GUINNESS ATKINSON FUNDS

Energy brief

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August 2013

Commentary and Review by portfolio managers
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REPORT HIGHLIGHTS

FUND NEWS

• *Fund size $73 million at end of July*

OIL

• ***WTI & Brent rise; Spread narrows to $4***

WTI rose from $97 to $105 in July. Brent increased by $7, ending at $109. Price supported by strong US demand and African supply disruption, particularly in Libya.

NATURAL GAS

• ***US gas price falls to $3.46***

Henry Hub spot traded down 11 cents to end July at $3.46 on summer weather outlook (still well up from April 2012 low of $1.84). 12-month gas strip price fell 1% to $3.72. Market slightly oversupplied (by circa (c.) 1bcf/day

EQUITIES

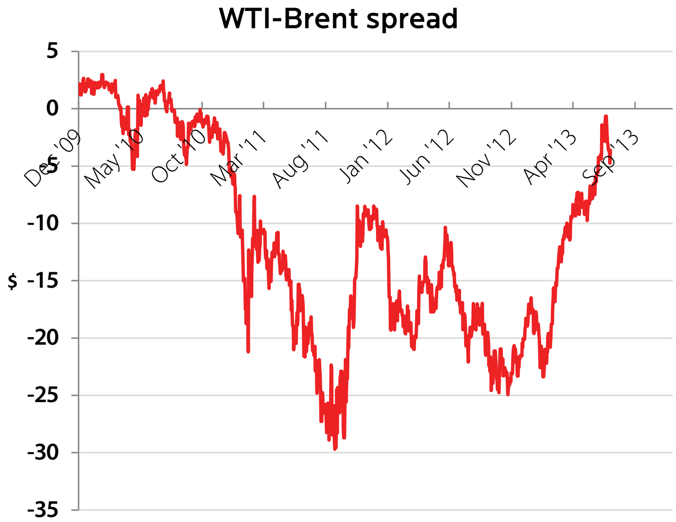
• ***Energy equities strong***

The MSCI World Energy Index rose by 5.46% in July, as the MSCI World Index rose by 5.31% over the period (all in US dollar terms). Fund outperforms both.

Chart of the Month:

WTI-Brent spread narrows further

The spread between the WTI and Brent oil prices narrowed further this month, from $5.60 at the end of June, to $3.63 at the end of July. At one point in July, the spread reached as low as $0.66 – a level not seen since October 2010. The spread, which began to open up at the end of 2010, reached a maximum of $29.70 in September 2011, largely due to increased US onshore oil production that has resulted in infrastructure bottlenecks and elevated oil inventory levels in Cushing, Oklahoma. The recent narrowing of the spread can be attributed to pipeline extensions, which have improved the ability of producers to transport oil out of the US midcontinent, and small increases in domestic refining capacity have helped to reduce storage levels at Cushing.

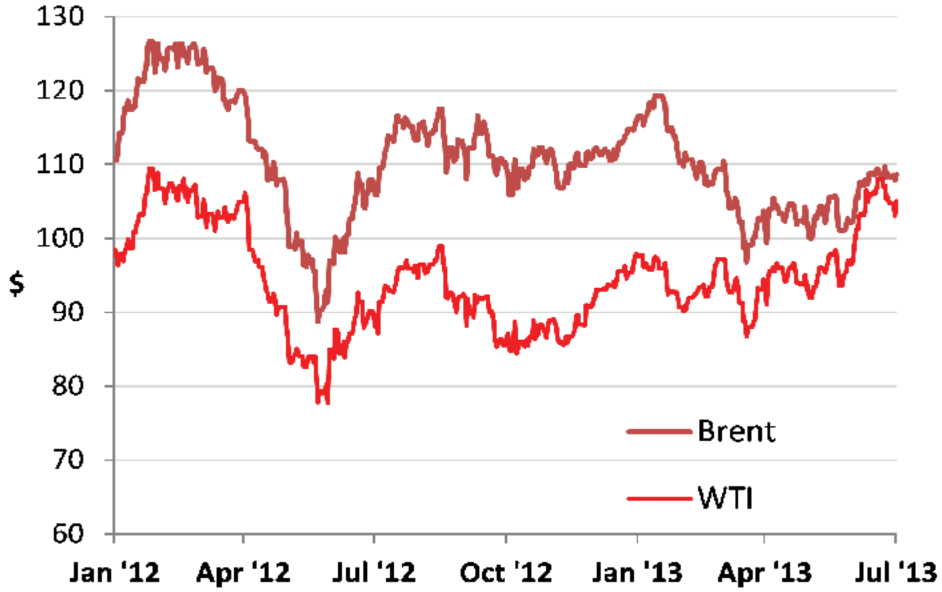


Source: Bloomberg, Guinness Atkinson Asset Management (August 2013)

1. July 2013 Review

Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months January 31, 2012 to July 31, 2013



Source: Bloomberg

The West Texas Intermediate (WTI) oil price opened July at $96.56. The price rose over the month to reach a high on July 18 of $108.05, before declining to close the month at $105.03. So far this year, WTI has averaged $95.77. WTI averaged $94.12 in 2012 and $95.04 in 2011.

Brent also rose in July, increasing from $102.16 to $108.66. The gap between the WTI and Brent benchmark oil prices, which started at the beginning of 2011, narrowed to around $4. The spread, caused by high stock levels and infrastructure bottlenecks resulting from increased US onshore production, has narrowed considerably over the past 5 months following pipeline capacity expansions in numerous oil producing basins.

Factors which strengthened the WTI oil price in July:

- **Sharp decline in US oil inventories**

US stocks of unrefined crude oil fell sharply in July. Total crude stocks were down 19 million barrels versus the 5 year average decline of 7 million barrels. The decline is likely due to a combination of factors, including stronger than expected domestic demand (up 4% year on year), disruption to Canadian supplies and lower imports resulting from a tighter global oil balance. Total US inventories, including refined products, also declined in July, the first time this has happened since 2002. Despite the drop, overall US refined product inventories remain relatively higher than in Europe and Asia.

- **African supply disruption**

A number of issues across Africa combined to dampen oil supply from the region. In particular, the latest bout of unrest in Libya continues to have a significant impact, with July production (0.8 million (m) barrels(b)/day) down 0.55m b/day compared to May. Renewed unrest in Egypt following the ousting of President Morsi, has raised concern over disruption there (though note that during the 2011/2012 unrest, no disruption materialized). Egypt produces around 0.73m b/day of liquids (0.8% of world supply) and also controls the 2.4m b/day SUMED pipeline, which flows oil from the Red Sea to the Mediterranean. Further south, Nigerian production was affected in July by damage to pipelines and other infrastructure. Oil output from Nigeria in July was reported at 1.92m b/day, down 0.1m b/day versus June.

- **Rising non-commercial futures position**

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position rose again in July from 275,000 to 361,000 contracts long. This represents an all-time high and will have supported the rise of WTI during the month.

- **Strong 2014 demand expectations**

The International Energy Agency (IEA) published their 2014 global oil demand forecast in July. Their expectation is for growth of 1.2m b/day, higher growth than 2012 (0.9m b/day) and the forecast for 2013 (1.0m b/day). Non-OECD demand growth marches on, up an expected 1.4m b/day (note that we talk about 1.5m b/day growth every year for the next decade), but as notable is the shallowness of the expected decline in OECD demand, which is down only 0.2m b/day. If this proves accurate, it will be the slowest rate of OECD demand contraction since the 2008 financial crisis.

Factors which weakened the WTI oil price in July:

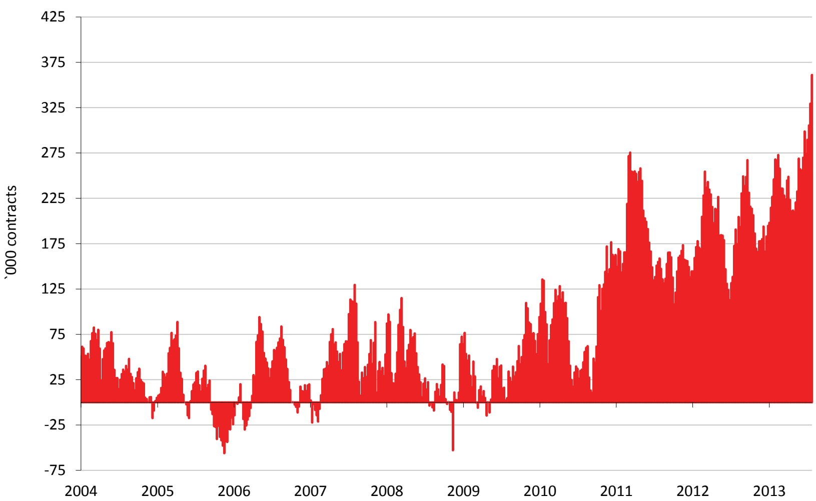
- **Build in OECD inventories**

OECD inventories (total crude and product stocks) for June 2013 (the latest data point available) grew by 23 million barrels to an estimated 2,706 million barrels. The build of 23 million barrels compares to an average June build over the preceding 10 years of 7 million barrels. Overall inventory levels are in the top half of the high-low range over the last 10 years but not unusually high.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position rose in again in July. It started the month at 275,000 contracts long and increased each week to an all-time high at the end of the month of 361,000 contracts. We regard a net long position over 200,000 contracts to be relatively high – any unwinding will likely dampen the WTI price.

Figure 2: NYMEX Non-commercial net futures contracts: WTI January 2004 – July 2013



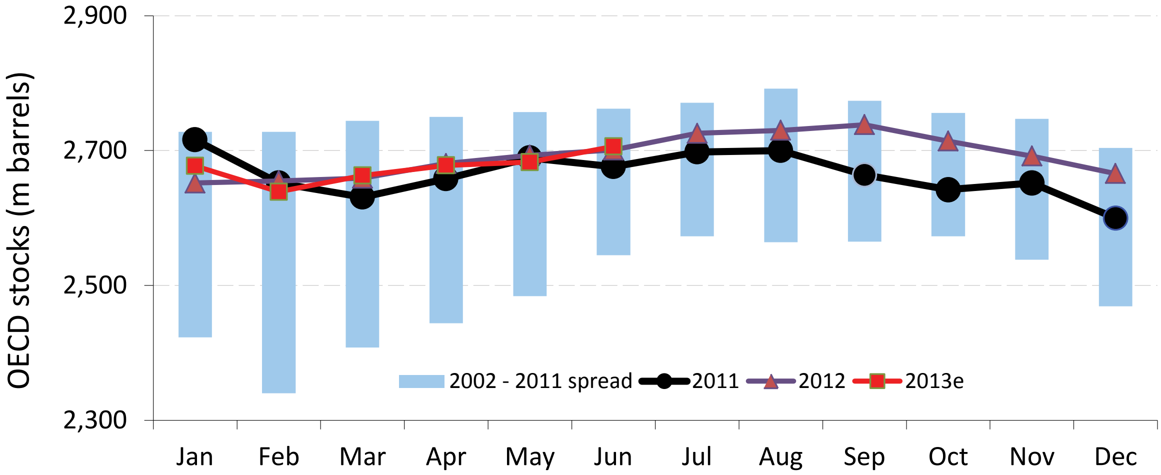
Source: Bloomberg LP/Nymex (July 2013)

OECD stocks

OECD estimated total crude and product stocks for June 2013 (published in the July 2013 IEA Oil Market Report) grew by 23 million barrels from 2,683 million barrels, giving a total stock of 2,706 million barrels. Over the preceding ten years, the average inventory build in June was 7 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 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. So far in 2013, inventories have remained reasonably well behaved, falling in the top half of the 2002-2011 range.

Figure 3: OECD total product and crude inventories, monthly, 1998 to 2013



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

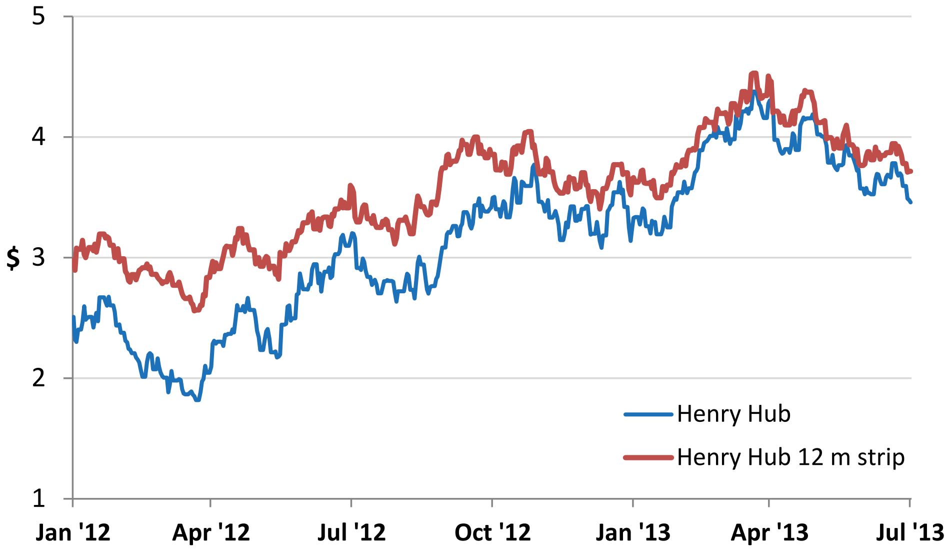
2. Natural Gas Market

The US spot natural gas price (Henry Hub) opened July at $3.57 per Mcf (1000 cubic feet), rose to reach a high for the month of $3.78, before falling to close July at $3.46.

Despite the decline in July, the spot gas price has nearly doubled from a low of $1.84 in April 2012. The price has averaged $3.74 so far in 2013, well above the 2012 average of $2.75 but 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) fell over the month by 1% from $3.76 to $3.72. The strip price has averaged $3.95 so far this year, having averaged $3.28 last year, $4.35 in 2011, $4.86 in 2010 and $5.25 in 2009.

Figure 4: Henry Hub Gas spot price and 12m strip ($/Mcf) January 31, 2011 to July 31, 2013

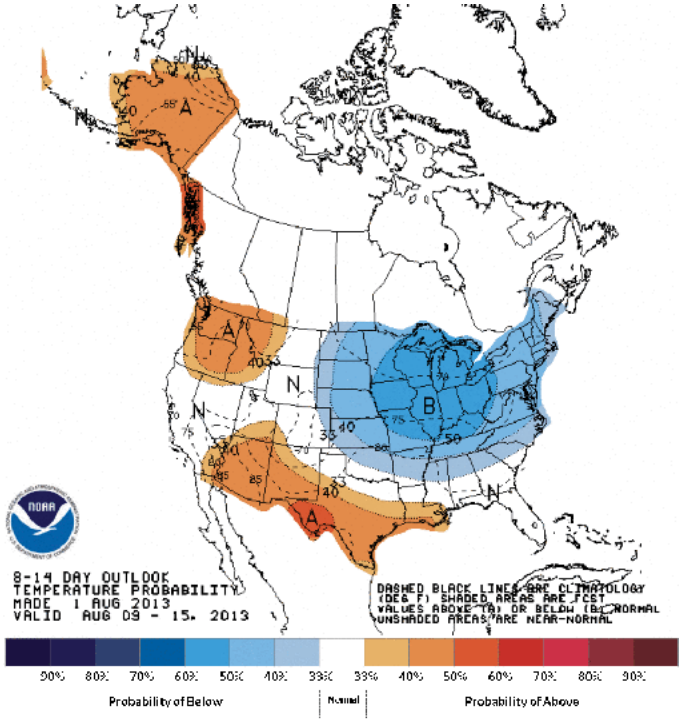


Source: Bloomberg

Factors which weakened the US gas price in July included:

- **Cool summer weather outlook**

Expectations of a cold weather in the US in August, and thus lower-than-normal energy demand for air conditioning, led to a sell-off in the Henry Hub spot price towards the end of July. The spread between the spot price and the strip price, a reflection of short-term market expectations, widened during the month from 19 cents(c) at the end of June to 26c at the end of July, indicating poor near-term expectations for the natural gas market. The following image shows the 8-14 day weather outlook – the blue area in the populous East indicates colder than average expected temperature, outweighing warmer weather in the West.



Source: National Oceanic and Atmospheric Administration (August 2013)

- **Overall market slightly oversupplied**

Our analysis of injections of gas into storage implies that the market has shifted over the past 3 months from slight undersupply (April) to slight oversupply (May to July). We estimate the oversupply to be around 1 billion cubic feet (bcf)/day.

- **Gas to coal switching**

With the gas spot price in July trading at around $3.50, it is likely that much 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. This implied that in total, coal and natural gas were fueling the same amount of electricity generation. We believe the level of switching is now down to less than 2 Bcf/day (implying that coal has regained its lead in overall electricity generation), but even this smaller amount could affect the overall balance of the gas market should it fluctuate from here.

Factors which strengthened the US gas price in July included:

- **US onshore production flat**

The May data (latest available) from the Energy Information Agency indicated that total US natural gas production (Lower 48 States) was broadly unchanged month-on-month. Total onshore production rose by 0.2 Bcf/day month-on-month, implying that offshore production fell slightly. We are encouraged that total production for May 2013 remains 0.4Bcf/day below peak production in November 2012.

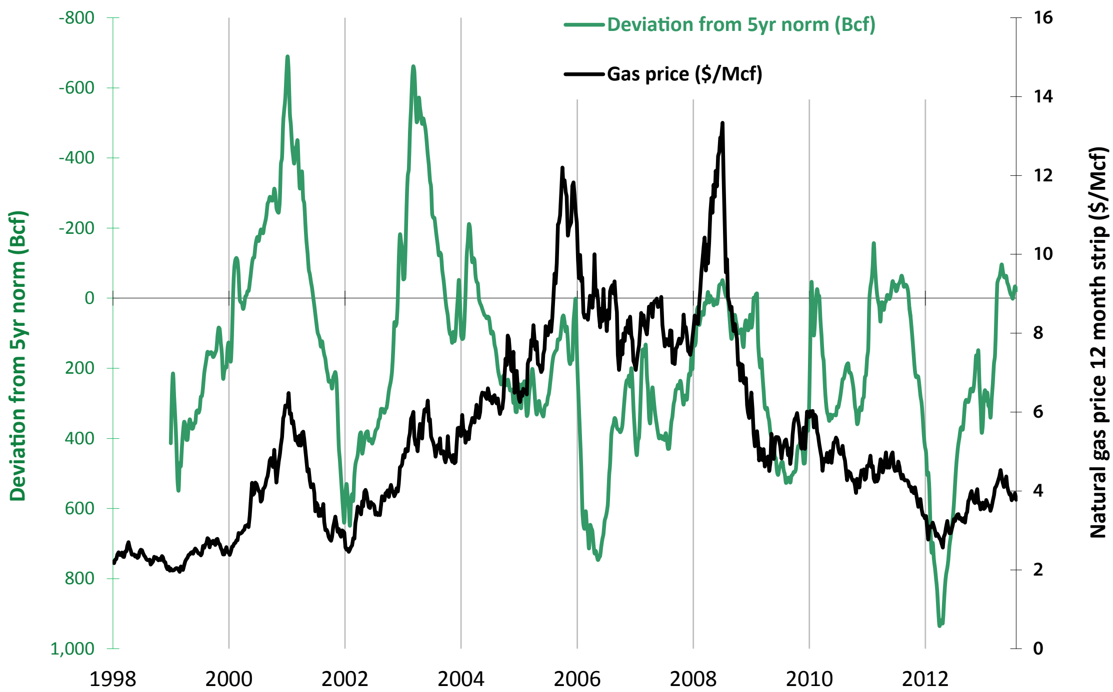
- **Low gas drilling rig count**

The US natural gas-directed rig count (reported by Baker Hughes) rose from 353 to 369 rigs during July. However, over the last 18 months the rig count has declined from 923 rigs (i.e. by 60%). 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.

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 (July 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 $3.50 now.

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

3. Manager's Comments

Last month, the IEA unveiled their outlook for oil in 2014. Oil demand growth is expected to accelerate to 1.2m b/day (versus 1m b/day in 2013), with non-OPEC supply growth also growing by similar amount. The forecasts don't look unreasonable, though with geopolitical risk in the Middle East and Africa and operational risk in mature basins elsewhere, we view non-OPEC supply disappointment (as we have seen for the last 3 years) as more likely than demand disappointment.

What does this mean for price? 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.

The market looks balanced, though we should recognize that we are only one ill-judged military move in the Middle East and North Africa (MENA) region away from another oil spike.

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). So far, they are succeeding.

The US gas price has now recovered from its 2012 lows. While the spot price has been dampened most recently by an outlook for cool summer weather, the market looks in much better fundamental balance than a year ago. Production growth has flattened, demand is good and gas in storage is normal.

A wall of new US gas demand is coming, starting in 2015: exports of gas via LNG; expanded export capacity into Mexico; coal plant retirements; gas' share of electricity generation growing; industrial in-shoring; natural gas vehicles.

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 of 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.

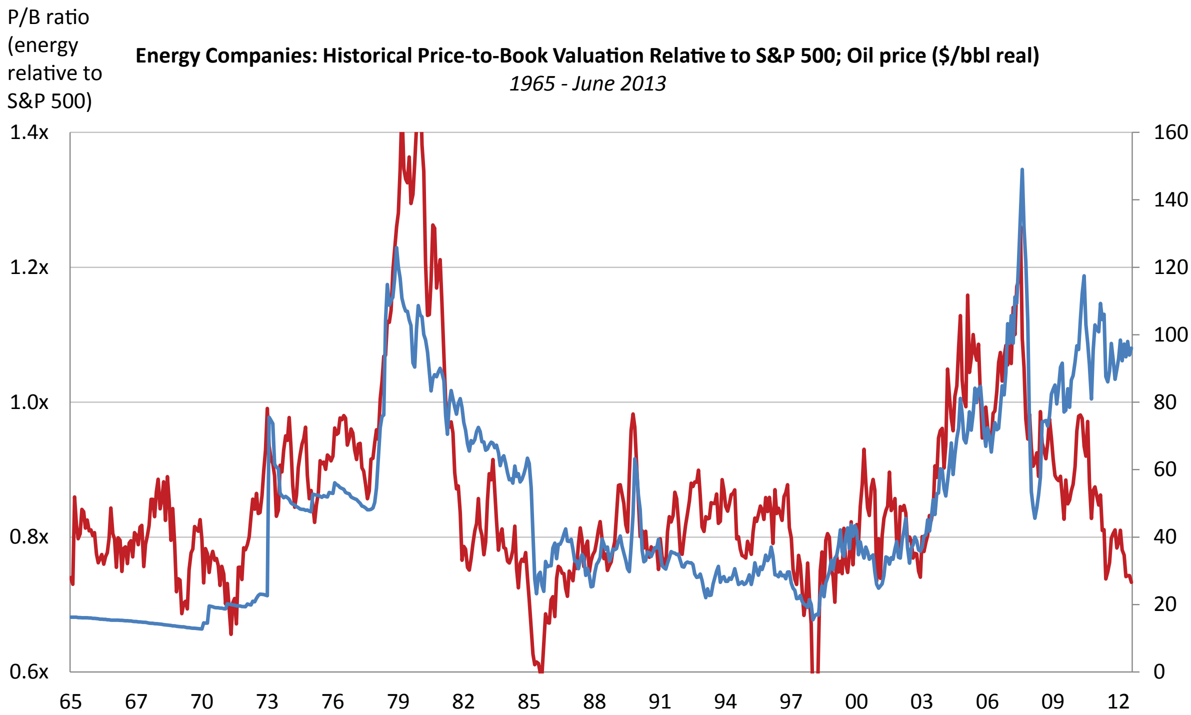
Outlook for energy equities

Energy equities over the past 12 months have been ahead of general natural resources but a little behind the broad equity market.

We believe that energy equities have underperformed the broad market this year because various factors are misunderstood. Principally, we think that energy equity valuations reflect an expectation that international oil prices return in the longer term to around $80 (driven by concerns of oversupply), something we do not expect to happen, based on the fundamentals for the commodity.

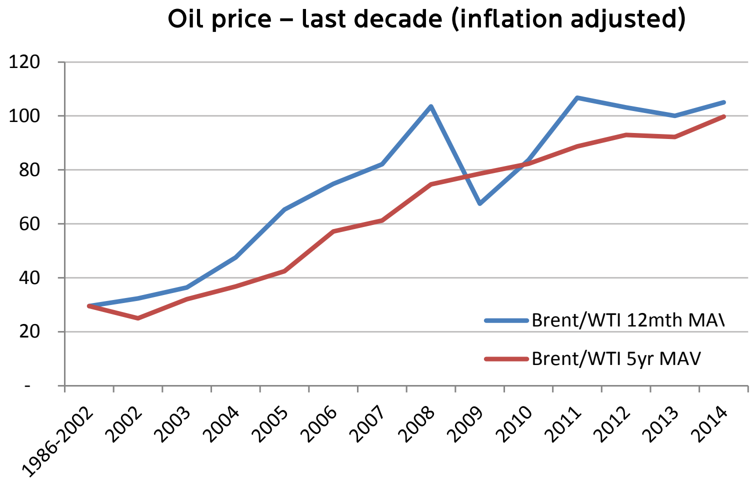
As a result, on traditional metrics of P/E ratio, price to discounted cash flow (e.g. the SEC's PV-10 calculation) or Enterprise Value to Reserves, many energy companies are at historically low levels. The 2013 P/E ratio of our Fund at July 31 is 11.2x versus 15.6x for the S&P500.

Considering valuations another way, the graph below shows the price to book ratio of the energy sector relative to the S&P 500 since 1965 (in red). The ratio today is low and looks very attractive versus history. We also show the oil price in today's dollars (in blue). The only periods when the price to book ratio has been lower than today (1970; 1986; 1998) coincided with the oil price at extreme lows. This dislocation (directionally) over the last 24 months between the oil price and energy valuations is striking:



Source: Bernstein; Guinness Atkinson Asset Management

We expect the dislocation to correct when the current oil price and long-run market expectations come together. $100 oil is around where that could happen.



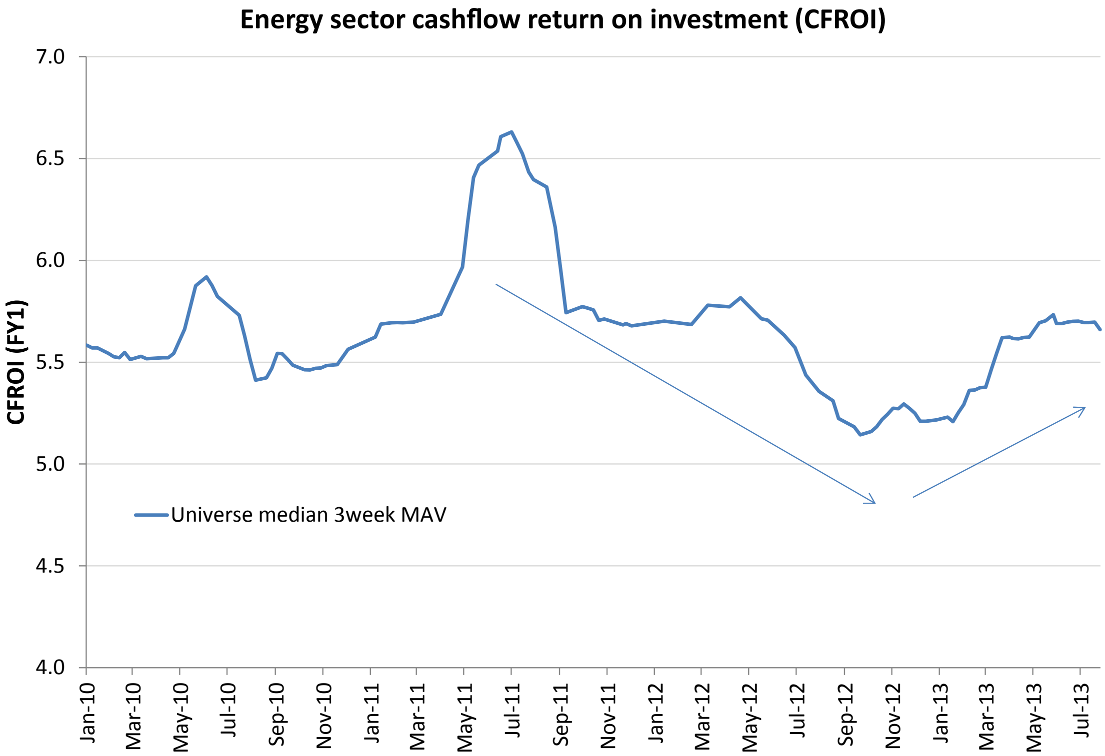
Oil Price (inflation adjusted)

12 month MAV	1986-2002	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	*2013* (*Forecast*)	*2014* (*Forecast*)
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)

Energy equity valuation sentiment

For considering a good entry point at which to buy energy equities the following may be helpful. Two of the energy sector specific headwinds over the last 24 months have been the pull back in oil price from the highs reached at the time of the Libyan crisis and more recently as embargoes were placed on Iranian exports; and the weakness in the US natural gas price which troughed a year ago. Earnings estimates (and cashflow return on investment) for energy companies as a result were generally trending down from mid-2011 to late 2012. A good entry point may well be when earnings estimates stop falling. We have been looking at this for several months and as the graph below indicates the most recent move is a trend higher. We hope that energy equities will follow.



Source: CSFB HOLT; Guinness Atkinson Asset Management

All this of course assumes the oil price stabilizes around the five 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 also remain 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 5.46% in July. The S&P 500 was up by 5.09% over the same period. The fund was up by 7.31% over this period, outperforming the MSCI World Energy Index by 1.85% (all in US dollar terms).

Within the fund, July's stronger performers were JA Solar, Trina Solar, Gazprom, Chesapeake and ShawCor. Poorer performers were Apache, OMV, BP, Patterson and Valero.

Performance as of June 30, 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%	12.61%	-8.01%	-5.24%	11.80%
MSCI World Energy Index	26.98%	12.73%	0.71%	2.54%	10.45%	-0.80%	-2.75%	9.41%
S&P 500 Index	26.47%	15.06%	2.09%	15.99%	20.75%	12.83%	7.05%	6.14%

Performance as of July 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%	15.10%	-4.71%	-0.57%	12.54%
MSCI World Energy Index	26.98%	12.73%	0.71%	2.54%	12.66%	1.72%	1.22%	9.96%
S&P 500 Index	26.47%	15.06%	2.09%	15.99%	24.98%	16.69%	8.24%	6.57%

Source: Bloomberg
Gross expense ratio: 1.35%

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 July.

Sector Breakdown

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

(%)	31 Dec 2007	31 Dec 2008	31 Dec 2009	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Jul 2013	*Change YTD*
Oil & Gas	**103.5**	**96.4**	**96.1**	**93.2**	**98.5**	**98.6**	**96.7**	***-1.9***
Integrated	66.2	53.7	47.2	41.2	39.6	39.1	38.4	*-0.7*
Exploration and production	25.8	28.7	32.0	36.9	41.5	41.6	38.5	*-3.1*
Drilling	8.1	5.2	8.4	6.3	6.0	7.4	6.3	*-1.1*
Equipment and services	3.4	6.4	5.4	5.3	6.6	7.1	10.5	*3.4*
Refining and marketing	0.0	2.4	3.1	3.5	4.8	3.4	3.0	*-0.4*
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**	**2.9**	**1.7**
Construction and engineering	**0.0**	**0.4**	**0.4**	**0.4**	**0.4**	**0.6**	**0.8**	**0.2**
Cash	**-6.0**	**0.9**	**3.5**	**3.2**	**-0.1**	**-0.4**	**-0.4**	**0.0**
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 July 31, 2013 was on an average price to earnings ratio (PE) versus the S&P 500 Index at 1,686 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, $96.8 for 2012 and $108.3 for 2013). This is shown in the following table:

	2007	2008	2009	2010	2011	2012	2013
Fund PER	8.9	7.9	15.3	9.9	9.9	11.1	11.2
S&P 500 PER	20.4	34.0	29.6	20.1	17.5	17.4	15.6
Premium (+) / Discount (-)	*-56%*	*-77%*	*-48%*	*-51%*	*-43%*	*-36%*	*-28%*
Average oil price (WTI $)	$72.2/bbl	$99.9/bbl	$61.9/bbl	$79.5/bbl	$95/bbl	$94/bbl	$96/bbl

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

Portfolio Holdings

Our integrated and similar stock exposure (c.38%) 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 July 31 2013 the median PE ratio of this group was 8.1x 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 10.1x 2012 earnings given the company's good growth prospects.

Our exploration and production holdings (c.37%) 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, Carrizo, Ultra and Stone all with quite low PEs (9x – 15x 2013 earnings); and (ii) Noble, Bill Barrett, Penn Virginia and QEP with higher PE ratios. However, all look reasonably attractive on EV/EBITDA multiples.

We have exposure to four (pure) emerging market stocks in the main portfolio, though all but one are half-positions. Two are classified as integrateds by the GICS (Gazprom and PetroChina) and two as E&P companies (Dragon Oil 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 2.6x 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 7.5x 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.

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 11.1x and 10.9x 2012 earnings) and those which operate in the US and internationally (Helix, Halliburton and Shawcor on 13.6x – 20.7x 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 sharp falls in solar prices during the year but the prospects for a return to profitability over the next 12 months are improving. 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 2.2x and 1.2x respectively.

Portfolio at July 31, 2013

Guinness Atkinson Global Energy Fund 31 July 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	3.41	14.31	12.9	11.1	24.1	15.7	11.1	11.9	12.1
Chevron Corp	US1667641005	USD	US	3.59	16.1	14.3	11.1	24.5	13.5	9.4	10.2	10.3
Royal Dutch Shell PLC	GB00B03MLX29	EUR	NL	3.44	8.5	6.8	7.8	15.1	11.0	8.1	8.1	8.1
BP PLC	GB0007980591	GBP	GB	3.19	6.3	6.3	5.1	8.8	6.1	6.1	7.6	8.7
Total SA	FR0000120271	EUR	FR	3.53	7.3	7.4	6.4	11.6	8.6	7.7	7.3	7.9
ENI SpA	IT0003132476	EUR	IT	3.26	5.9	6.4	5.9	11.7	8.8	8.5	8.3	10.4
Statoil ASA	NO0010096985	NOK	NO	3.12	6.8	9.3	7.0	12.7	9.5	8.2	7.7	8.7
Hess Corp	US42809H1077	USD	US	3.44	13.5	12.5	10.2	38.9	14.4	12.4	12.6	11.5
OMV AG	AT0000743059	EUR	AT	3.11	6.5	6.3	5.2	13.4	8.3	10.4	7.3	7.5
				30.10								
Integrated Oil & Gas - Canada												
Suncor Energy Inc	CA8672241079	CAD	CA	3.48	13.2	13.6	10.2	30.7	20.5	9.1	10.1	10.6
Canadian Natural Resources Ltd	CA1363851017	CAD	CA	3.18	21.8	15.1	9.7	13.2	13.1	13.8	20.0	14.3
				6.66								
Integrated Oil & Gas - Emerging market												
PetroChina Co Ltd	CNE1000003W8	HKD	HK	3.23	9.1	8.8	11.4	12.1	9.7	9.5	11.0	10.1
Gazprom OAO	US3682872078	USD	RU	1.65	4.8	4.6	4.0	4.6	3.6	2.5	2.6	2.8
				4.88								
Oil & Gas E&P												
ConocoPhillips	US20825C1045	USD	US	3.58	6.54	6.70	6.08	17.93	10.94	7.63	11.37	11.41
Apache Corp	US0374111054	USD	US	3.13	11.0	9.3	7.2	14.4	8.6	6.8	8.4	9.8
Bill Barrett Corp	US06846N1046	USD	US	1.07	15.8	23.1	8.2	13.2	11.1	12.7	423.0	nm
QEP Resources Inc	US74733V1008	USD	US	1.19	nm	nm	nm	nm	22.1	18.6	24.5	20.4
Ultra Petroleum Corp	CA9039141093	USD	US	1.17	15.1	19.0	8.2	12.0	9.7	8.5	11.7	13.2
Devon Energy Corp	US25179M1036	USD	US	3.32	8.7	7.9	5.6	15.2	9.3	9.1	17.0	14.2
Chesapeake Energy Corp	US1651671075	USD	US	3.60	6.5	7.3	6.6	9.4	8.0	8.3	48.0	15.0
Noble Energy Inc	US6550441058	USD	US	3.23	33.0	23.0	17.7	36.9	30.2	23.8	27.3	17.9
Newfield Exploration Co	US6512901082	USD	US	3.08	7.0	7.6	7.8	4.8	5.3	6.0	10.1	14.5
Stone Energy Corp	US8616421066	USD	US	1.63	8.9	4.7	4.4	10.6	12.0	6.3	8.8	8.5
Carrizo Oil & Gas Inc	US1445771033	USD	US	1.68	44.6	45.2	17.6	21.5	24.9	30.8	21.7	13.3
Penn Virginia Corp	US7078821060	USD	US	1.62	2.8	2.8	2.0	nm	nm	nm	nm	nm
Trinity Exploration & Production PLC	GB00B8JG4R91	GBP	GB	0.24	nm	nm	nm	nm	nm	nm	nm	10.8
Ophir Energy PLC	GB00B24CT194	GBP	GB	0.79	nm	nm	nm	nm	nm	nm	nm	nm
Triangle Petroleum Corp	US89600B2016	USD	US	0.78	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	0.17	nm	nm	nm	nm	nm	nm	nm	nm
				30.36								
Oil & Gas E&P - Emerging markets												
Dragon Oil PLC	IE0000590798	GBP	GB	1.71	26.6	15.8	13.1	19.0	13.8	7.4	7.5	7.4
Soco International PLC	GB00B572ZV91	GBP	GB	1.74	52.9	48.7	52.3	32.6	45.0	29.0	8.1	7.6
JKX Oil & Gas PLC	GB0004697420	GBP	GB	0.76	1.9	1.5	1.9	2.0	2.3	2.7	3.7	3.9
WesternZagros Resources Ltd	CA9600081009	CAD	CA	0.71	nm	nm	nm	nm	nm	nm	nm	nm
				4.92								
Drilling												
Patterson-UTI Energy Inc	US7034811015	USD	US	2.97	4.9	7.8	8.4	nm	29.2	9.2	11.1	15.6
Unit Corp	US9092181091	USD	US	3.34	6.7	7.9	6.6	17.1	14.8	11.0	10.9	12.0
				6.31								
Equipment & Services												
Halliburton Co	US4062161017	USD	US	3.60	20.6	17.8	20.8	34.5	22.5	13.5	15.2	14.1
Helix Energy Solutions Group Inc	US42330P1075	USD	US	3.35	8.9	7.6	10.4	43.7	48.0	16.9	13.6	24.9
ShawCor Ltd	CA8204391079	CAD	CA	3.49	36.9	28.8	23.8	25.3	37.0	63.2	20.7	10.4
Shandong Molong Petroleum Machinery Co Ltd	CNE1000001N1	HKD	HK	0.07	8.3	5.8	3.9	10.7	4.2	5.8	nm	nm
				10.52								
Solar												
Trina Solar Ltd	US89628E1047	USD	US	1.52	nm	10.2	6.1	4.5	2.2	274.8	nm	nm
JA Solar Holdings Co Ltd	US4660902069	USD	US	1.42	10.6	28.6	42.3	nm	1.2	nm	nm	nm
				2.95								
Oil & Gas Refining & Marketing												
Valero Energy Corp	US91913Y1001	USD	US	2.96	4.3	4.6	6.6	nm	22.5	9.0	7.3	8.4
				2.96								
Construction & Engineering												
Kentz Corp Ltd	JE00B28ZGP75	GBP	GB	0.76	nm	25.7	26.0	25.6	17.6	13.3	11.3	9.8
			Cash	-0.43								
			Total	100								
				PER	9.1	8.9	7.9	15.3	9.9	9.9	11.1	11.2
				Med. PER	8.9	8.8	7.8	14.4	11.1	9.1	10.9	10.5
				Ex-gas PER	9.3	9.2	8.6	16.8	10.0	10.1	10.2	10.5

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 and (for the first time) 2014.

	2004	2005	2006	2007	2008	*2009*	2010	2011	2012	2013e *IEA*	2014e *IEA*
World Demand	82.5	84.0	85.2	87.0	86.5	85.5	88.3	88.9	89.8	*90.8*	*92.0*
Non-OPEC supply (includes Angola and Ecuador for periods when each country was outside OPEC[1])	50.3	50.4	51.3	50.5	49.6	51.4	52.7	52.8	53.4	*54.6*	*55.9*
Angola supply adjustment[1]	-1.0	-1.2	-1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ecuador supply adjustment[1]	-0.5	-0.5	-0.5	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indonesia supply adjustment[2]	1.0	0.9	0.9	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-OPEC supply (ex. Angola/Ecuador and inc. Indonesia for all periods)	49.8	49.6	50.3	51.0	50.6	51.4	52.7	52.8	53.4	54.6	55.9
OPEC NGLs	4.2	4.3	4.3	4.3	4.5	5.1	5.6	5.9	6.3	*6.6*	*6.7*
Non-OPEC supply plus OPEC NGLs (ex. Angola/Ecuador and inc. Indonesia for all periods)	54.0	53.9	54.6	55.3	55.1	56.5	58.3	58.7	59.7	61.2	62.6
Call on OPEC-12[3]	28.5	30.1	30.6	31.7	31.4	29.0	30.0	30.2	30.1	29.6	29.4
Iraq supply adjustment[4]	-2.0	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.7	-3.0	-3.2	-3.2
Call on OPEC-11[5]	26.5	28.3	28.7	29.6	29.0	26.6	27.6	27.5	27.2	26.4	26.2

[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: 11 July 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 further rises in demand of 1.0m b/day in 2013 and 1.2m b/day in 2014, which would take oil demand to a new all-time high of 92.0m b/day.

OPEC

Five 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). From 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 (a change of leadership), 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. July 2013 production for OPEC-11 is reported to be around 27.6m b/day, indicating that OPEC are slightly higher but 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 May 2013 and no changes to production levels were made. Little new came out of the conference, with OPEC reiterating its desire to "achieve a stable oil market by ensuring that the market is well supplied to meet demand from consumers at fair and reasonable prices". The next meeting is scheduled for December 2013.

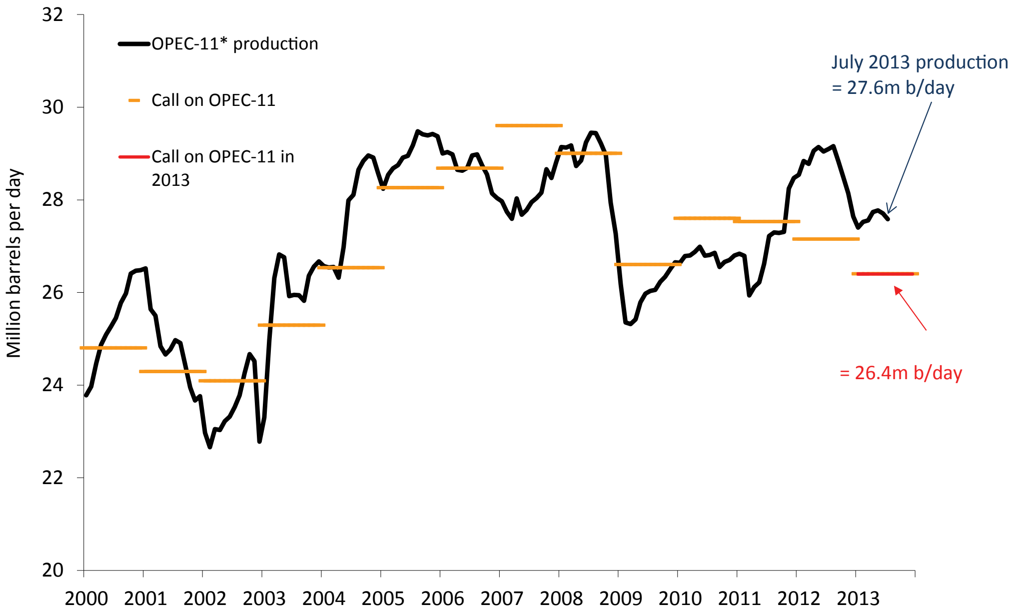
The table below shows changes in production among OPEC-12 since the end of 2010 and shows how production is running well ahead of pre-MENA unrest levels. In addition to the non-OPEC problems mentioned above, Saudi Arabia's increased production is an indication of their desire to see US and European sanctions 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 1.4m b/day, and total OPEC-12 production is 1.5m b/day higher than December 2010.

('000 b/day)	31-Dec-10	31-Jul-13	Change
Saudi	8,250	9,650	1,400
Iran	3,700	2,560	-1,140
UAE	2,310	2,800	490
Kuwait	2,300	3,000	700
Nigeria	2,220	1,920	-300
Venezuela	2,190	2,695	505
Angola	1,700	1,780	80
Libya	1,585	800	-785
Algeria	1,260	1,120	-140
Qatar	820	730	-90
Ecuador	465	527	62
OPEC-11	26,800	27,582	782
Iraq	2,385	3,080	695
OPEC-12	29,185	30,662	1,477

Source: Bloomberg LP (July 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 27.6m 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 6: OPEC apparent production vs. call on OPEC 2000 – 2013



Source: Bloomberg/IEA Oil Market Report (July 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 (+1.8m b/day over 2 years), implying that the rest of the non-OPEC region has declined by 0.9m 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 1.2m b/day in 2013, driven again by North American supply (+1.0m b/day). Other areas expected to grow their production include Russia, Colombia and China, offset by declines in the North Sea and Mexico. Should the IEA's forecast for 2013 be achieved, it would represent the highest level of non-OPEC supply growth since 2010.

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, modest 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 3.1m b/day in July 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 2.0m 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 comments from the management of Core Laboratories, a leading reservoir analysis company, that the market is overestimating the prospectivity of US oil shale. We also observe that since the discovery of the Bakken, Eagleford and Permian, the US has struggled to find another large shale resource, despite 3 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 1.4m b/day and a decline in OECD demand of 0.5m b/day. The non-OECD growth forecast for 2013 is similar to 2012 at 1.3m b/day. 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**	**2013**	**2010**	**2011**	**2012**	**2013**
Asia	18.25	19.70	20.28	20.96	21.62	1.45	0.58	0.68	0.66
M. East	7.10	7.32	7.39	7.63	7.81	0.22	0.07	0.24	0.18
Lat. Am.	5.70	6.03	6.29	6.52	6.70	0.33	0.26	0.23	0.18
FSU	4.00	4.15	4.36	4.49	4.60	0.15	0.21	0.13	0.11
Africa	3.37	3.48	3.38	3.52	3.67	0.11	-0.10	0.14	0.15
Europe	0.70	0.68	0.69	0.71	0.71	-0.02	0.01	0.02	0.00
	39.12	**41.36**	**42.39**	**43.83**	**45.11**	**2.24**	**1.03**	**1.44**	**1.28**

Source: IEA Oil Market Report (July 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 in 2013 is likely to almost match that in Asia. These other non-OECD regions are all central to the developing world industrialisation and urbanisation thesis and should not be overlooked.

For OECD demand in 2013, the IEA's forecast of a decline of 0.3m 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, but is shallower than predicted earlier this year, while the Pacific decline reflects the gradual switching back to nuclear by Japan post Fukushima.

Global oil demand over the next few years is likely to follow a similar pattern, with a shallow decline in the OECD overshadowed by strong growth in the non-OECD area. The small decline in the OECD reflects improving oil efficiency over time, though this effect will be dampened by economic, 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 non-OECD 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 summarizes 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 8: 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 likely 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).

This year, non-OPEC supply is growing better than at any point over the last three years, but is being countered by supply disruption across North and West Africa (Libya, Nigeria & Algeria) and the Middle East (Syria, Yemen and foremost, Iran). Factor in respectable demand growth and the market looks balanced, though we should recognise that we are only one ill-judged military move away from another oil spike.

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). So far, they are succeeding.

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 have 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

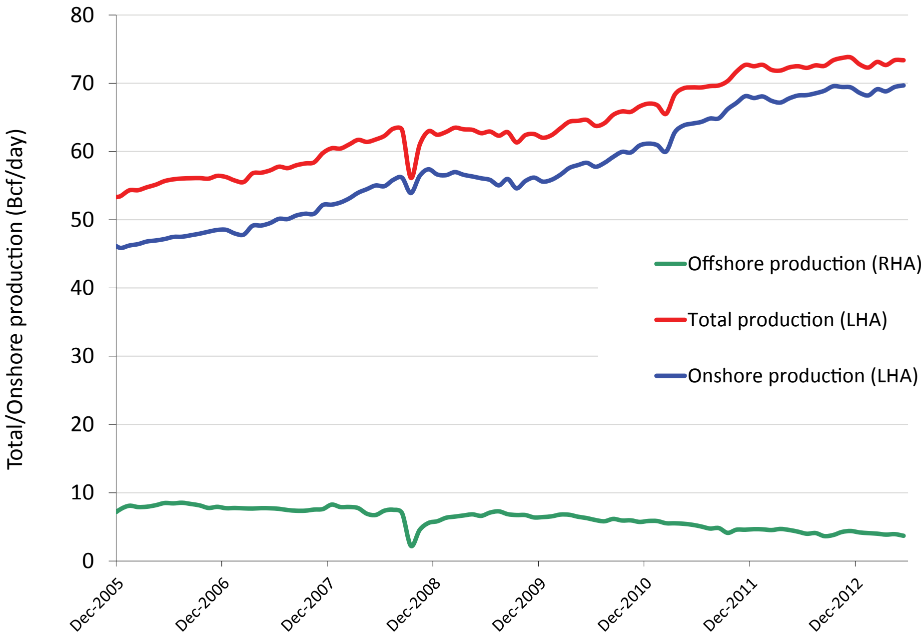
The onshore drilling rig count is the key driver of gas supply. When looking at changing totals, however, the accelerating shift from vertical to horizontal drilling has to be factored in as too does growing associated gas from rising onshore oil production, itself linked to a rising US oil rig count.

In total, the onshore gas rig count has dropped from a 1,606 peak in September 2008 to 353 at end-June 2013. Over the same period the oil rig count has risen from 416 to 1,390. The total number of rigs has therefore declined recently but not changed dramatically (it has gone from 2,031 Aug 2008 to 1,990 Sep 2011 to 1,748 June 2013). Within this, however, the mix has changed as illustrated by the following table:

RIG COUNT BHI	Aug 2008		Sep 2011		Jul 2013	
Gas Rigs	1606		923		369	
Oil Rigs	416		1060		1401	
Misc Rigs	9		7		6	
Total Rigs	**2031**		**1990**		**1776**	
		%		%		%
Horizontal Rigs	626	*31%*	1135	*57%*	1067	*60%*
Directional Rigs	388	*19%*	238	*12%*	287	*16%*
Vertical Rigs	1017	*50%*	617	*31%*	422	*24%*
Total Rigs	**2031**	*100%*	**1990**	*100%*	**1776**	*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 significantly) and is now at c. 69.7 Bcf/day, around 12.3 Bcf/day (20%) 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 – 2013 (Lower 48 States)



Source: EIA 914 data (May 2013 published in July 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 – edged up in July and remains at a very significant premium to the US gas price ($10.20 versus $3.46). 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 July 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

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, Guinness Atkinson Asset Management (July 2013)

#	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 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.

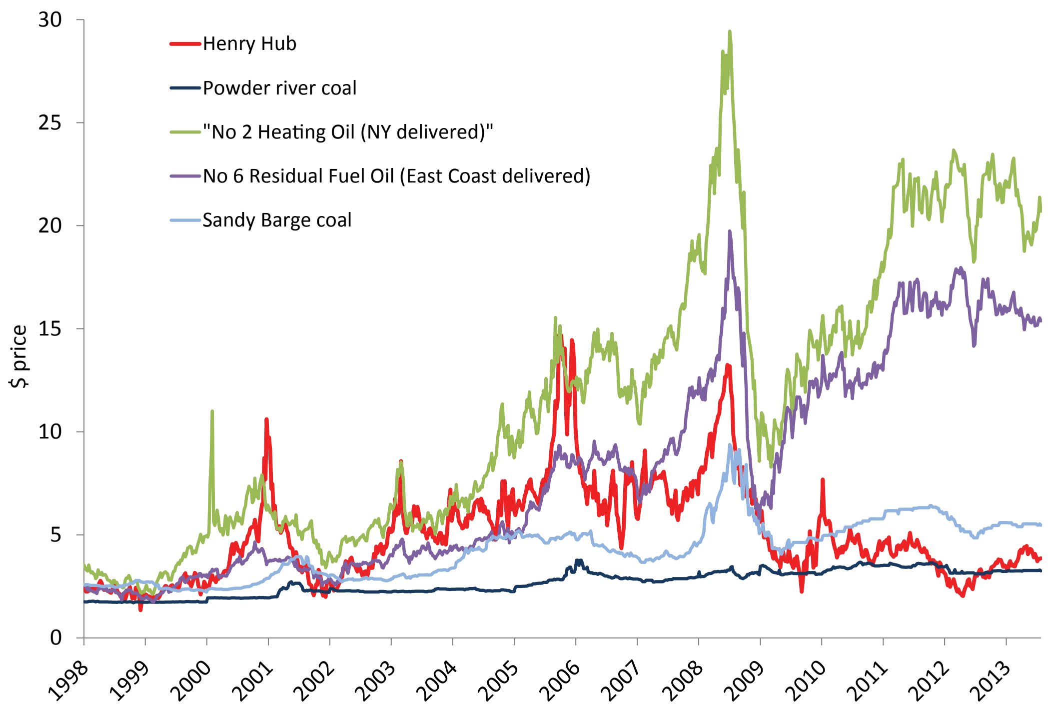
Other

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 30.4x at the end of July continues well outside the more normal ratio of 6-9x. If the oil price averages around $95 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 generally above $3.50/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 (July 31 2013)

Conclusions about US natural gas

We think the US natural gas price bottomed in 2012 and the recovery has begun. Natural gas at around $3.50 spot is nearly 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 11: 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.

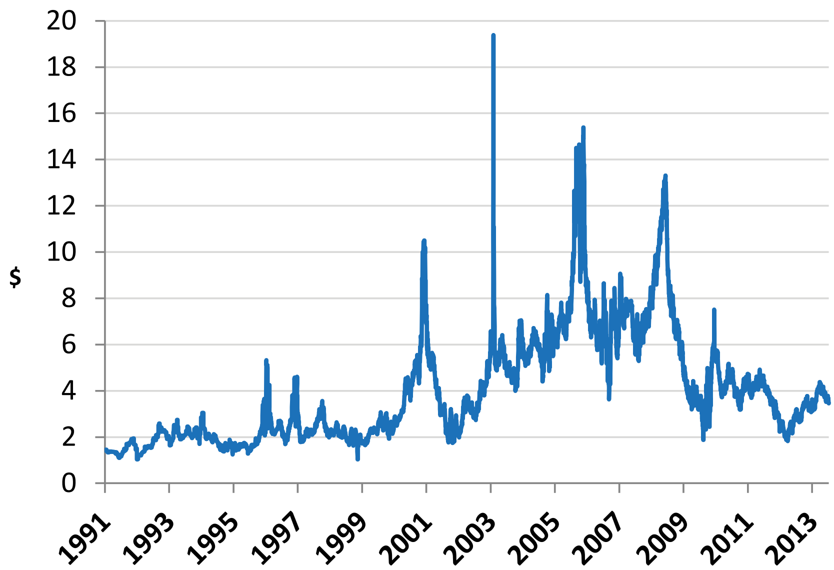
Then, in late 2002 early 2003, war in Iraq and a general strike in Venezuela caused the price to spike upward. This was quickly followed by a sharp sell-off due to the swift capture of Iraq's Southern oil fields by Allied Forces and expectation that they would win easily. Then higher prices were generated 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 12: 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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Mutual fund investing involves risk and loss of principal is possible. The Fund invests in foreign securities which will involve greater volatility, political, economic and currency risks and differences in accounting methods. The Fund is non-diversified meaning it concentrates its assets in fewer individual holdings than a diversified fund. Therefore, the Fund is more exposed to individual stock volatility than a diversified fund. The Fund also invests in smaller companies, which involve additional risks such as limited liquidity and greater volatility. The Fund's focus on the energy sector to the exclusion of other sectors exposes the Fund to greater market risk and potential monetary losses than if the Fund's assets were diversified among various sectors. The decline in the prices of energy (oil, gas, electricity) or alternative energy supplies would likely have a negative affect on the funds holdings.

MSCI World Energy Index is the energy sector of the MSCI World Index (an unmanaged index composed of more than 1400 stocks listed in the US, Europe, Canada, Australia, New Zealand, and the Far East) and as such can be used as a broad measurement of the performance of energy stocks. Indices do not incur expenses and are not available for investment.

The S&P 500 Index is a broad based unmanaged index of 500 stocks, which is widely recognized as representative of the equity market in general.

One cannot invest directly in an index.

Price to earnings (P/E) ratio (PER) reflects the multiple of earnings at which a stock sells and is calculated by dividing current price of the stock by the company's trailing 12 months' earnings per share.

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

Book Value is the net asset value of a company, calculated by subtracting total liabilities from total assets.

Enterprise value (EV) is defined as the market capitalization of a company plus debt minus total cash and cash equivalents.

EV/EBITDA is EV divided by "Earnings Before Interest, Taxes, Depreciation and Amortization" (EBITDA)

EV/R is the enterprise ealue to revenue multiple and a measure of the value of a stock.

Cash Flow Return on Investment (CFROI) is a valuation model that assumes the stock market sets prices based on cash flow, not on corporate performance and earnings. CFROI is a proprietary metric prepared by HOLT, a division of Credit Suisse.

Price to Discounted Cash Flow (DCF) is a valuation method used to estimate the attractiveness of an investment opportunity and calculated by dividing current price of the stock by DCF, which is an analysis that uses future free cash flow projections and discounts them (most often using the weighted average cost of capital) to arrive at a present value.

Price to Book (P/B) Ratio is used to compare a stock's market value to its book value and is calculated by dividing the current closing price of the stock by the latest quarter's book value per share.

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