GUINNESS ATKINSON FUNDS

Energy brief

Tim Guinness

January 2013

Commentary and Review by portfolio manager Tim Guinness

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REPORT HIGHLIGHTS

FUND NEWS

• *Fund size $91 million at end of December*

OIL

• ***WTI/Brent finishes month stronger/unchanged at $92/112***

WTI $89 and Brent $112 at start of month; end at $92 and $112. The Brent-WTI spread narrows slightly to $20. OECD oil inventories fell in November (latest data), following the seasonal trend.

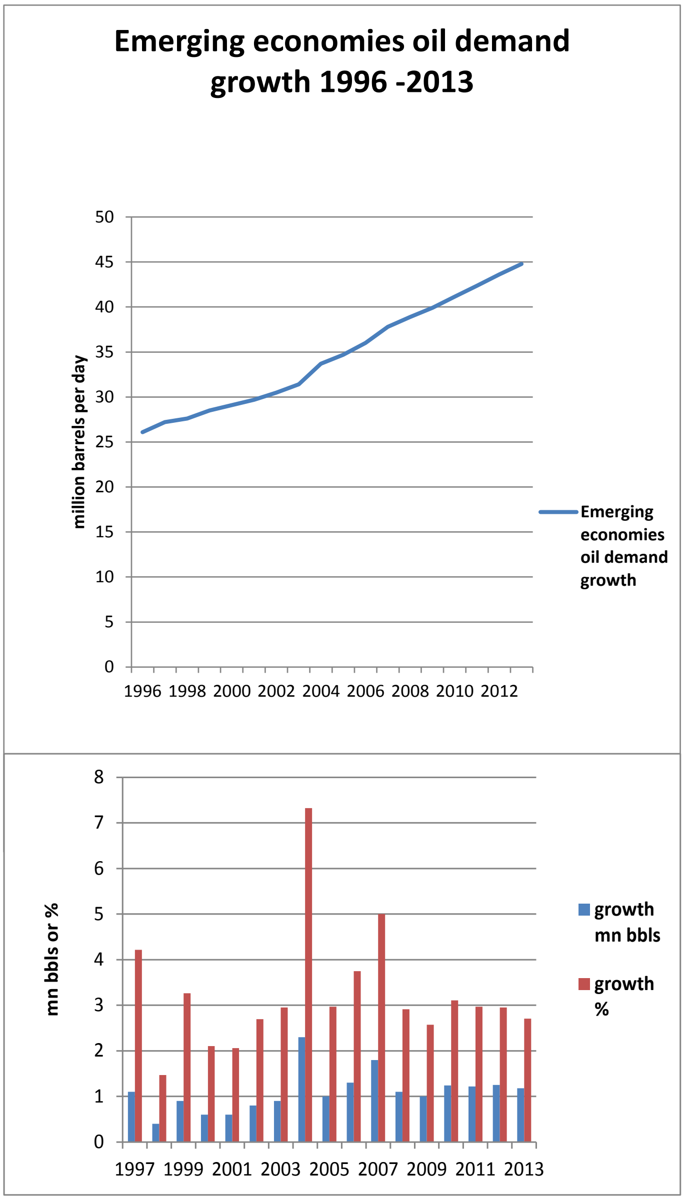
NATURAL GAS

• ***US gas price essentially flat over the month.***

Henry Hub spot traded between $3.15 and $3.48 per Mcf (1000 cubic feet), ending at $3.44 (up from April low of $1.84).

Chart of the month:

Emerging Economy oil demand growth carrying on at around 3% per annum (pa) - hardly slowed in 2012

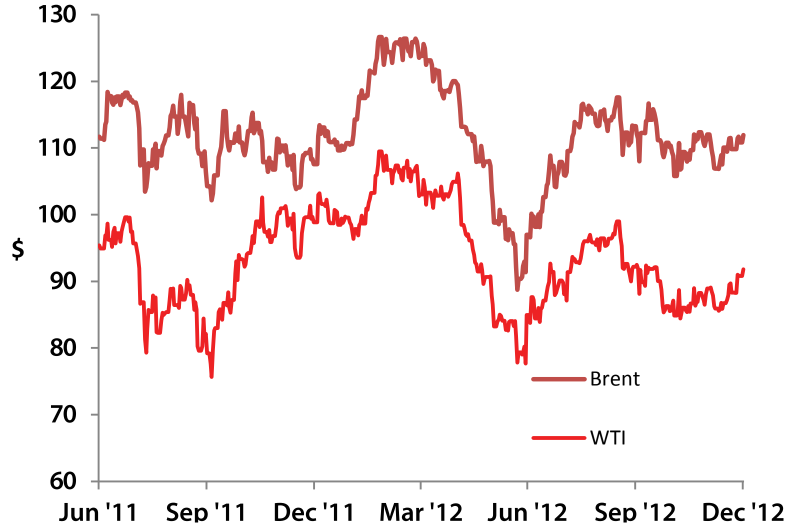


Source: IEA

1. December 2012 Review

Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months June 30, 2011 to December 31, 2012



Source: Bloomberg

The West Texas Intermediate (WTI) oil price opened the month at $88.91, then reached a low for the month on December 10 of $85.56. It traded up to end the month at a month high of $91.82. In 2012, WTI averaged $94.12. As a reminder, WTI averaged $95.04 in 2011.

Brent fell slightly in the month, from $112.01 to $111.94. The gap between the WTI and Brent benchmark oil prices that started at the beginning of 2011 contracted slightly from $23 to $20 at the end of December. The Seaway pipeline reversal that started flowing during May began to relieve the Cushing bottleneck, but the current lack of takeaway pipelines to deal with growing Permian, Bakken and other in-land US oil supply growth will persist until further capacity is in place. Seaway is due to expand in January 2013 by 250,000 barrels/day (b/day) and by a further 450,000 b/day in 2014. It is not clear if this will be enough.

Factors which strengthened the WTI oil price in December:

- **Iran crisis** - Iranian production (per Bloomberg data) remained roughly flat in December but remains down 0.9m b/day (-26%) from levels a year ago. The decline is a result of US and European sanctions against Iranian oil imports; the European sanctions formally started on July 1 but were already having an effect before that date. Previously, Iranian production data has been subject to a number of revisions, so the exact picture seems difficult to pinpoint, but the sanctions do seem to have a material effect.

- **Iraq supply** - Oil exports from Iraq's Kurdistan region were halted on December 22 following disagreements between the Kurds and the Iraqi central government over energy contracts terms. Earlier in December, exports were at 180,000 b/day, but dropped (before being stopped) to 6,000 barrels. Iraq production (per Bloomberg data) fell slightly in December by 0.1m b/day (1%), and we wait to see if a further fall is reflected in the January data.

- **Organization for Economic Co-operation & Development (OECD) inventory levels**

OECD oil inventories fell in November by 19m barrels, versus a five year average draw in November of 8 million barrels. Overall, inventories levels remain reasonably tight, and Saudi's recent over-production does not appear to be showing up in inventories.

Factors which weakened the WTI oil price in December:

- **Saudi Arabia and OPEC -11 ex Iran high level of oil production**

Saudi, United Arab Emirates (UAE), Kuwait and Qatar production is running 2.09m b/day above its level two years ago. We continue to hold the view that this group of countries are trying to push prices lower; in particular, to exert downward pressure on Iran's oil revenues and to achieve a political compromise that avoids military action by Israel. Sanctions are less likely to work while oil is well over $100/barrel (bbl). We believe there are two other, subsidiary reasons for high levels of output: one, Saudi think it advisable to "show support" to President Obama, given the Syrian crisis on its doorstep, and two, Saudi realize that too high an oil price is not in its long term interest.

- **US demand fears**

As in November, fears about the health and future prospects for the global economy weighed heavily on sentiment surrounding oil demand. In particular, markets focussed on negotiations surrounding the US fiscal cliff – a combination of tax increases and spending cuts due to take effect in 2013. Sentiment ranged from optimism to pessimism as the negotiations progressed, and a deal was eventually reached early in 2013.

- **US production growth forecasts**

US grew liquids output from 8.1m b/day to 9.0m b/day in 2012, and the International Energy Agency (IEA) is projecting growth to 9.6m b/day in 2013. This growth of 0.6m b/day represents the majority of total non-Organization of Petroleum Exporting Countries (OPEC) supply growth in 2013, estimated at 0.9m b/day. The sharp rise in production from shale oil has been the main driver behind growth in North American output, as new techniques, such as fracking and horizontal drilling, are used to extract oil from areas such as the Bakken and the Eagleford.

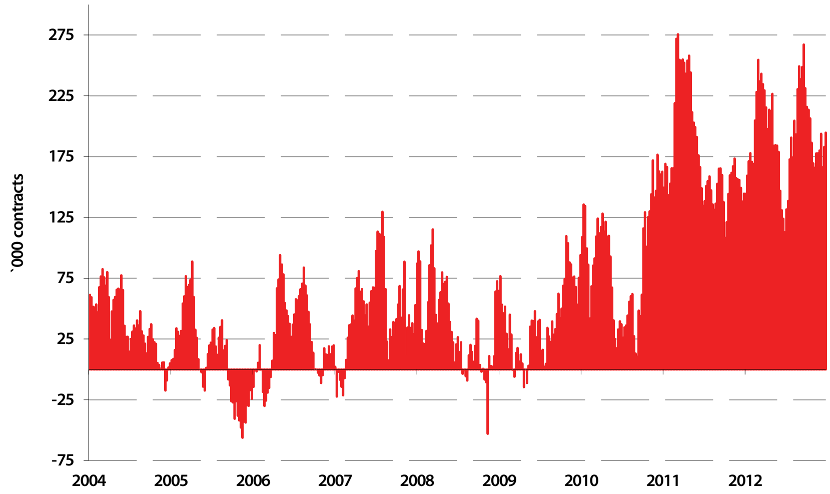
- **Strong production in Iraq**

Iraq production is at 3.3m b/day – up 0.915m b/day versus two years ago.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position rose during December, albeit to a level much lower than the high for 2012 reached in September. It started the month at 180,000 contracts long and increased to finish the month at 195,000 contracts. Though the index reached higher levels in 2011, its current level is still high when compared with recent years.

Figure 2: NYMEX Non-commercial net futures contracts: WTI January 2004 – December 2012



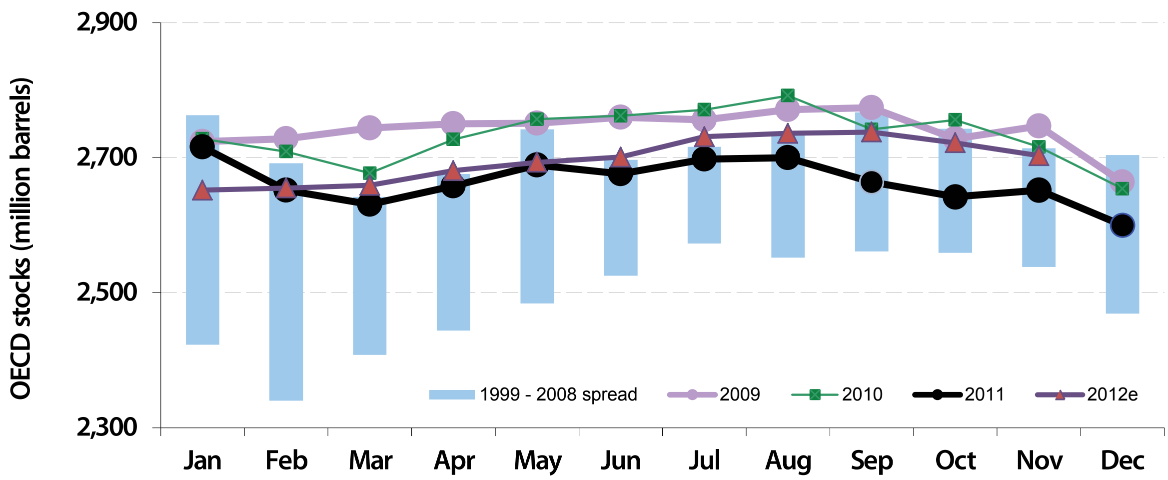
Source: Bloomberg/Nymex (January 2012)

OECD stocks

OECD estimated total crude and product stocks for November 2012 (published in the December 2012 IEA Oil Market Report) declined by 19 million barrels from 2,722 million barrels, giving a total stock of 2,703 million barrels. Over the preceding 5 years, the average inventory draw in November is 8 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. This tightening happened even as OPEC-12 production increased to make up for lost Libyan and then Iran production, and the IEA released 60 million barrels of emergency reserve oil. Since January 2011, OECD inventories have mostly remained within the high-low spread of 1998-2009. Despite Saudi's attempts to loosen the market, its over-production does not appear to be showing up in inventories – figures for recent months are well-behaved, falling within the 1999-2008 range.

Figure 3: OECD total product and crude inventories, monthly, 1998 to 2012



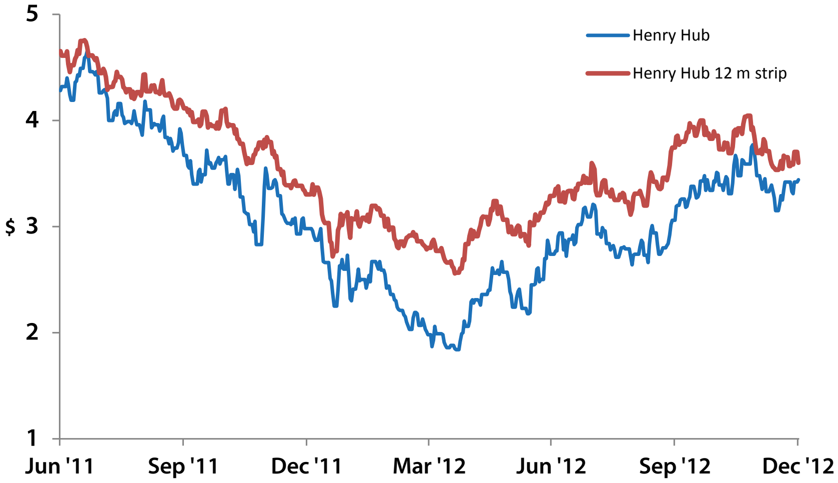
Source: IEA Oil Market Report (December 2012); Guinness Asset Management estimates

Natural Gas Market

The US spot natural gas price (Henry Hub) opened December at $3.48 per Mcf (1000 cubic feet) and, after falling to $3.15 mid-month, rallied well to close the month at $3.44. The spot gas price hit a low of $1.84 in April and averaged $2.75 in 2012, 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) declined over the month from $3.69 to $3.60 (having risen over $4 in the middle of November). The strip price averaged $3.28 in 2012 having averaged $4.35 in 2011, $4.86 in 2010 and $5.25 in 2009.

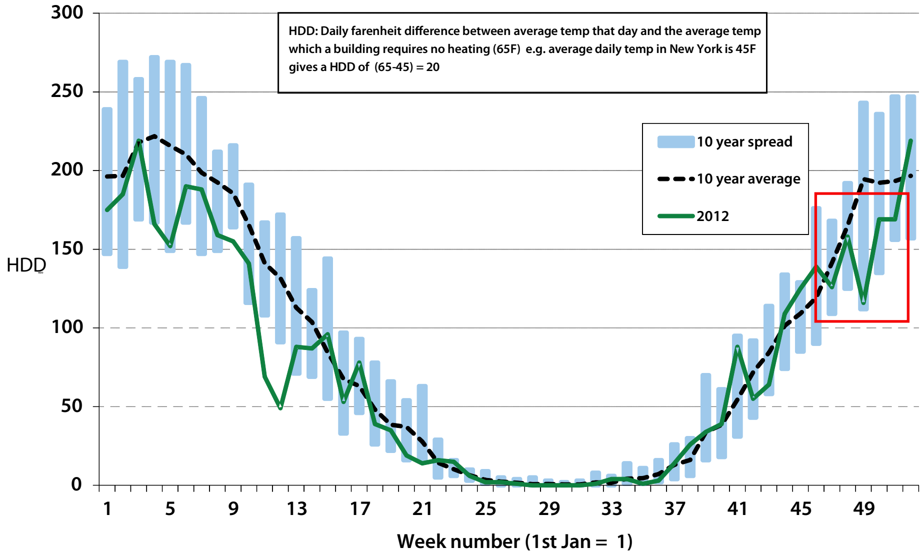
Figure 4: Henry Hub Gas spot price and 12m strip ($/Mcf) June 30, 2011 to December 31, 2012



Source: Bloomberg

Factors which strengthened the US gas price in December included:

- **Very warm first three weeks of December** - The spot gas price declined by 9% over the first half of December as unusually warm weather reduced heating demand for gas. The weather over this period was 22% warmer than the 10 year average, as illustrated by the chart of heating degree days (a measure of temperatures across the US) below. At this time of year, heating demand is a dominant component of overall gas demand, therefore, weather can have a large effect.



- **Storage levels**

Weak heating demand caused by the very warm December weather in turn led to a smaller decline in the amount of gas in storage compared to the seasonal average. Gas in storage at the end of November was 150 billion cubic feet (bcf) over the 5 year average, and ended this month 361 bcf above the 5 year average at 3,517 bcf (versus the 5 year average of 3,156 bcf).

- **US production data**

The October data (latest available) from the Energy Information Agency indicated that total US natural gas production was up 0.3 Bcf/day (0.4%) month-on-month. The rise was entirely accounted for by the recovery in Gulf of Mexico production following Hurricane Isaac. On shore production was marginally down. Marcellus continues to grow, but this was matched by the declines in Texas and elsewhere.

Factors which weakened the US gas price in December included:

- **Cold weather at the end of December**

The spot gas price recovered from its low of $3.15 on December 14 to finish the month at $3.44 thanks mainly to the return of colder weather, which caused a rise in heating demand and consequently a larger than average withdrawal of gas from storage.

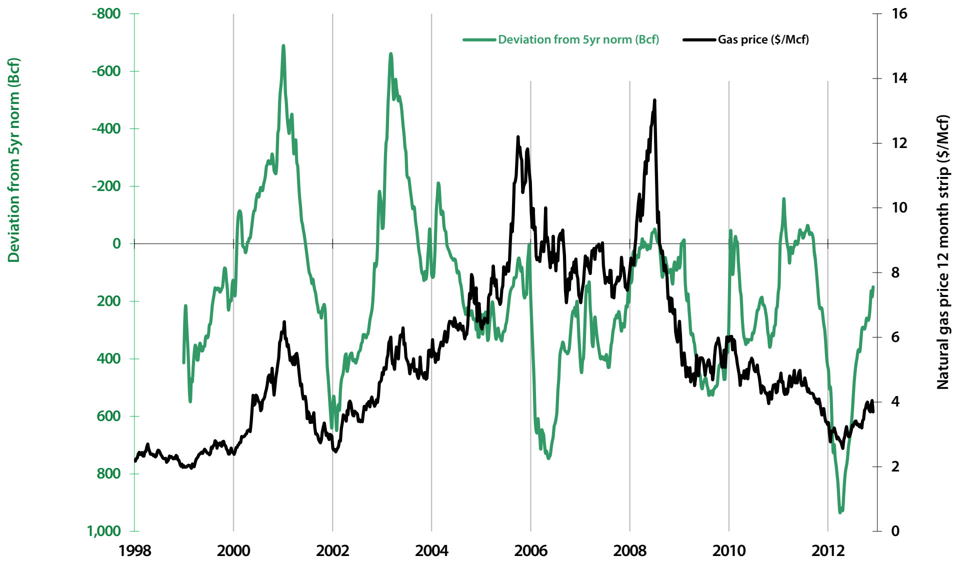
- **Low gas drilling rig count**

The US natural gas-directed rig count (reported by Baker Hughes) rose slightly from 424 to 431 rigs during December, but since the end of September 2011, has declined from 923 rigs (i.e. by 53%). 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 likely to be a reasonable lead time between a fall in the rig count and a fall in production but the cumulative effects of the slide which started 12 months ago can only grow for as long as the rate falls.

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



Source: Bloomberg, EIA (January 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 last 12 months have been characterized by oversupply for the first half and undersupply since March. Thus, a 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 to around $3.50 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.

2. Manager's Comments

First, we would like to wish all our investors a very happy and prosperous New Year!

Second, we want to share with you some big picture thoughts: what happened in 2012 that we can learn from, and what might the next 12 months hold for us as investors in and interested observers of the energy investment space? First, **the big developments in 2012** –

Oil. Both Brent and WTI price were firmer than we expected. Brent averaged $111.63 in 2012 versus $111.26 in 2011. WTI averaged $94.05 in 2012 versus $94.88 in 2011. The average spread between Brent and WTI widened slightly from $16.38 to 17.53.

US onshore oil production grew strongly. Total US oil field production has now grown by close to 2m barrels/day from 5m b/day to 7 m b/day since 2008, with 1.13m b/day of oil field production growth occurring in 2012. The drivers were the Bakken, Eagleford and Permian basins. The former, in particular, responded well to horizontal drilling and hydraulic fracturing activity. Across the three basins the rig count rose sharply from 302 at the end of 2009 to 830 at the end of 2012.

US Refineries boomed, partly because the US balance of trade in refined petroleum products has been transformed by strength in demand from Latin American booming emerging economies. In 2008 the US was a net importer of 1.8m b/day of product; in 2012 it exported 0.8m b/day. This swing in trade has more than compensated for the drop in domestic demand over the same period of 2.5 b/day. And partly refining margins have been further boosted at those refineries able to benefit from the opening up of the WTI discount to Brent.

Other non OPEC oil production declined by close to 0.5m b/day, which almost exactly mirrored the decline in Syria, Yemen and Sudan. In the rest of non OPEC Canada growth of 0.25 m b/day Russia 0.13 m b/day and China 0.05 m b/day was matched by equal declines elsewhere from mature basins including 0.29 m b/day in the North Sea.

OPEC ex IRAN saw Libya recover from 0.7 m b/day to 1.54 m b/day – almost its pre Arab spring level; and Iraq grew production from 2.7m b/day to 3.3 m b/day, nearing its previous 1979 peak at 3.5 m

Iran's production was hit by sanctions and fell by some 0.9 m b/day.

And yet OPEC inventories did not rise significantly. At the end of October (latest data point) they were only 2% ahead of a year ago.

What lies behind this is continuing, robust emerging economy demand. This is the yin to the growing shale oil production yang. We think commentators are overly focussed on the prospect of US "energy independence" (by the way, energy not oil) – which we do not deny is perfectly plausible if liquefied natural gas (LNG) and coal exports grow enough. But this is just like the development of the Gulf of Mexico and North Sea and Alaska in the 1980s in response to the 1970s price hike with, however, one huge difference. Back then, oil demand from the OECD economies had exploded 1950 -73, and they were at the end of a 25 year journey adopting the motor vehicle; impetus was fading and demand naturally then corrected as prices jumped. Now, however, the picture is different. China's demand for oil per capita has not yet even reached that of the OECD at the beginning of the 1950s. There are two decades of unrelenting oil demand growth to come while the Chinese vehicle fleet potentially moves from 100 million cars now to 400 million by 2030, with India and several other developing economies possibly following about 10 years behind. Another difference is that OPEC and Russia are much happier to work together now than then, and between them they control 48m out of 91m b/day of production – 53%!

Looking 10 years forward to 2022 we see the potential for 10 to 13m b/day of global demand growth (emerging economies 12 – 15m b/day less 2 m b/day OECD decline) and muted supply growth (US 2m b/day; Iraq 2m b/day; Africa 2m b/day; Brazil 1.75m b/day; Canada 1.25 m b/day; Caspian 1 m b/day) less mature basin declines). If you doubt us, remember that, for example, Canada only grew its oil production by 0.9m b/day from 2002 to 2012 notwithstanding all the effort to develop its oil sands.

Natural Gas. The US saw its very capitalist free-wheeling competitive industry enjoy (!) a classic bust following the 2007 boom. Gas prices peaked in 2007 at over $15 per mcf and troughed in March 2012 at under $2.

For 7 years onshore gas production has grown from circa 45 bcf/day to circa 68 bcf /day following the technological discovery of how to drill horizontally and frack in a way that released gas from its reservoirs. This growth equates simplistically to 23 bcf /day or circa 3 – 4 bcf/day of growth per year. As noted in a later section, this was absorbed for the first 5 years by a combination of demand growth, declining Canada imports, reduced LNG imports and declining Gulf of Mexico production. Eventually (September 2011) the ability to absorb the growth was overwhelmed (helped too by a very warm winter). Since then, the industry has reacted in classic fashion – the gas rig count has been halved and coal plants started switching to gas (now the cheapest fuel) as gas moved below c$3.50/mcf. We know this will rebalance the market. It's how markets have worked. The only issue is when. So far, two thirds of the massive overhang has been worked off in about 9 months.

Outside the US gas prices 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% pa since 2000 and having now reached 10 bcf/day (one seventh 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 growing its gas demand 4X in the next 10 years.

By 2022 we expect demand to be 40 bcf/day. Globally demand - now 315 bcf/day - will rise to 450 bcf/day by the same date if the last 10 years are repeated (4.4% pa developing world; 0.8% pa growth developed world).

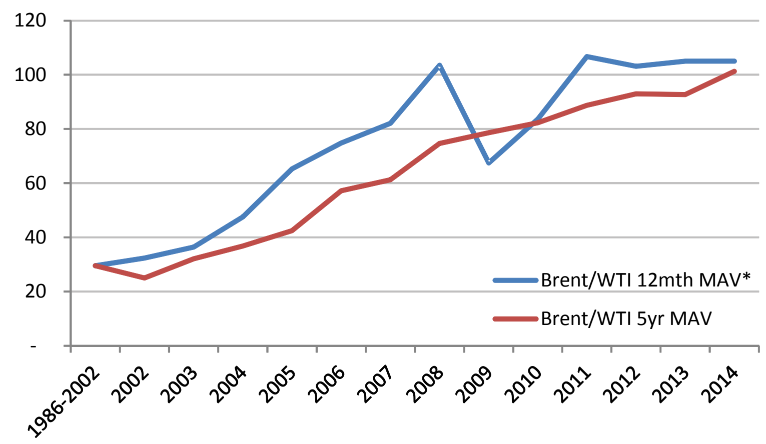
What does the future hold?

Oil - For many months we have commented that Saudi, the UAE and Kuwait stood at center stage of the oil market. That continues to be our view. We also think that they would likely manage whatever the US, China or Eurozone economies threw at them. However, we increasingly feel we have been over cautious as to what would transpire. We saw the average of Brent and WTI oil price settling back to trade in an $80 – 110 averaging around $95, with Brent at $100 and WTI at $90 and the two prices slowly converging. We now feel that Brent may average $110 from here on and WTI $100, and the likely average of the two will be $105. Inflation is doing its stuff. Global GDP is now circa $74 trillion. We will likely consume 90.6m b/day of oil in 2013. At $105 that spend is $33.1bn or 4.44% of 2013 Global GDP, assuming growth and inflation add 6% to GDP. As some of you who know me will have heard me say – history shows that when prices take the spend on oil to 7-8% pa it never lasts; and 2% of GDP is cheap. Over 4% of GDP has been what we've paid for oil in 15 of the last 40 years. It will not bring the world economy to a grinding halt. It's a price that from OPEC's point of view looks fair. They will strive to achieve it. And it will likely rise from here gradually at something like inflation or better.

Our more positive view is influenced by the fact that we feel that the recovery in the US economy (which we believe is real) will not be derailed by the February 28th fiscal cliff mark 2 and that China will now rebuild momentum. The latter is a more adventurous view, but all our recent prodding of the data leaves us to conclude that China will surprise the doubting western commentators by successfully handing the economic baton from infrastructure investment to consumption of cars and consumer goods -white goods; electronics; services – and yes, the growth rate will likely slow to maybe 5% pa, maybe 3% pa, but this should continue to be a period of great prosperity and growth. Japan grew at 8.2% pa from 1950 to 1970, and then grew at 3.3% pa from 1970 to 1990. We see China similar to where Japan was at 1965. The two remaining black clouds are the OECD governments over indebtedness and Europe. But even here we see green shoots. Reality is dawning among the political classes. Bullets must and are going to be bitten. European recovery may not come till 2015, but remember that the current slump in car sales, for example, has the possible silver lining of a business cycle recovery in 2 years' time. Nor do property slumps last forever. We may need interest rates to get back to normal before they do, however. Some politicians don't get it – but one of the biggest depressants hanging over the economy is the fear of what may happen when interest rates are allowed to rise. The answer of course is that some businesses may be tipped over the edge, but most businesses have been cutting their cloth for this day and will get through. And we need the creative destruction of those that fail to happen.

As in the last few monthly comments, I show below our view in the context of the recent past using inflation adjusted oil prices.

Oil price – last decade (real terms)



Oil Price (inflation adjusted)													fcst	
12mth 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	100	100
Brent	30	32	35	46	64	75	82	103	67	84	115	112	110	110
Brent/WTI 12mth MAV	30	32	36	48	65	75	82	103	67	84	107	103	105	105
Brent/WTI 5yr MAV	30	25	32	37	42	57	61	75	79	82	89	93	93	101

Source: Bloomberg USCRWTIC & EUCRBRDT. 2012 Jan – Dec actual; fcst Guinness Aset Management

*MAV – Moving Average

Gas - As made clear above, we see the global gas market as strong. As for the US - the US is weak just now. But our hunch is that in 3 years the gas price will likely 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% up on the $3.50 today and 118% up on 2012 average price of gas of $2.75.

Energy equities - It is not difficult to work out that with many energy equities on single digit PERs, they are likely to perform strongly in this scenario. Of course, we may be wrong. But sometimes we are right, too. The recent 18 months have seen a big underperformance by energy equities relative to the broad market. Maybe this year we will see a stealth rally in the sector. What goes down comes up, and vice versa. I think the last 18 months were influenced by a view that the commodity super-cycle is over. I think we need to hold on a minute. The more likely evolution of the commodity cycle is that the demand for infrastructure commodities – copper, aluminium, iron ore – may well level off and prices weaken as capacity moves from tight to loose. But historically, the next stage of the cycle was that commodities in growing demand from consumers continued to remain firm and even strengthened further. Here we are talking about commodities such as energy and agricultural commodities.

Energy equity valuations - The Fund, based on consensus estimates, is on a 2012 P/E ratio of 10x at December 31, 2012 (2010 pre Libya/Iran crises P/E 9.5x), which is well below the broad market's 14.3x (S&P500 at 1,426 with 2012 forecast EPS of $99.5). Because we are mindful that oil could weaken and gas recover, a Fund P/E which looks back at 2010 earnings (when oil averaged $79 and Henry Hub Gas $4.36), giving a PE of 9.5x versus S&P 2012 of 14.3x, gives another way of analyzing current value, in our view. The discount (based on 2010 earnings) is 34%, giving a potential upside versus the broad market of 51% when energy P/Es close the gap with the broad market; history indicates they'll close the gap when the current oil price and long-run market expectations for the oil price come together. The chart above says to us that $100 oil is around where that could happen. This represents a little bit more than tripling in the real oil price from the cheap oil 1985-2002 period.

The super-majors, to our way of thinking, are not expensive, and non-majors have become increasingly good value thanks both to their underperformance of the broad market over the past 18 months. 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. Suffice it to say this is, in our view, what is increasingly likely to occur.

Interestingly, energy stocks which underperformed the S&P500 from end March 2011 to June 26, 2012 by 22.14% have started to recover relatively since then to end December 2012 clawing back 3.79%.
Energy equities are one of the better inflation hedges. If we see dollar inflation of 30/50% over the next decade it would be surprising if oil and gas prices do not rise by a comparable percentage over that time-frame.

3. Performance – Guinness Atkinson Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was down by 1.38% in November. The S&P 500 was up by 0.57% over the same period. The Fund was down by 2.53% over this period, underperforming the MSCI World Energy Index by 1.15% (all in US dollar terms).

Within the Fund, November's stronger performers were Unit, Valero, Patterson, JA Solar and Soco. Poorer performers were Trina Solar, Bill Barrett, Carrizo, Chesapeake and Stone.

Performance as of December 31, 2012

Inception date 6/30/04	Full Year 2009	Full Year 2010	1 year (annualized)	Last 2 years (annualized)	Last 5 years (annualized)	Inception to end 2011 (annualized)	Since Inception (annualized)
Global Energy Fund	63.27%	16.63%	3.43%	-5.21%	-2.53%	13.24%	12.19%
MSCI World Energy Index	26.98%	12.73%	2.52%	1.62%	-1.63%	10.45%	9.51%
S&P 500 Index	26.47%	15.06%	15.89%	8.80%	1.66%	3.60%	4.81%

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/performance.asp 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.

4. Portfolio – Guinness Atkinson Global Energy Fund

Buys/Sells

There were no buys or sells in December.

Sector Breakdown

The following table shows the asset allocation of the Fund at December 31, 2012.
recent times.

(%)	31 Dec 2007	31 Dec 2008	31 Dec 2009	31 Dec 2010	31 Dec 2011	31 Dec 2012	*Change YTD*
Oil & Gas	**103.5**	**96.4**	**96.1**	**93.2**	**98.5**	**98.6**	***0.1***
Integrated	66.2	53.7	47.2	41.2	39.6	39.1	*-0.5*
Exploration and production	25.8	28.7	32.0	36.9	41.5	41.6	*0.1*
Drilling	8.1	5.2	8.4	6.3	6.0	7.4	*1.4*
Equipment and services	3.4	6.4	5.4	5.3	6.6	7.1	*0.5*
Refining and marketing	0.0	2.4	3.1	3.5	4.8	3.4	*-1.4*
Coal and consumables	**2.5**	**2.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Solar	**0.0**	**0.0**	**0.0**	**3.2**	**1.2**	**1.2**	**0.0**
Construction and engineering	**0.0**	**0.4**	**0.4**	**0.4**	**0.4**	**0.6**	**0.2**
Cash	**-6.0**	**0.9**	**3.5**	**3.2**	**-0.1**	**-0.4**	**-0.3**
Total	**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 **December 31, 2012** was on an average price to earnings ratio (PE) versus the S&P 500 Index at 1,426, 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 $99.5 for 2012). This is shown in the following table:

	2007	2008	2009	2010	2011	2012
Fund PER	8.4	7.4	14.4	9.5	8.9	10.0
S&P 500 PER	17.3	28.8	25.1	17.0	14.8	14.3
Premium (+) / Discount (-)	*-51%*	*-74%*	*-43%*	*-44%*	*-40%*	*-30%*
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 Inc.

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. At the end of December the median P/E ratio of this group was 8.3x 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 P/E of 10.0x 2012 earnings, given the company's good growth prospects.

Our exploration and production exposure (c.40%) gives 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 P/E terms, the group divides roughly into two: (i) ConocoPhillips, Apache, Chesapeake, Devon, Newfield, Ultra and Stone all with quite low P/Es (5.3x – 8.6x 2011 earnings) and (ii) Noble, Carrizo, Penn Virginia, QEP and Bill Barrett with higher P/E ratios (10.1x – 20.4x 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 2.9x 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 6.9x 2012 earnings. JKX is a gas focused E&P company with production in the Ukraine and trades on 3.5x 2011 earnings. Afren focuses on offshore West African production and trades on 7.7x 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 4.7x 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 10.4x and 11.0x 2012 earnings) and those which operate in the US and internationally (Helix, Transocean and Halliburton on 11.1x – 12.9x 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 2011 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 PERs of 1.3x and 0.6x respectively.

Portfolio at December 31, 2012

Guinness Atkinson Global Energy Fund 31 December 2012

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	3.34	13.2	11.9	10.2	22.3	14.5	10.3	10.9	10.9
Chevron Corp	US1667641005	USD	US	3.34	13.9	12.3	9.5	21.1	11.6	8.0	8.8	8.9
Royal Dutch Shell PLC	GB00B03MLX29	EUR	NL	3.36	8.5	6.8	7.8	15.1	11.0	8.2	7.8	7.5
BP PLC	GB0007980591	GBP	GB	3.38	6.2	6.3	5.0	8.8	6.1	6.0	7.3	7.3
Total SA	FR0000120271	EUR	FR	3.40	7.1	7.3	6.3	11.3	8.4	7.6	7.3	7.4
ENI SpA	IT0003132476	EUR	IT	3.42	6.6	7.2	6.7	13.1	9.9	9.5	9.1	8.8
Statoil ASA	NO0010096985	NOK	NO	3.41	7.4	10.0	7.5	13.8	10.4	8.9	8.3	8.3
Hess Corp	US42809H1077	USD	US	3.39	9.6	8.9	7.2	27.7	10.3	8.8	8.7	8.1
OMV AG	AT0000743059	EUR	AT	3.34	5.4	5.2	4.3	11.0	6.9	8.6	6.2	6.4
				30.38								
Integrated Oil & Gas - Canada												
Suncor Energy Inc	CA8672241079	CAD	CA	3.40	13.3	13.7	10.3	30.9	20.6	9.2	10.0	9.9
Integrated Oil & Gas - Emerging market												
PetroChina Co Ltd	CNE1000003W8	HKD	HK	3.54	11.3	11.0	14.2	15.1	12.1	11.9	12.9	11.3
Gazprom OAO	US3682872078	USD	RU	1.82	5.4	5.3	4.6	5.1	3.8	2.8	3.0	3.2
				5.36								
Oil & Gas E&P												
ConocoPhillips	US20825C1045	USD	US	3.34	5.85	5.99	5.44	16.03	9.78	6.82	10.09	9.82
Apache Corp	US0374111054	USD	US	3.35	10.7	9.1	7.0	14.1	8.5	6.6	8.2	8.1
Bill Barrett Corp	US06846N1046	USD	US	1.09	12.6	18.3	6.5	10.5	8.8	10.1	72.6	19.0
QEP Resources Inc	US74733V1008	USD	US	1.27	nm	nm	nm	nm	21.9	18.5	24.1	19.0
Ultra Petroleum Corp	CA9039141093	USD	US	1.13	12.7	15.9	6.8	10.0	8.1	7.1	10.0	17.8
Devon Energy Corp	US25179M1036	USD	US	3.30	8.3	7.5	5.3	14.4	8.8	8.6	16.1	12.4
Chesapeake Energy Corp	US1651671075	USD	US	3.28	4.6	5.2	4.7	6.7	5.7	5.9	33.0	12.6
Noble Energy Inc	US6550441058	USD	US	3.43	26.8	18.7	14.4	30.1	24.6	19.4	22.2	15.7
Newfield Exploration Co	US6512901082	USD	US	3.38	7.6	8.3	8.5	5.3	5.8	6.6	11.0	11.2
Stone Energy Corp	US8616421066	USD	US	1.84	7.5	4.0	3.7	8.9	10.1	5.3	7.2	8.8
Carrizo Oil & Gas Inc	US1445771033	USD	US	1.70	29.5	29.9	11.6	14.2	16.4	20.4	14.1	8.0
Penn Virginia Corp	US7078821060	USD	US	1.14	2.4	2.4	1.7	nm	nm	nm	nm	nm
Bayfield Energy Holdings PLC	GB00B3N3KL75	GBP	GB	0.25	nm	nm	nm	nm	nm	nm	37.4	2.3
Ophir Energy PLC	GB00B24CT194	GBP	GB	0.66	nm	nm	nm	nm	nm	nm	nm	nm
Triangle Petroleum Corp	US89600B2016	USD	US	0.53	nm	nm	nm	nm	nm	nm	nm	nm
Pantheon Resources PLC	GB00B125SX82	GBP	GB	0.05	nm	nm	nm	nm	nm	nm	nm	nm
Cluff Natural Resources PLC	GB00B6SYKF01	GBP	GB	0.13	nm	nm	nm	nm	nm	nm	nm	nm
				29.88								
Oil & Gas E&P - Canada												
Canadian Natural Resources Ltd	CA1363851017	CAD	CA	3.42	19.6	13.6	8.8	11.9	11.8	12.4	17.8	12.2
				3.42								
Oil & Gas E&P - Emerging markets												
Dragon Oil PLC	IE0000590798	GBP	GB	1.97	25.3	15.0	12.5	18.1	13.1	7.1	6.9	6.4
Petrominerales Ltd	CA71673R1073	CAD	CA	1.25	51.1	17.7	6.8	8.9	3.5	2.4	4.6	8.1
Afren PLC	GB00B0672758	GBP	GB	1.91	nm	nm	nm	180.4	33.8	17.0	7.9	8.2
Soco International PLC	GB00B572ZV91	GBP	GB	1.87	54.7	50.3	54.1	33.7	46.4	30.0	8.0	7.1
JKX Oil & Gas PLC	GB0004697420	GBP	GB	0.80	2.5	2.0	2.5	2.7	3.0	3.5	3.5	4.8
WesternZagros Resources Ltd	CA9600081009	CAD	CA	0.44	nm	nm	nm	nm	nm	nm	nm	45.8
				8.23								
Drilling												
Transocean Ltd/Switzerland	CH0048265513	USD	US	0.74	15.2	4.1	3.1	3.8	7.5	31.5	12.9	9.3
Patterson-UTI Energy Inc	US7034811015	USD	US	3.35	4.6	7.3	7.9	nm	27.5	8.6	10.4	16.9
Unit Corp	US9092181091	USD	US	3.32	6.7	7.9	6.6	17.1	14.8	11.0	11.0	11.1
				7.41								
Equipment & Services												
Halliburton Co	US4062161017	USD	US	3.42	15.8	13.7	16.0	26.5	17.3	10.4	11.7	11.5
Helix Energy Solutions Group Inc	US42330P1075	USD	US	3.55	7.2	6.2	8.5	35.6	39.1	13.7	11.1	13.7
Shandong Molong Petroleum Machinery Co Ltd	CNE1000001N1	HKD	HK	0.09	12.7	8.8	5.9	16.2	6.3	8.8	nm	nm
				7.06								
Solar												
Trina Solar Ltd	US89628E1047	USD	US	0.72	nm	6.0	3.6	2.7	1.3	144.7	nm	nm
JA Solar Holdings Co Ltd	US4660902069	USD	US	0.53	4.9	13.3	19.7	nm	0.6	nm	nm	nm
				1.24								
Oil & Gas Refining & Marketing												
Valero Energy Corp	US91913Y1001	USD	US	3.42	4.1	4.4	6.3	nm	21.5	8.6	7.2	7.0
				3.42								
Construction & Engineering												
Kentz Corp Ltd	JE00B28ZGP75	GBP	GB	0.59	nm	24.7	25.0	24.6	16.9	12.8	10.8	9.3
			Cash	-0.37								
			Total	100								
				PER	8.7	8.4	7.4	14.4	9.5	8.9	10.0	9.7
				Med. PER	8.5	8.3	6.8	14.2	10.2	8.8	10.0	8.9

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.

5. Outlook

Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply over the last 11 years, together with the IEA forecasts for 2012 and 2013.

	2001	2002	2003	2004	2005	2006	2007	2008	*2009*	2010	2011	*2012e*	2013e
												IEA	*IEA*
World Demand	77.4	77.7	79.3	82.5	84.0	85.2	87.0	86.5	85.4	88.0	88.9	*89.7*	*90.5*
Non-OPEC supply (includes Angola and Ecuador for periods when each country was outside OPEC[1])	47.2	48.1	49.1	50.3	50.4	51.3	50.5	49.6	51.4	52.6	52.8	*53.3*	*54.2*
Angola supply adjustment[1]	-0.7	-0.9	-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	-0.4	-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]	1.2	1.1	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)	47.3	47.9	48.8	49.8	49.6	50.3	51.0	50.6	51.4	52.6	52.8	53.3	54.2
OPEC NGLs	3.4	3.7	3.9	4.2	4.3	4.3	4.3	4.5	4.9	5.4	5.8	*6.2*	*6.5*
Non-OPEC supply plus OPEC NGLs (ex. Angola/Ecuador and inc. Indonesia for all periods)	50.7	51.6	52.7	54.0	53.9	54.6	55.3	55.1	56.3	58.0	58.6	59.5	60.7
Call on OPEC-12[3]	26.7	26.1	26.6	28.5	30.1	30.6	31.7	31.4	29.1	30.0	30.3	30.2	29.8
Iraq supply adjustment[4]	-2.4	-2.0	-1.3	-2.0	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.6	-3.0	-3.0
Call on OPEC-11[5]	24.3	24.1	25.3	26.5	28.3	28.7	29.6	29.0	26.7	27.6	27.7	27.2	26.8

[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: 2000 - 2008: IEA oil market reports; 2009 - 12: 12 December 2012 Oil market Report

Global oil demand in 2011 was 1.9m 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 shrugged off remarkably quickly. The IEA forecast a further 0.8m b/day rise in demand in both 2012 and 2013. The 2012 forecast is nearly behind us now, but the key variable driving the 2013 forecast – global GDP growth – is subject to uncertainty at present.

OPEC

Three 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 barrel 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. Because of these issues, OPEC members have been producing well in excess of the new target, with the December 2012 production number for OPEC-11 at 28.1m b/day. None of this detracts from 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.

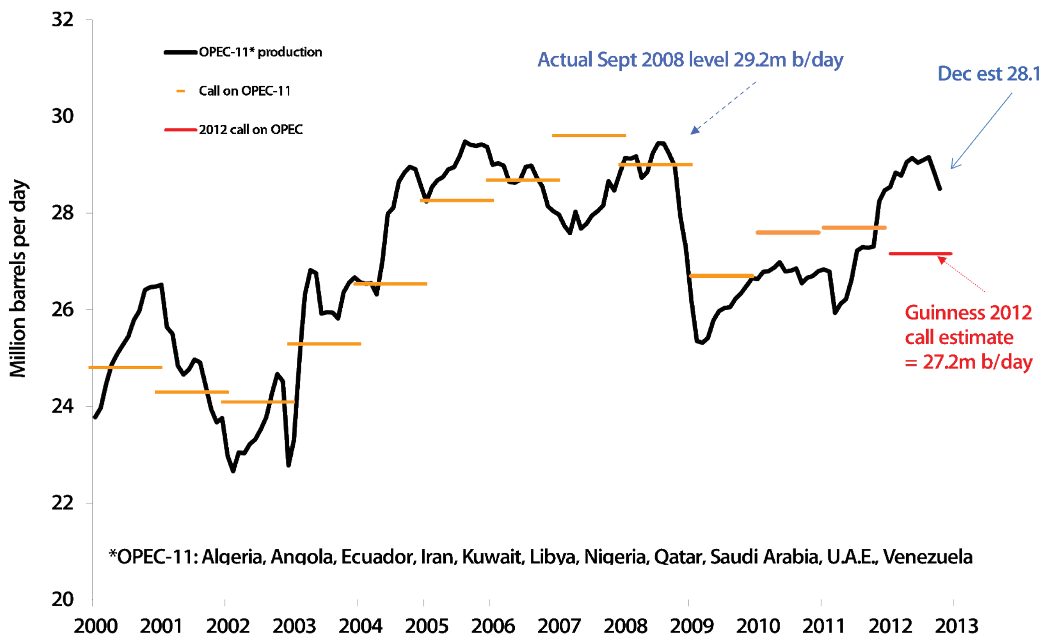
The table below shows changes in production among OPEC-12 since the start of 2011 and shows how that production is running significantly ahead of pre-MENA unrest levels. In addition to the non-OPEC problems mentioned above, Saudi Arabia's increased production is an indication of their desire to see US 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 1.3m b/day, and total OPEC-12 production is 2.2m b/day higher than December 2010. En passant, a puzzle exists here: the call on OPEC-12 is thought to be up only slightly over the past two years (the rise in global demand being met by an increase in non-OPEC supply, OPEC NGLs and rising Iraqi production). Given that OECD oil inventories have not been meaningfully loosening in recent months, where is this production going? It suggests either that world demand is stronger than pundits believe or Iranian exports and/or production are down more than thought. The latest Iranian supply number is notably weak at 2.7m b/day (1m b/day lower than December 2010), so the answer probably lies in both camps.

('000 b/day)	31-Dec-10	31-Dec-12	Change
Saudi	8,250	9,570	1,320
Iran	3,700	2,660	-1,040
UAE	2,310	2,650	340
Kuwait	2,300	2,800	500
Nigeria	2,220	1,890	-330
Venezuela	2,190	2,870	680
Angola	1,700	1,720	20
Libya	1,585	1,540	-45
Algeria	1,260	1,180	-80
Qatar	820	750	-70
Ecuador	465	504	39
OPEC-11	26,800	28,134	1,334
Iraq	2,385	3,300	915
OPEC-12	29,185	31,434	2,249

Source: Bloomberg LP (January 2013)

The graph below shows the estimated call on OPEC-11 for 2012, which we currently estimate to be around 27.2m b/day versus apparent production of 28.1m b/day. Given that the market is in reasonable balance, it suggests that the actual call has recently been higher than 27.2m b/day.

Figure 6: OPEC apparent production vs. call on OPEC 2000 – 2012



Source: Bloomberg/IEA Oil Market Report (December 2012)

Supply looking forward

The non-OPEC world is struggling to grow production meaningfully. The growth was 2% p.a. between 1998-2003, 1% p.a. from 2003-2008 and is forecast to be 1.3% p.a. from 2008-2012.

Non-OPEC production growth for 2011 was 0.2m b/day (up by just c. 0.4%), having been forecast as high as 0.8m b/day at the start of the year. Since then, supply growth in every region except North America was revised down. The IEA currently forecast non-OPEC supply growth of 0.5m b/day in 2012. Interestingly, all of the growth comes from North America (+1.1m b/day vs -0.6m b/day for the rest of non-OPEC), reflecting growth in oil sands (Canada) and oil shales (Bakken; Eagleford; Permian). The decline in the rest of non-OPEC in 2012 is largely driven by political factors, as problems have persisted in Syria, Yemen and Sudan (though Sudan is starting to pick up).

The IEA forecast non-OPEC supply growing by 0.9m b/day in 2013, driven again by North American supply (+0.8m 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 questions 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 10-15m b/day over the next 10 years. Iraqi production was running at 3.3m b/day in December, down from a high of 3.6m b/day in mid-2000. Despite this potential, continued unrest across the country does not fill one with confidence that they can easily be achieved.

A new and interesting source of growing non-OPEC supply is the oil being produced in North America from horizontal drilling and hydraulic fracturing to produce oil sourced from or in oil shales. The Bakken in Dakota, and the Permian and Eagleford in Texas are good examples. So far, new oil production from these sources amounts to around 1.0m b/day, all of which has come into supply over the past 4 years. Our assessment is that this is a high cost source of oil but one that is viable at current oil prices. It could be comparable in size to the UK North Sea ie it could grow to by a further 3m b/day between now and 2020, 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 3 years (i.e. growth of 0.2m b/day per year to 2015). Similar opportunities may exist in Argentina, China and Poland but their development is likely to be deferred until the following decade. As high cost oil (where much of the oil that can be recovered arrives in the 36 months after a well is drilled), horizontally drilled "shale" oil has the interesting potential to stabilize the oil price in the $80 – 100 band that we foresee ahead, as drilling activity will likely expand and shrink as the oil price fluctuates.

We are also reminded of future sources of new oil supply. 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. Mindful of the effect of supply expansion, we must also consider changing levels of demand.

Demand looking forward

The IEA forecast for growth in oil demand in 2012 is 0.8m b/day, comprising an increase in non-OECD demand of 1.3m b/day and a decline in OECD demand of 0.5m b/day. The non-OECD growth forecast is very similar to 2011 and 0.8m lower than the 2m b/day growth in 2010. The components of this growth can be summarized as follows:

Figure 7: Non-OECD oil demand

Million b/day	Demand				Growth		
	2009	2010	2011	2012	2010	2011	2012
Asia	18.25	19.65	20.28	20.91	1.40	0.63	0.63
M. East	7.10	7.32	7.37	7.58	0.22	0.05	0.21
Lat. Am.	5.70	6.04	6.29	6.46	0.34	0.25	0.17
FSU	4.00	4.15	4.43	4.55	0.15	0.28	0.12
Africa	3.37	3.30	3.29	3.40	-0.07	-0.01	0.11
Europe	0.70	0.68	0.69	0.72	-0.02	0.01	0.03
	39.12	41.14	42.35	43.62	2.02	1.21	1.27

Source: IEA Oil Market Report (December 2012)

As can be seen, the main area of decline in growth since 2010 is in Asia, and though down, the collective growth in the Middle East, Latin America, Former Soviet Union (FSU) and Africa is likely in 2012 to just outstrip that in Asia. A word on China demand growth: of the 1.3m b/day of non-OECD growth forecast for 2012, China represents 0.3m b/day (24%). As recently as 2010, growth from China (0.9m b/day) represented 45% of total non-OECD demand growth (2.0m b/day). The Middle East, Africa, other areas of Asia, and Latin America are all central to the developing world industrialization and urbanization thesis and should not be overlooked.

For OECD demand in 2012, the IEA's forecast of a decline of 0.5m b/day sees North America and Europe down and the Pacific up. The expected decline in European demand broadly 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 1-1.5m b/day to the end of the decade.

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 summarizes our view by showing our oil price forecasts for WTI and Brent against their historic levels, and rises in percentage terms that we have seen in the period from 2002 to 2011.

Figure 8: Average WTI & Brent yearly prices, and changes

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Average WTI ($)	26.1	31.2	41.7	56.6	66.1	72.2	99.9	61.9	79	95	94
Average Brent ($)	25.1	28.9	38.5	54.7	65.5	73.2	97.1	62.5	80.8	111	112
Average Brent and WTI	25.6	30.1	40.1	55.7	65.8	72.7	98.5	62.2	79.9	103.0	103
Average Brent and WTI Change$^+$ y-o-y ($)	-	4.45	10.1	15.6	10.2	6.9	25.8	-36.3	17.7	23.1	0
Avge Change$^+$ y-o-y (%)	-	17%	33%	39%	18%	10%	35%	-37%	28%	29%	0%

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 $90 (average) will be prevented by significant OPEC cuts.

In the short term, the restoration of Libyan 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 destabilize 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 ($90-110).

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 an estimated 18.8 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. This in turn precipitated a gas price sell off. The last nine months have seen (a) the gas rig count fall week on week as producers seek to cut back supply and (b) coal to gas switching by US electricity utilities burgeon.

Total gas demand in 2012 (excluding Canadian exports) is estimated to have been 71.6 Bcf/day, up by 3.4 Bcf/day (5.0%) vs 2011 and up 6.2 Bcf/day (10%) vs the 5 year average. The principal contributor to the increase in 2012 vs. 2011 was power generation (+4.5 Bcf/day), driven by coal to gas switching. Other notable changes were industrial demand (+0.4 Bcf/day), exports to Mexico (+0.5 Bcf/day) and residential/commercial demand (-2.2 Bcf/day) which was pulled lower by the very warm start to the year.

Overall, while gas demand in the US has been reasonably strong over the past 3 years, it has been trumped over this period by a rise in onshore supply, as discussed above.

Supply Outlook

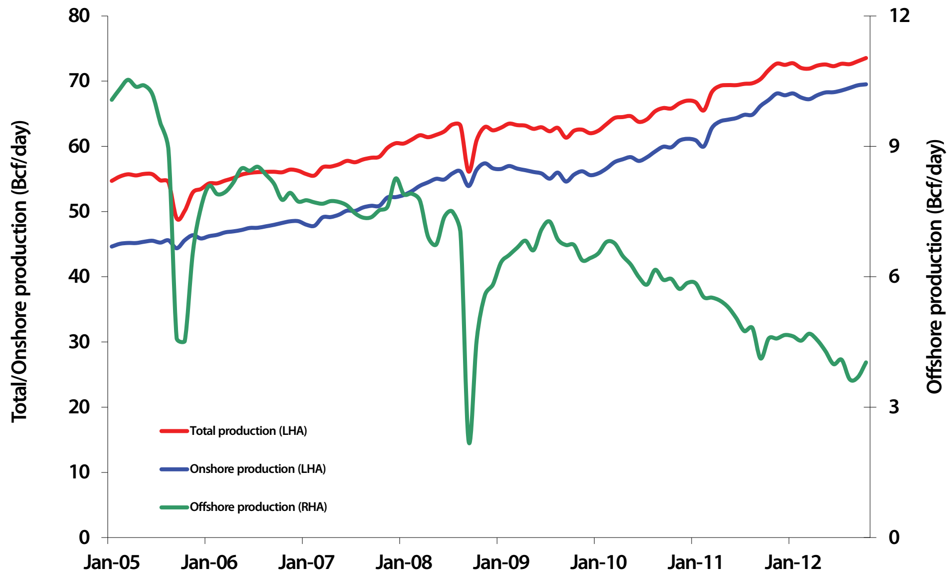
Change in Rig Count

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 431 at end-December 2012. Over the same period the oil rig count has risen from 416 to 1,327. The total number of rigs has therefore declined recently but not changed hugely (it has gone from 2,024 Sept 2008 to 1,983 Sept 2011 to 1,758 December 2012. Within this, however, the mix has changed as illustrated by the following table:

RIG COUNT BHI	Aug		Sept		Dec	
	2008		**2011**		**2012**	
Gas Rigs	1606		923		431	
Oil Rigs	416		1060		1327	
Total Rigs	2022		1983		1758	
		%				*%*
Horizontal Rigs	636	*31%*	1135	*57%*	1111	*63%*
Directional Rigs	388	*19%*	238	*12%*	175	*10%*
Vertical Rigs	1017	*50%*	617	*31%*	477	*27%*
Total Rigs	2041	*100%*	1990	*100%*	1763	*100%*

One result of the change from vertical to horizontal drilling has been that onshore gas supply has continued to rise and is now at c 69.5 Bcf/day, around 12.1 Bcf/day (21%) 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 9: US natural gas production 2005 – 2012 (Lower 48 States)



Source: EIA 914 data (October 2012 published in January 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 – declined slightly in December but is at a very significant premium to the US gas price ($10.60 versus $3.44). LNG supplies to the UK have been somewhat constrained, particularly in light of strong demand for LNG to Asian markets and this has been helping to support the price in recent months. US LNG imports remained around 0.5 Bcf/day in December 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 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 now on gas demand in 2013. Here we see demand from power generation down on 2012 (some of the coal to gas switching is likely to reverse if the gas price stays above $3) but about 1-2 Bcf/day above 2011. Residential and commercial gas demand will, as ever, be weather dependent, but assuming average temperatures, it 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 73-74 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 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 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 should 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.

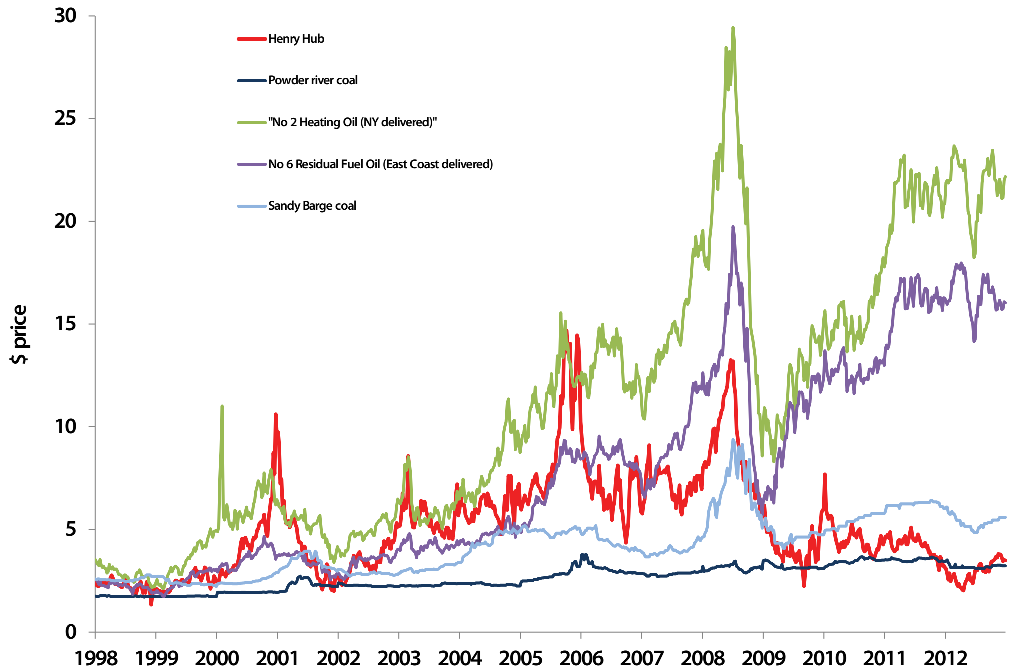
We also watch with interest the efforts being made to increase the usage of LPG and LNG by the US truck, bus and delivery van fleets. Whether this will gain traction is hard to know. If it does its impact will be meaningful. If the entire fleet described above moved to gas, we estimate that it would increase demand by 18 Bcf/day.

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 26.7x at the end of December 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 the year, resulting coal to gas switching for power generation was been significant. It will be interesting to see how much of the switching persists in 2013 with gas back above $3/Mcf – some but not all, we think.

Figure 10: 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 (December 31 2012)

Conclusions about US natural gas

The US natural gas price has bottomed and the recovery has begun. Natural gas at around $3.50 spot is still below the (full cycle) marginal cost of supply and as further reduced 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. A key factor still depressing the price today is the quantum of the gas storage surplus. The current surplus of 361 Bcf needs around 4 Bcf/day of undersupply versus demand to bring it back to normal by end March 2013 given average weather.

6. Appendix: Oil and Gas markets historical context

Figure 11: Oil price (WTI $) last 22 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 4 m 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.

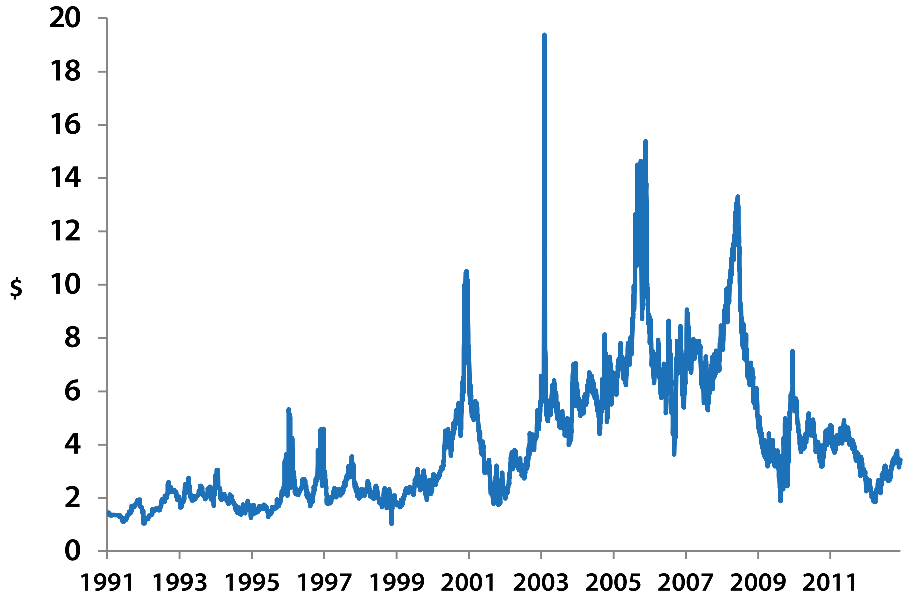
Then, in late 2002 early 2003, war in Iraq and a general strike in Venezuela caused the price to spike upward. This was quickly followed by a sharp sell-off due to the swift capture of Iraq's Southern oil fields by Allied Forces and expectation that they would win easily. Then higher prices were generated 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 stabilize in the $70-95 range where it remained for over 18 months. In 2011 and early 2012 the price has spiked again above $100 in response to unrest in North Africa and the Middle East and declining OPEC spare capacity, but the spikes have been relatively short-lived.

Figure 12: North American gas price last 20 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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