INVESTING IN HUMAN PROGRESS

GLOBAL ENERGY OUTLOOK

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INVESTMENT RESEARCH SERIES

AN INTRODUCTION

DEMAND

A rising and increasingly wealthy global population have been driving relentless growth in the consumption of energy, and the growth is projected to continue to well into the 21st century[1].

SUPPLY

Despite improvements in alternative supplies, fossil fuels are projected to remain the predominant world energy source for decades to come. However, the era of low-cost, easily extractable oil is over.

COMPANY PROFITS

Rising demand and depletion of low-cost supply have been pushing energy prices higher. This should create a favorable environment for companies with resource reserves and for their service providers and distributors.

INFLATION

Historically, we have seen energy prices as one of the drivers of inflation, which means that energy companies could be used as a potential long-term inflation hedge. If we see dollar inflation over the next decade, we would be surprised if oil and gas prices did not rise by a comparable percentage.

[1] International Energy Agency (IEA) 2013

THE 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 International Energy Agency (IEA) forecasts for 2014.

	2004	2005	2006	2007	2008	*2009*	2010	2011	2012	2013	2014e
										IEA	*IEA*
World Demand	**82.5**	**84.0**	**85.2**	**87.0**	**86.5**	**85.5**	**88.5**	**89.1**	**90.2**	***91.4***	***92.8***
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**	**52.9**	**53.4**	***54.7***	***56.2***
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**	**52.9**	**53.4**	**54.7**	**56.2**
OPEC NGLs	4.2	4.3	4.3	4.3	4.5	5.1	5.5	5.9	6.2	*6.3*	*6.5*
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**	**58.2**	**58.8**	**59.6**	**61.0**	**62.7**
Call on OPEC-12[3]	28.5	30.1	30.6	31.7	31.4	29.0	30.3	30.3	30.6	30.4	30.1
Iraq supply adjustment[4]	-2.0	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.7	-3.0	-3.1	-3.4
Call on OPEC-11[5]	**26.5**	**28.3**	**28.7**	**29.6**	**29.0**	**26.6**	**27.9**	**27.6**	**27.7**	**27.3**	**26.7**

[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 - 14: June 2014 Oil market Report

Global oil demand in 2013 was 4.4m b/day up on the pre-recession (2007) peak. This means the combined effect of the 2007/08 oil price spike and the 2008/09 recession was quite small and was been shrugged off remarkably quickly. The IEA forecast a further rise of 1.4m b/day in 2014, the largest rise since 2010, which would take oil demand to an all-time high of 92.8m b/day.

OPEC

Five years ago, in order to put a floor under a plunging oil price, Organization for Petroleum Exporting Countries (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 30m 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 30.0m b/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."***
>
> ***- OPEC, December 13, 2011***

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 three OPEC member countries – Libya (ongoing civil war), Iran (western sanctions over nuclear weapons development), Venezuela (a change of leadership)); (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.

We are now around two and a half years on from the establishment of the 30.0m b/day quota. Our view remains that it 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. June 2014 production for OPEC-11 is reported to be around 30.2m b/day by Bloomberg, indicating that OPEC production is in line with targets. 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 early June 2014 and no changes to production levels were made for the fifth consecutive meeting. Little new came out of the conference, with OPEC "noting the relative steadiness of prices in 2014 to date is an indication that the market is adequately supplied, with the periodic price fluctuations being more a reflaction of geopolitical tensions than a response to fundamentals". They also repeated their readiness to "take steps to ensure market balance". The next meeting is scheduled for November 2014.

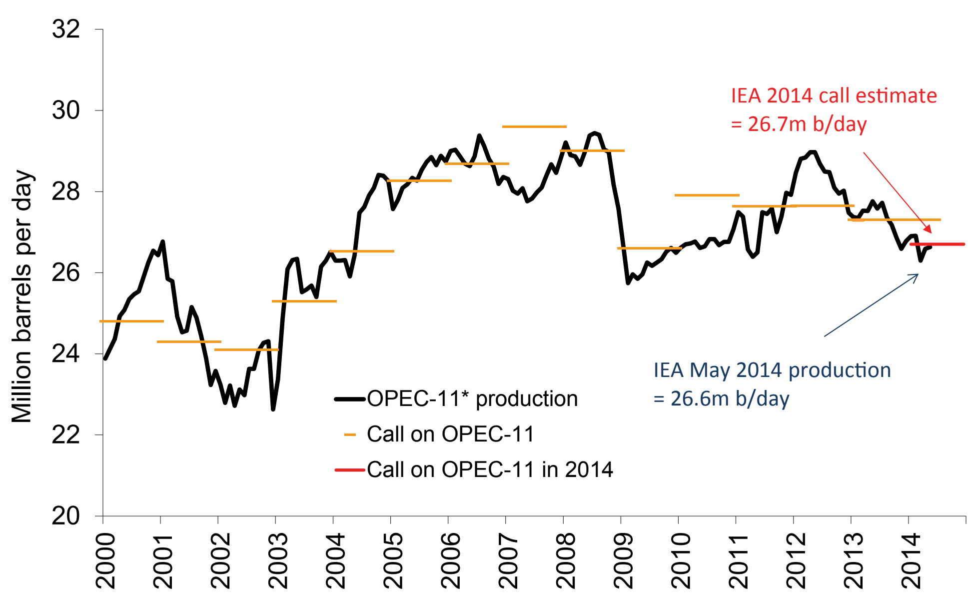
The table to the right shows changes in production among OPEC-12 s since the end of 2010 and shows how production is running well ahead of pre-MENA (Middle East and North Africa) unrest levels. Saudi production alone is up around 1.65m b/day at 9.9m b/day, having reached the highest production level for 32 years during summer 2013. We note that a full recovery in Libyan and Iranian production would bring a further c2.0m b/day back into OPEC supply. We are sceptical that this will occur anytime soon but should it occur, we expect that Saudi, United Arab Emirates (UAE) & Kuwait, who are supplying over 2m b/day over their long-term average, would compensate with a cut to their production.

('000 b/day)	31-Dec-10	30-Jun-14	Change
Saudi	8,250	**9,900**	1,650
Iran	3,700	**2,840**	-860
UAE	2,310	**2,800**	490
Kuwait	2,300	**2,800**	500
Nigeria	2,220	**2,150**	-70
Venezuela	2,190	**2,470**	280
Angola	1,700	**1,660**	-40
Libya	1,585	**300**	-1,285
Algeria	1,260	**1,125**	-135
Qatar	820	**725**	-95
Ecuador	465	**553**	88
OPEC-11	**26,800**	**27,323**	**523**
Iraq	2,385	2,900	515
OPEC-12	**29,185**	**30,223**	**1,038**

Source: Bloomberg

The graph below shows the estimated call on OPEC-11 for 2014, which we currently estimate to be around 26.7m b/day versus apparent production of 26.6m b/day in May (according to the IEA). Given that the overall market has tightened over the last few months up until the end of April 2014, it suggests that the actual call has recently been higher than 26.7m b/day. The gap can most likely be bridged via 'missing' demand (a reference to non-OECD demand, in particular, being higher than the IEA are reporting) and overstated non-OPEC supply.

Figure 1: OPEC apparent production vs call on OPEC 2000 – 2014



Source: IEA Oil Market Report (June 2014 and prior)

SUPPLY LOOKING FORWARD

The non-OPEC world has, in recent years, struggled to grow production meaningfully. The growth was 2.0% per annum (p.a.) from 1998-2003, 0.2% p.a. from 2003-2008 and 2.0% p.a. from 2008-2013.
Non-OPEC production growth in 2013 (1.3m b/day) was the strongest since 2009. Nearly all of the growth in the non-OPEC region over the last 3 years has come from the successful development of shale oil and oil sands in North America (+3.1m b/day since 2010), implying that the rest of non-OPEC region has declined by 1.1m b/day over the period, despite the sustained high oil price.

The IEA estimates a further 1.5m b/day of growth in 2014. Whilst the IEA have a long history of over-optimism towards oil supply growth, it seems plausible that 2014 will see non-OPEC supply grow better than at any time over the last decade. The expected supply is dominated by North America (+1.2 m b/day) and supported in particular by Africa (+0.2m b/day). Should non-OPEC supply grow this strongly in 2014, we expect it to have a small loosening effect on the global oil balance, with the growth absorbed by rising demand and a slight reduction in OPEC supply.

Looking further ahead, we must consider in particular 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 how other OPEC members react are all important issues. Our conclusion is that while an increase in Iraqi production may be technically possible (say, 2m barrels per day 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 2.4m b/day in June 2014 (according to Bloomberg), down from a high of 3.6m b/day in mid-2000. Despite this potential, the recent unrest in the country and a continued lack of required infrastructure does not fill us with confidence that growth can easily be achieved. It is unlikely that large oil companies will choose to invest significant sums into Iraq unless there is much greater political stability.

Non-OPEC production growth, 1.3 million b/day in 2013, was the strongest since 2009. The IEA estimates a further 1.5 million b/day of growth in 2014.

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 just over 3m 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 and attractive for North American producers to develop. In total, it could be comparable in size to the UK North Sea, i.e. it could grow by around a further 3m b/day over the next five years. 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.

Other 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 being 5-10 years behind North America.

DEMAND LOOKING FORWARD

The IEA reported growth in oil demand in 2013 of 1.2m b/day, comprising an increase in non-OECD (Organisation for Economic Co-operation and Development) demand of around 1.2m b/day and a small increase in OECD demand of just under 0.1m b/day. The components of this non-OECD demand growth can be summarized as follows:

Figure 2: Non-OECD oil demand

m b/d	Demand						Growth				
	2009	**2010**	**2011**	**2012**	**2013**	**2014e**	**2010**	**2011**	**2012**	**2013**	**2014**
Asia	18.25	19.70	20.35	21.28	21.80	22.51	1.45	0.65	0.93	0.52	0.71
M. East	7.10	7.32	7.43	7.75	7.96	8.22	0.22	0.11	0.32	0.21	0.26
Lat. Am.	5.70	6.03	6.17	6.39	6.59	6.77	0.33	0.14	0.22	0.20	0.18
FSU	4.00	4.15	4.39	4.49	4.61	4.69	0.15	0.24	0.10	0.12	0.07
Africa	3.37	3.48	3.48	3.63	3.74	3.91	0.11	0.00	0.15	0.11	0.17
Europe	0.70	0.68	0.66	0.67	0.68	0.69	-0.02	-0.02	0.01	0.01	0.01
	39.12	**41.36**	**42.48**	**44.21**	**45.38**	**46.77**	**2.24**	**1.12**	**1.73**	**1.17**	**1.39**

Source: IEA Oil Market Report (June 2014)

As can be seen, Asia has settled down into a steady pattern of growth since 2010. Collective growth in the Middle East, Latin America, FSU and Africa in 2013 almost exactly matched that in Asia. These other non-OECD regions are all central to the developing world industrialisation and urbanisation thesis: it is much more than just a China story. Looking into 2014, further non-OECD growth of 1.4m b/day is expected, the Asian component of this up on 2013 to 0.7m b/day (of which China represents 0.3m b/day).

For OECD demand in 2013, the IEA initially expected a decline but this was reversed to an overall rise of just over 0.1m b/day as North America came in far stronger than expected, up 0.4m b/day. European demand was down, reflecting weak economic expectations for the region, whilst a decline in the Pacific region reflects the gradual switching away from the temporary move to oil by Japan post Fukushima. OECD demand in 2014 is forecast to be down by 0.1m b/day, with North America up, Europe and Pacific down.

Global oil demand over the next few years is likely to follow a similar pattern, with a flat to shallow decline picture 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 summarises our view by showing our oil price forecasts for WTI and Brent in 2014 against their historic levels, and rises in percentage terms that we have seen in the period from 2002 to 2013.

Figure 3: Average WTI & Brent yearly prices, and changes

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014e
Average WTI ($)	31.2	41.7	56.6	66.1	72.2	99.9	61.9	79.5	95.0	94.1	98.0	**95**
Average Brent ($)	28.9	38.5	54.7	65.5	73.2	97.1	62.5	79.7	111.0	112.0	108.7	**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	103.4	**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	0.3	**-3.35**
Avge Change⁺ y-o-y (%)		33%	39%	18%	10%	35%	-37%	28%	29%	0%	0%	-3%

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

This year, non-OPEC supply is expected to grow 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 35% 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 2013 to around 20.2 Bcf/day.

Electricity gas demand (i.e. power generation) is affected by weather, in particular warm summers which drive demand for air conditioning, but the underlying trend depends on Gross Domestic Product (GDP) growth and the proportion of incremental new power generation each year that goes to natural gas versus the alternatives of coal, nuclear and renewables. Gas has been taking market share in this sector: in 2013, 27.2% of electricity generation is estimated to have been powered by gas, up from 21.6% in 2007. The big loser here is coal which has consistently lost market share over the past 10 years. Total gas demand in 2013 (including Canadian and Mexican exports) is estimated to have been 75.7 Bcf/day, up by 1.4 Bcf/day (1.9%) vs 2012 and up 6.5 Bcf/day (9%) vs the 5 year average. The biggest change in 2013 vs 2012 was in power generation (-2.6 Bcf/day), as much of the coal to gas switching seen in 2012 unwound as the gas price recovered. This, however, was more than offset by a rise in commercial demand (+2.4 Bcf/day), driven by a cold finish to the 2012/13 winter, and a rise in industrial demand (+0.7 Bcf/day).

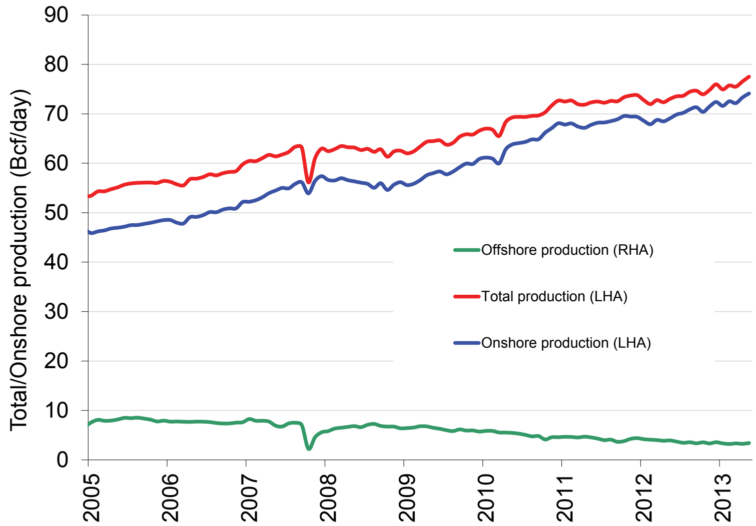
Overall, while gas demand in the US has been reasonably strong over the past four years, it has been trumped over this period by a rise in onshore supply, pulling the gas price lower.

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 weaker 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). Interestingly, the overall rise in onshore production has come despite a collapse in the number of rigs drilling for gas, which has dropped from a 1,606 peak in September 2008 to 314 at the end of June 2014. However, offsetting the fall, the average productivity per rig has risen dramatically as producers focus their attention on the most prolific shale basins. Onshore gas supply (gross) is now at 74.1 Bcf/day, around 16.7 Bcf/day (29%) above the 57.4 Bcf/d peak in 2009 before the rig count collapsed.

The trends in US onshore production were initially were mitigated by declining offshore production and

Figure 4: US natural gas production 2005 – 2014 (Lower 48 States)



Source: EIA 914 data (April 2014 published in June 2014)

falling net Canada and LNG imports and rising exports to Mexico. More recently, from about September 2011, the mitigating factors became exhausted and a net imbalance developed between supply and demand.

SUPPLY OUTLOOK

The outlook for gas production in the US depends on three key factors: the rise of associated gas (gas produced from wells classified as oil wells); expansion of the newer shale basins, principally the Marcellus, and the decline profile of legacy gas fields. If US onshore oil production grows by a further 2-3m b/day between now and 2017, we expect associated gas to grow by around 5-8 Bcf/day. The Marcellus, which is the largest producing gas field in the US, currently accounts for around 11 Bcf/day of supply. Further growth of 3-4 Bcf/day is likely over the next few years. Balanced against these increases is an expected decline in legacy gas fields, particularly if the gas drilling rig count stays low. We estimate that 'other gas' (onshore production ex associated and Marcellus) declined by around 4.5 Bcf/day in 2013. Declines in 2014 and beyond from 'other gas' may though moderate as declines from legacy fields flatten (a result of moving along the decline curve). Considering these factors together, we expect production gains to continue (c.1-3 Bcf/day per annum for the next two or three years), but with an inflection point in demand coming (see discussion below), higher production than may well be needed.

	2009	2010	2011	2012	2013	2014e
Onshore production - average (Bcf/day)	55.9	58.6	64.6	68.4	70.2	73.0
Change (Bcf/day)	0.9	2.70	6.00	3.80	1.80	2.80
Change (%)	1.7%	4.8%	10.2%	5.9%	2.6%	4.0%

Source: EIA; Guinness Atkinson estimates

Liquid natural gas (LNG) arbitrage

The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – weakened slightly in June, reflecting the lasting effect of a warm European winter and spring and relatively high levels of gas in inventory. We note that it still remains at a premium to the US gas price (c.$6.60 versus c.$4.50), albeit much reduced from 6 months ago. LNG supplies to the UK have been somewhat constrained, particularly in light of strong demand for LNG to Asian markets. US LNG imports remained well below 1 Bcf/day in May 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 5.0 Bcf/day (estimated) in 2013. The fall 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 and the depressed US price. We expect net imports in 2014 to remain around 5 Bcf/day.

DEMAND OUTLOOK

Assuming average temperatures for the rest of the year, we expect US total demand in 2014 (including exports to Canada and Mexico) to be just over 76 Bcf/day, around 1 Bcf/day higher than 2013. The very cold start to 2014 accounts for around 1 Bcf/day of this growth, so adjusting for weather, we expect to see underlying demand flat versus 2013. Demand from power generation is expected to decline slightly, as gas's long term capture of underlying market share from coal is tempered by shorter term gas to coal switching, assuming the gas price remains $4.50+. Residential and commercial gas demand for the rest of the year will as ever be weather dependent, but assuming average temperatures, demand should be about unchanged from 2013. And we expect industrial consumption about 0.9 Bcf/day above 2013.

Looking out further, the low US gas price has stimulated various initiatives that are likely have a material impact on demand from 2016 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 27 bcf/day in Canada, as shown below:

Proposed NAM LNG export terminals

	Number of terminals	Non-FTA approval (bcf/day)
US – Export approved	7	9.3
US – FERC review	2	3.1
US – Proposed	7	12.9
US - Total	**16**	**26.4**
Canada – NEB export approved	7	15.2
Canada – Proposed	3	12.2
Canada - Total	**10**	**27.4**
North America - Total	**26**	**53.8**

Source: Bernstein, Guinness Atkinson Asset Management; NAM = North American

Location of proposed terminals

Not all the proposed facilities will be built but we think that exports of between 4-8 bcf/day from the US by 2020, or around 5-10% 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, a department of energy (DoE)-sponsored report concluded that LNG exports will have a net benefit to the US economy and that benefits are likely to increase as LNG exports rise.

Industrial demand will also grow thanks to the increased use of gas in the oil refining process and 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 also believe that gas will continue to take the majority of incremental power generation growth in the US and continue to take market share from coal. Coal fired power generation closures will be feature of 2014 and 2015 as Maximum Achievable Control Technology (MACT) standards come into force in an effort to reduce mercury and acid gases emissions, which likely accelerates the switch to gas. Our working assumption is for gas fired power generation to grow 0.8-1.5 Bcf/day per year.

Increased demand from natural gas vehicles (compressed natural gas typically for shorter haul and liquefied natural gas for longer haul journeys) is coming, but starts from such a small base that it is unlikely to contribute meaningfully to the overall demand picture in the next 5 years.

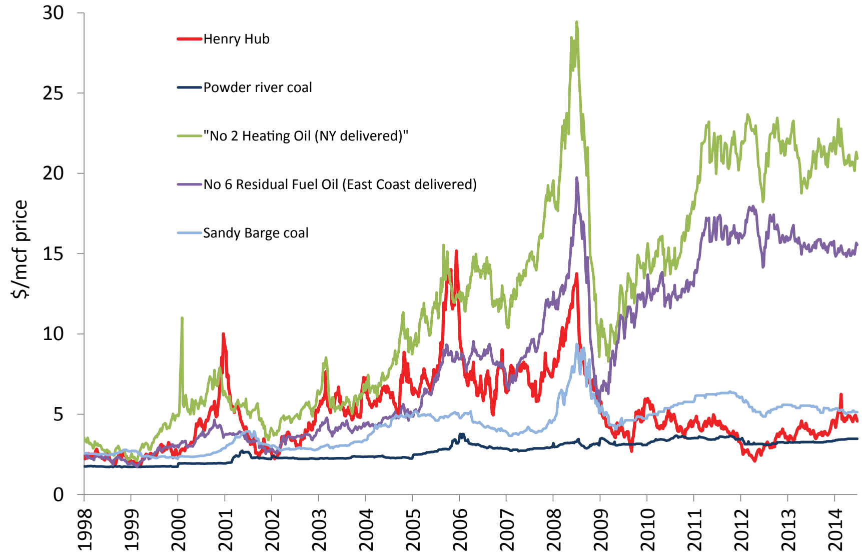
OTHER

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of 23.6x at the end of June continues well outside the more normal ratio of 6-9x. If the oil price averages around $95 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. Much of this short-term switching has now unwound again, though there is probably a little more to go if gas persists above $4/mcf. The recent increase in natural gas prices to over $4.50/mcf has not been met with significant switching to coal, so we will track the price sensitivity of that switching carefully from here.

Figure 5: Natural gas versus substitutes (fuel oil and coal)

Henry Hub vs residual fuel oil, heating oil, Sandy Barge (adjusted) and Powder River coal (adjusted)



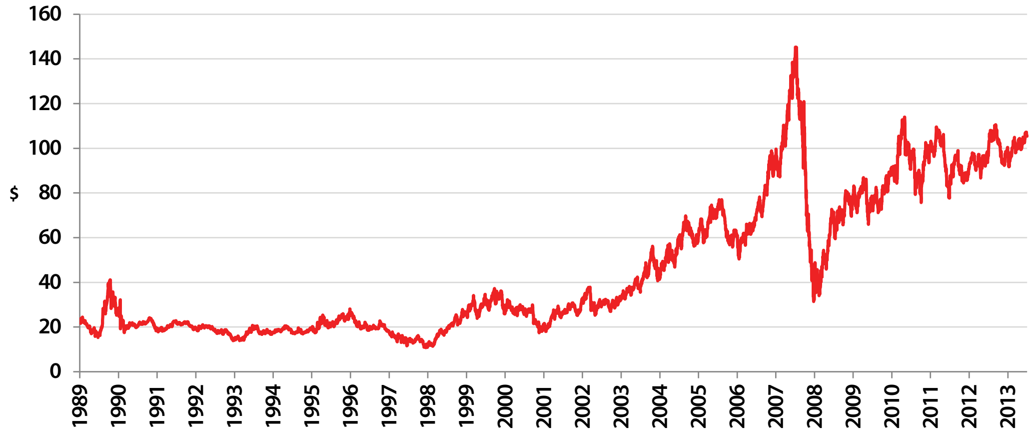
Source: Bloomberg LP (July 2014)

CONCLUSIONS ABOUT US NATURAL GAS

The US natural gas price bottomed in 2012 and the recovery is underway. Natural gas at around $4.50 (spot) is more than double the April 2012 low but still below the (full cycle) marginal cost of supply. We do not believe the excess in production over demand can continue indefinitely with natural gas trading at this level: a combination of reduced capital spending by the exploration companies and growing natural gas demand stimulated by the low gas price will rebalance the market, as is now happening. As this all happens we expect the price to stabilise in the $4-5 range. It may be held at this level for a period until demand grows further, and longer term we expect the price to normalize to $6-8.

APPENDIX: OIL AND GAS MARKETS HISTORICAL CONTEXT

Figure 6: Oil price (WTI $) last 24 years.



Source: Bloomberg LP

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.

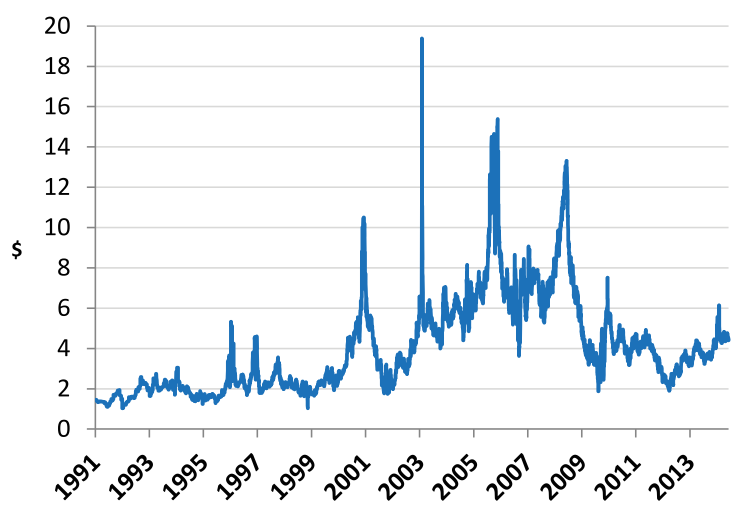
Then, in late 2002 early 2003, war in Iraq and a general strike in Venezuela caused the price to spike upward. This was quickly followed by a sharp sell-off due to the swift capture of Iraq's Southern oil fields by Allied Forces and expectation that they would win easily. Then higher prices were generated 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 7: North American gas price last 22 years (Henry Hub $/Mcf)



Source: Bloomberg LP

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.

ABOUT THE FUND MANAGERS

TIM GUINNESS
Lead Manager

Tim Guinness has served as Guinness Atkinson's Chairman and Chief Investment Officer since the firm's founding in November 2002. From 1999 to November 2002, he was Joint Chairman of Guinness Flight Global Asset Management, Ltd. and was the CEO from 1997 to 1999. Tim graduated from Cambridge University with a degree in engineering and completed a Master's Degree in Management Science at the Sloan School M.I.T. in the United States.

Will Riley
Co-manager

Joined Guinness Atkinson in May 2007, serving as a member of the energy investment team. In 2000 he joined Pricewaterhouse Coopers and in 2003 he qualified as a Chartered Accountant. Will graduated from Cambridge University with a Masters degree in Geography.

Jonathan Waghorn
Co-manager

Joined Guinness Atkinson Asset Management in 2013 after managing the Investec Global Energy Funds since 2008. He previously worked as energy analysts at Goldman Sachs International and Wood Mackenzie Global Consultants. Jonathan graduated from University of Bristol with a Masters degree in physics.

Monthly commentary about the Global Energy market is available at gafunds.com/ebriefs.

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The Fund's investment objectives, risks, charges and expenses must be considered carefully before investing. The statutory and summary prospectus contains this and other important information about the investment company, and it may be obtained by calling 800-915-6566 or visiting gafunds.com. Read it carefully before investing.

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Top 10 holdings for Global Energy Fund, as of 9/30/14: 1. ShawCor Ltd. 3.56% 2. Unit Corp 3.46% 3. John Wood Group PLC 3.45% 4. Total SA 3.44% 5. Hess Corp. Valero Energy Corp. 3.43% 6. Apache Corp 3.43% 7. Eni SpA 3.43% 8. Halliburton Co. 3.39% 9. Statoil ASA 3.38% 10. Royal Dutch Shell PLC 3.36%

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