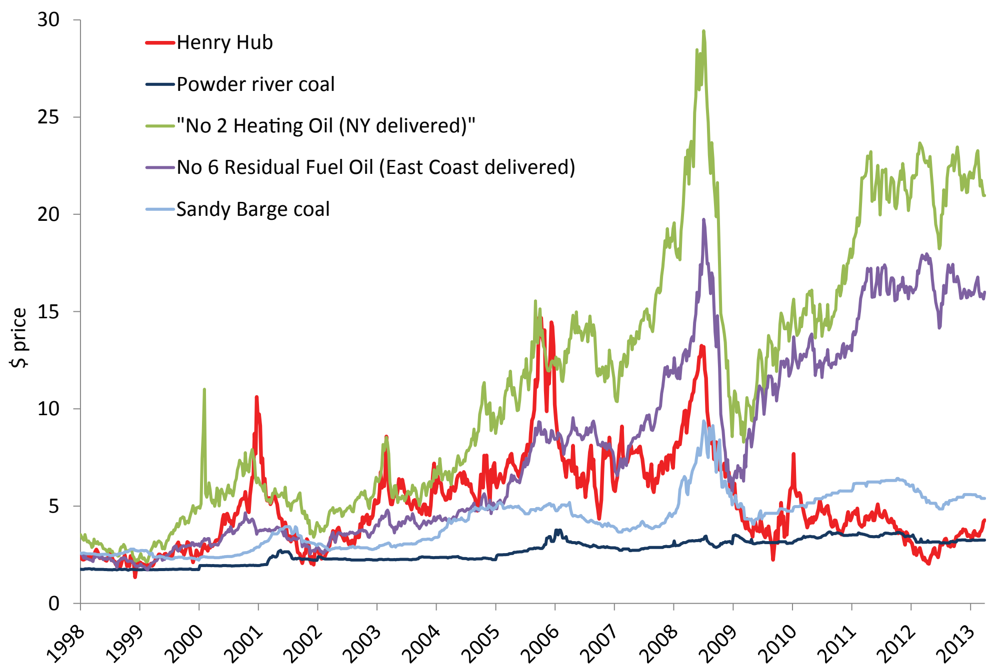
We believe that gas will continue to take the majority of incremental power generation growth in the US. The combined cycle gas turbine fleet (CCGT) operated in 2010 at 39% of capacity versus the coal fleet at 70% of capacity. 2012 has given us a glimpse of the scale of switching that is possible, and while the CCGT fleet will not reach 70% anytime soon (it is not all in the 'right place' geographically), we do expect it to grow its underlying market share and add several Bcf/day to gas demand over the next few years. Our working assumption is 1 Bcf/day per year.

We also watch with interest the efforts being made to increase the usage of LPG and LNG by the US truck, bus and delivery van fleets. Whether this will gain traction is hard to know. If it does its impact will be meaningful. If the entire fleet described above moved to gas, we estimate that it would increase demand by 18 Bcf/day. A much smaller transport market but one that might be easier to convert is the US railways. BNSF Railway announced in March 2013 that they would trial a switch for their train engines from diesel to liquefied natural gas. BNSF Railway is the US's second largest freight railroad network. Rail engines in the US currently consume around 0.25m b/day of distillate, equivalent to around 1.5 Bcf/day of gas.

Other

Relationship between gas price and other energy commodity prices in the US
The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of 23.7x at the end of March continues well outside the more normal ratio of 6-9x. If the oil price averages around $90 in 2013 and the relationship between the oil and gas price returning to its longer-term average of 6-9x, this would imply the gas price increasing back to above $10 once the gas market has returned to balance. This is quite a thought and a long way away from current market sentiment.
The following chart of the front month US natural gas price against heating oil (No 2), residual fuel oil (No 6) and coal (Sandy Barge adjusted for transport and environmental costs) seeks to illustrate how coal and residual fuel oil switching provide a floor and heating oil a ceiling to the natural gas price. With the gas price trading below the coal price support level for the first 8 months of 2012, resulting coal to gas switching for power generation was significant. It will be interesting to see how much of the switching persists in 2013 with gas back above $3.50/Mcf – some but not all, we think.
e $3/Mcf – some but not all, we think.

Figure 11: Natural gas versus substitutes (fuel oil and coal)
Henry Hub vs. residual fuel oil, heating oil, Sandy Barge (adjusted) and Powder River coal (adjusted)



Source: Bloomberg LP (March 31. 2013)

Conclusions about US natural gas

The US natural gas price bottomed in 2012 and the recovery has begun. Natural gas at around $4 spot is over double the April 2012 low but still below the (full cycle) marginal cost of supply and as the depressed rig count holds back new supply we expect the price to recover further. We believe the gas price may then be held around the $4-5 range for a period until demand grows further, and longer term we expect the price to normalize to $6-8.

6. Appendix: Oil and Gas markets historical context

Figure 12: Oil price (WTI $) last 23 years.

Source: Bloomberg

For the oil market, the period since the Iraq Kuwait war (1990/91) can be divided into two distinct periods: the first 9-year period was broadly characterized by decline. The oil price steadily weakened 1991 - 1993, rallied between 1994 –1996, and then sold off sharply, to test 20 year lows in late 1998. This latter decline was partly induced by a sharp contraction in demand growth from Asia, associated with the Asian crisis, partly by a rapid recovery in Iraq exports after the UN Oil for food deal, and partly by a perceived lack of discipline at OPEC in coping with these developments.

The last 13 years, by contrast, have seen a much stronger price and upward trend. There was a very strong rally between 1999 and 2000 as OPEC implemented 4m b/day of production cuts. It was followed by a period of weakness caused by the rollback of these cuts, coinciding with the world economic slowdown, which reduced demand growth and a recovery in Russian exports from depressed levels in the mid 90's that increased supply. OPEC responded rapidly to this during 2001 and reintroduced production cuts that stabilized the market relatively quickly by the end of 2001.

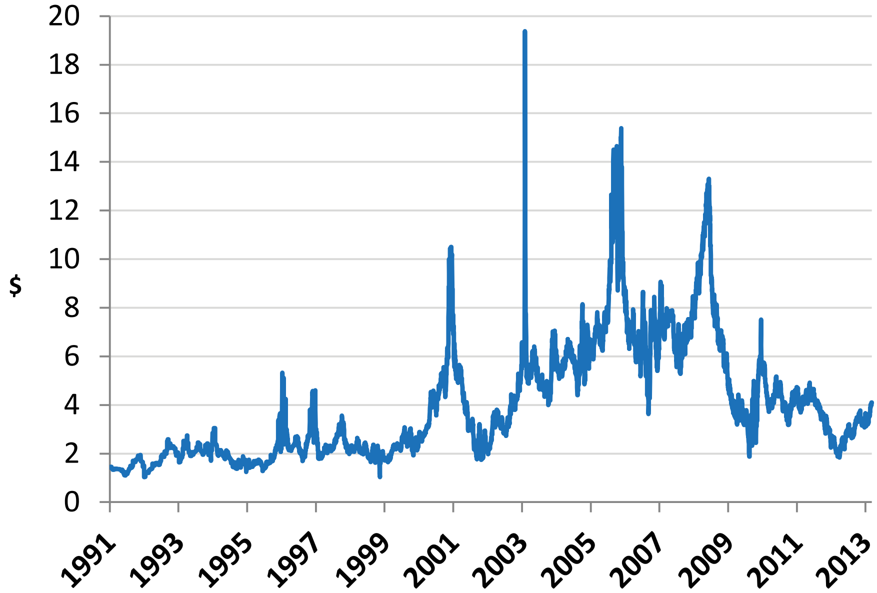
Then, in late 2002 early 2003, war in Iraq and a general strike in Venezuela caused the price to spike upward. This was quickly followed by a sharp sell-off due to the swift capture of Iraq's Southern oil fields by Allied Forces and expectation that they would win easily. Then higher prices were generated when the anticipated recovery in Iraq production was slow to materialise. This was in mid to end 2003 followed by a much more normal phase with positive factors (China demand; Venezuelan production difficulties; strong world economy) balanced against negative ones (Iraq back to 2.5 m b/day; 2Q seasonal demand weakness) with stock levels and speculative activity needing to be monitored closely. OPEC's management skills appeared likely to be the critical determinant in this environment.

By mid-2004 the market had become unsettled by the deteriorating security situation in Iraq and Saudi Arabia and increasingly impressed by the regular upgrades in IEA forecasts of near record world oil demand growth in 2004 caused by a triple demand shock from strong demand simultaneously from China; the developed world (esp. USA) and Asia ex China. Higher production by OPEC has been one response and there was for a period some worry that this, if not curbed, together with demand and supply responses to higher prices, would cause an oil price sell off. Offsetting this has been an opposite worry that non OPEC production could be within a decade of peaking; a growing view that OPEC would defend $50 oil vigorously; upwards pressure on inventory levels from a move from JIT (just in time) to JIC (just in case); and pressure on futures markets from commodity fund investors.

After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita which devastated New Orleans caused oil to spike up to $70 in August 2005, and it spiked up again in July 2006 to $78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East. OPEC implemented cuts in late 2006 and early 2007 of 1.7 million barrels per day to defend $50 oil and with non-OPEC supply growth at best anaemic demonstrated that it could to act a price-setter in the market at least so far as putting a floor under it.

Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse of Lehman Brothers and the financial crisis and recession that followed, all of which contributed to the oil price falling back by early 2009 to just above $30. OPEC's responded decisively and reduced output, helping the price to recover in 2009 and stabilise in the $70-95 range where it remained for two years. Since 2011 we have seen a disconnect between the WTI and Brent oil benchmarks due to US domestic oversupply affecting WTI. The WTI price has generally moved up and into a wider range of $80-$110, whilst Brent's trading range over the same period has been higher, at $90-$125, with the pressures of non-OECD demand persistently outstripping non-OPEC supply and supply tensions in the Middle East/North Africa prevailing.

Figure 13: North American gas price last 22 years (Henry Hub $/Mcf)



Source: Bloomberg

With regard to the US natural gas market, the price traded between $1.50 and $3/Mcf for the period 1991 - 1999. The 2000s were a more volatile period for the gas price, with several spikes over $8/mcf, but each lasting less than 12 months. On each occasion, the price spike induced a spurt of drilling which brought the price back down. Excepting these spikes, from 2004 to 2008, the price generally traded in the $5-8 range. Since 2008, the price has averaged below $4 as progress achieved in 2007-8 in developing shale plays boosted supply while the 2008-09 recession cut demand. Demand has been recovering since 2009 but this has been outpaced by continued growth in onshore production.

North American gas prices are important to many E&P companies. In the short-term, they do not necessarily move in line with the oil price, as the gas market is essentially a local one. (In theory 6 Mcf of gas is equivalent to 1 barrel of oil so $60 per barrel equals $10/Mcf gas). It remains a regional market more than a global market because the infrastructure to export LNG from North America is not yet in place.

Tim Guinness
Chairman & Chief Investment Officer

Will Riley & Ian Mortimer
Fund investment team

Commentary for our views on Alternative Energy and Asia markets is available on our website. Please click here to view.

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Earnings per share (EPS) is calculated by taking the total earnings divided by the number of shares outstanding.

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