

Shale oil and gas

US revolution, global evolution

US shale oil and gas production has surged in recent years, changing the global energy supply picture. The extent to which other countries follow suit will influence the world economy for years to come.



By Kevin Logan and the HSBC Research team

Disclosures and Disclaimer This report must be read with the disclosures and analyst certifications in the Disclosure appendix, and with the Disclaimer, which forms part of it

US revolution, global evolution

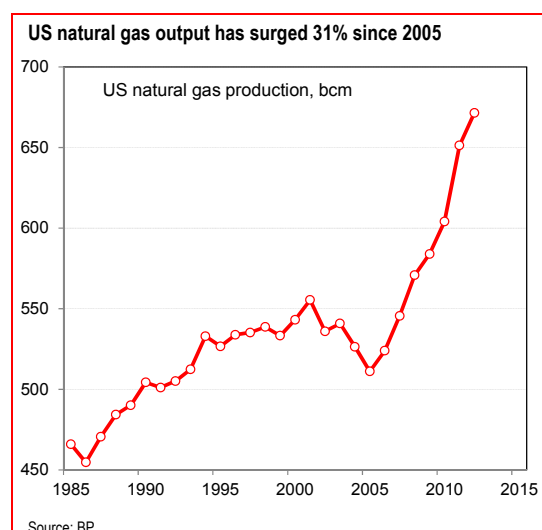
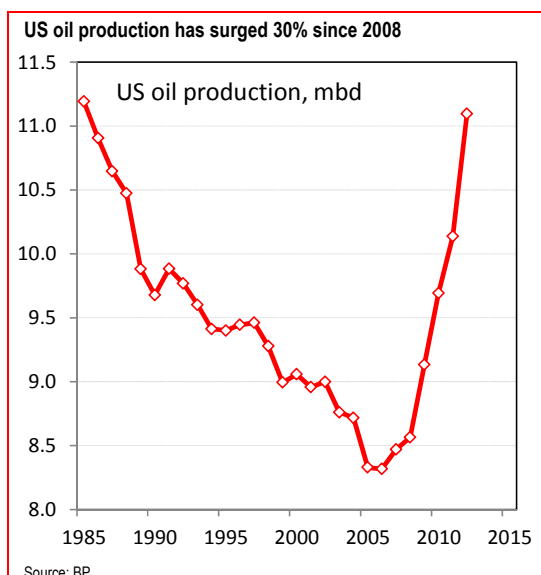
- ▶ Shale energy may be a revolution for US oil and gas...
- ▶ ...but it will have only a modest effect on the US economy...
- ▶ ...while its impact on the rest of the world will be, at best, an evolution

The shale effect

Unconventional oil and gas is not new. Oil shale was used in Mesopotamia as early as 3000BC for road construction, and the Athabasca tar sands in Canada were used in the 1700s by native Canadians to waterproof canoes.

Yet, it is only in the past five years that unconventional oil and gas – specifically, shale oil and gas – has become an energy source about which the whole world cares.

The shale “revolution,” however, is not quite all it seems. For all the excitement associated with this unconventional source of energy – promises of cheap oil and gas, the possibility of energy self-sufficiency for the US and, in time, a host of other countries – the reality is a little more sobering. The US energy sector has most certainly had a shot in the arm but the impact on the broader US economy is likely to be modest. Meanwhile, duplication of US energy advances elsewhere in the world is far from straightforward. For much of the world, harnessing shale energy will be more evolution than revolution.



Even as US energy consumption has faded, energy production has soared, thanks largely to the shale revolution. Yet, oil and gas extraction accounts for a mere 1.5% of GDP, suggesting that, even with substantial increases, the impact on the broader economy is likely to be modest as, indeed, it has been in recent years. We estimate that US growth will be 0.2-0.3% higher per year over the next decade or so than it would otherwise have been. That is not a great deal given the countervailing headwinds, notably a still-precarious medium-term fiscal outlook.

Shale gas – as opposed to oil – is the really big story in the US, one reason why domestic gas prices have plunged in recent years relative to both international gas prices and oil prices. The degree to which this price “gap” can be maintained is a subject of considerable debate, ultimately dependent on the extent to which liquid natural gas export facilities are constructed in the US in coming years. While energy companies will be keen to sell gas at the higher global price, others would prefer to keep gas at home for strategic reasons (and, it has to be said, to allow the US to benefit from a protectionist price “wedge”). In the meantime, other US industries stand to gain from the price discount: the more likely sectors to benefit include chemicals, plastics, metals, wood, and paper products. A transportation revolution may, however, be some years away and is likely to be restricted to commercial traffic.

This is a boom that is already affecting the US’s neighbors. Mexican manufacturers are clear winners, benefiting from lower electricity costs thanks to cheap imports of US gas. For Canada, the impact is more nuanced. On the one hand, Canadian oil producers have captured a greater share of the US market, upping their exports to the US by 20% over the past two years. But we expect the US shale gas boom, by reducing US

demand for imports of natural gas from Canada, will lead indirectly to increased Canadian gas supplies in Asian markets.

This is one example of the way that US shale is already affecting global oil supply trends and trade flows. US shale oil happens to be relatively light, with low sulphur content. So displacement of US oil imports by domestic crude means that OPEC producers of light, low-sulphur oil such as Algeria, Angola, and Nigeria have seen their exports to the US drop by more than 50% in just two years.

We estimate that increased US production has freed up 2mbd of oil for global markets. With faster-growing emerging markets still demanding more oil – the International Energy Agency (IEA) estimates that global oil demand will be 7mbd higher by 2018 relative to where it is now – this should help reduce any supply squeeze, but it is not enough.

The US is not the only nation blessed with plentiful reserves of unconventional energy. Yet it is one of the very few which has managed to turn shale potential into a fracking reality, thanks to a host of advantages. These include helpful geology, high-quality extractive skills, well-defined property rights, low population densities, plentiful water supplies, and the right incentives for landowners. Even in the US, however, some states are highly dubious about fracking technologies: Maryland, New York, and Vermont have banned fracking altogether. Their attitude is shared elsewhere in the world: France and Bulgaria have both refused to jump on the shale bandwagon, even as China, Poland, Canada, and the UK have shown considerable enthusiasm.

Still, even for the enthusiasts, there are problems. China struggles to marry its shale energy ambitions with its concerns about water supply: groundwater contamination is a real risk. Poland’s

Lubin Basin, which initially promised so much, now appears to be a case of too little gas, too much hot air. Unlike the US, the UK has a very high population density, suggesting that local opposition to exploration could be substantially higher. Argentina has plenty of reserves but, given its persistent abuse of property rights over the years, may struggle to attract the necessary foreign investment. The US has had a relatively easy ride: others will not be so lucky. And the “revolution” sits oddly with the environmental concerns linked to carbon dependency, not to mention the methane emissions specifically linked to the shale industry.

Beyond the economics, the environmental concerns, and geology lottery, there is also, of course, the tricky issue of geopolitics. An energy-self-sufficient US raises all sorts of questions for the Middle East and Russia, both of which have been major energy exporters in recent years.

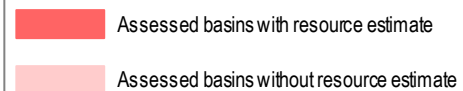
For the Middle East, the big question is the impact of greater US energy self-sufficiency on oil prices. A weaker OPEC could easily lead to a drop in oil prices to USD90 per barrel – which would force a re-think of current spending priorities – or even USD80 per barrel – which would seriously damage welfare provision in a region already suffering from political unrest and facing the prospect of a huge number of rebellious young mouths to feed. As for the geopolitics: any attempt by the US to withdraw from the Middle East risks creating a power vacuum that draws in other international powers – something that may already be shown by recent developments in Syria.

Russia’s main energy market is, for the time being, the European Union. With the rise of China, however, that story will change. By the middle of the century, we expect Asia to be Russia’s biggest consumer, pointing to further pipeline diplomacy in the coming years.

Key facts about shale

- ▶ US shale oil production is now 2.2mbd, from virtually nothing a decade ago.
- ▶ Shale gas in the US had grown to 32% of its natural gas production in 2012, from 5% in 2006.
- ▶ The US overtook Russia as the world’s biggest producer of natural gas in 2011.
- ▶ On the back of shale gas, the US is set to become a net exporter of gas by 2020, according to the Energy Information Administration (EIA).
- ▶ Increased US oil and gas production – mostly shale – should lower US reliance on energy imports; according to the EIA, the import share will fall to 10% in the next 15 years, from 24% in 2009.
- ▶ The EIA estimates that there are 345bn barrels of technically recoverable shale oil globally.
- ▶ The top 10 countries with technically recoverable shale oil resources are, in order: Russia, US, China, Argentina, Libya, Australia, Venezuela, Mexico, Pakistan, and Canada.
- ▶ The top 10 countries with technically recoverable shale gas resources are, in order: US, China, Argentina, Algeria, Canada, Mexico, Australia, South Africa, Russia, and Brazil.
- ▶ HSBC estimates that the shale oil and gas boom will add 0.2-0.3% per year to US GDP growth over the next five years.

Legend



Source: US Energy Information Administration

Contents

Shale and the US economy	6
Shale: The oil and gas view	15
Gas and oil substitution	23
Environmental concerns	26
Geographies	31
Argentina	32
Australia	36
Brazil	40
Canada	44
China	50
Mexico	54
Middle East	58
Poland	63
Russia	66
UK	70
Venezuela	74
Disclosure appendix	79
Disclaimer	80

Shale and the US economy

- ▶ Oil and gas volumes from US shale deposits have soared since 2008, and have changed the global energy supply picture
- ▶ With US demand for energy lagging supply growth, the shale oil and gas boom has reduced US energy import needs
- ▶ We estimate that the shale oil and gas boom will add 0.2-0.3% per year to US GDP growth over the next five years

Energy transition

The use of energy in the US is falling at the same time that production is increasing rapidly. This has led to less reliance on imports of energy and has put downward pressure on energy prices both in US and global markets.

In the US, the biggest impact has been on the price of natural gas. In global markets, the increased availability of crude oil produced in the US has put some downward pressure on benchmark prices of internationally traded crude oil and oil products, which has helped to ease constraints on global economic growth.

Though increased production is having a big effect on energy markets worldwide, it is having a smaller effect on economic growth within the US. The oil and gas industry is actually a small part of the overall US economy, with oil and gas extraction accounting for about 1.5% of GDP. Increased production in this sector, though substantial, is not enough to significantly change the overall economy's growth rate. We estimate that increased energy production will add between 0.1-0.2% to GDP annually over the next five years. On top of that, growth in industries like

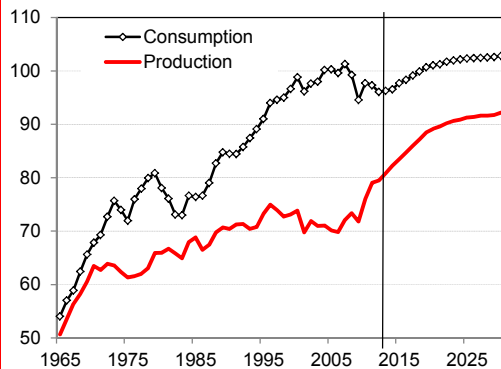
chemicals, which could benefit from cheaper gas, could add a further 0.1% per year to GDP growth over the next five years. Please also see 24 July 2012, [*US Shale Gas and Oil Boom: The USD100bn import bill swing*](#); 21 February 2013, [*US Oil Boom Revisited: Why consumers are missing out*](#); and 5 September 2013, [*Global Commodity Prices: More super, less cycle*](#).

Stagnant demand, increasing supply

The absolute amount of energy used in the US has fallen about 5% since 2007 (see chart overleaf). The decline came about because of the near-doubling of crude oil prices in 2008 and because of the deep recession in 2008/2009. However, since the economy is growing again and per capita income is rising modestly, further outright declines in energy demand seem unlikely. Instead, gradual increases in total energy demand are probable in the years ahead, mostly as a result of population growth. Nevertheless, according to the US Energy Information Administration (EIA), total energy consumption in the US is not likely to regain the 2007 peak again until 2020.

Kevin Logan
Chief Economist, US
HSBC Securities (USA) Inc.
+212 525 3195
kevin.r.logan@us.hsbc.com

Primary energy production and consumption in quadrillion BTU, projections post 2012



Source: EIA

Meanwhile, after years of stagnation, energy output in the US is undergoing a renaissance thanks to the production of oil and natural gas from shale and other “tight” geological formations that were previously inaccessible. As production from these new resources increases, the need for imported sources of energy should continue to decrease (see chart below). The EIA is projecting further substantial gains in US crude oil production, to 7.4mbd this year and then up to 8.4mbd by 2016.

Oil imports to fall to 10% of energy consumption

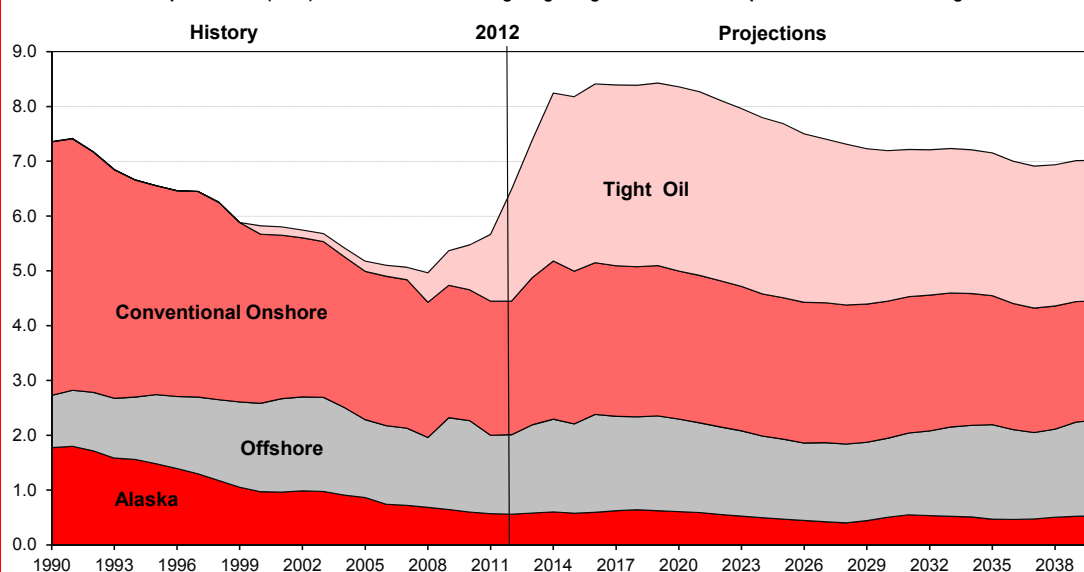
Following the 2008 recession, the share of imported energy products in total consumption declined rapidly as new domestic sources of oil and gas production came on stream. In 2009, at the end of the recession, the import share was 24%. By 2012, the displacement of imports by domestic production took the import share of total US energy consumption down to 17%. Projected increases in US oil and gas production should push the import share down further to 10% in the next 15 years, according to the EIA.

The drop in energy imports is partly the result of a decline in the energy “intensity” of the US economy. Energy use per capita has dropped about 10% since 2005. Though much of that decline is related to the recent recession and high unemployment, high prices for oil products have also driven down energy usage.

US oil boom a short one

Since 2008, high crude oil prices have made expensive production techniques such as horizontal drilling and hydraulic fracturing in

Total US crude oil production (mbd): Oil from shale and “tight” geological formations expected to increase through 2016



Source: EIA

shale and other “tight” formations worthwhile. However, the current surge in US crude oil production is expected to be relatively short-lived, lasting roughly 10 years, from 2007 to 2017 (see chart on previous page). After that, the exploitation of new shale oil deposits is expected to just replace the depletion of previously developed deposits.

Natural gas boom to last longer: US to export

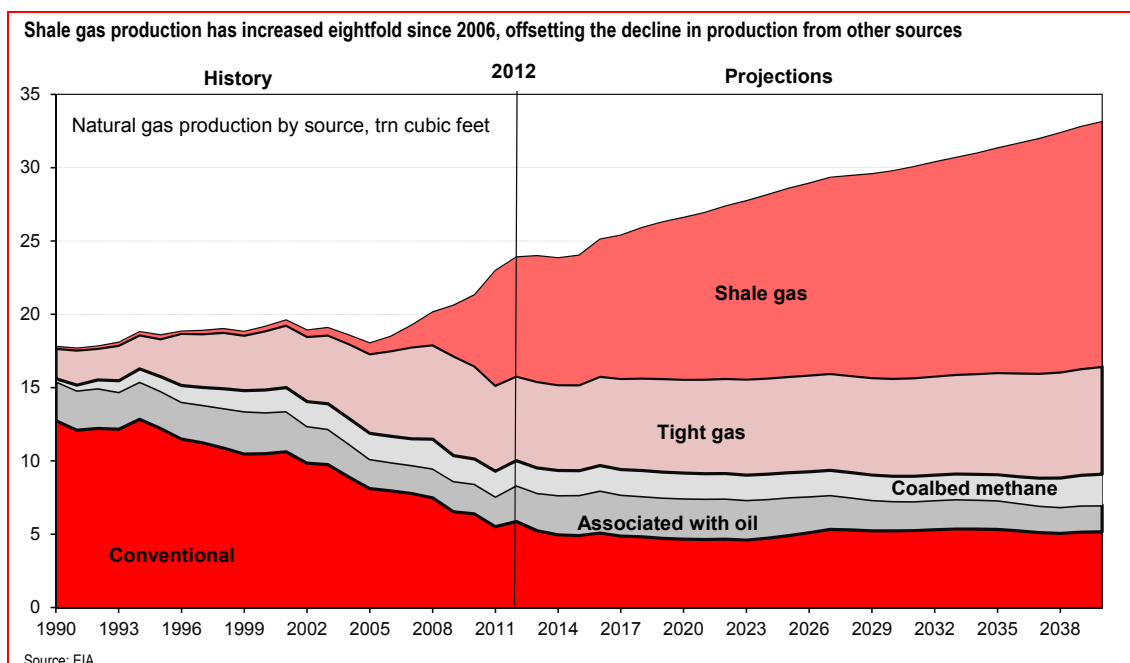
In contrast, the ongoing bonanza in shale gas production is expected to last much longer. The anticipated increase in natural gas production is expected to far outstrip the growth in domestic demand for gas. If production does increase as anticipated, the US is likely to transition from a net importer of natural gas to a net exporter by the end of this decade. Domestically, natural gas will gradually substitute for other fuels, though this transition will take some time.

The increase in natural gas production over the past few years has come exclusively from the exploitation of shale gas deposits extracted through newly developed horizontal drilling and

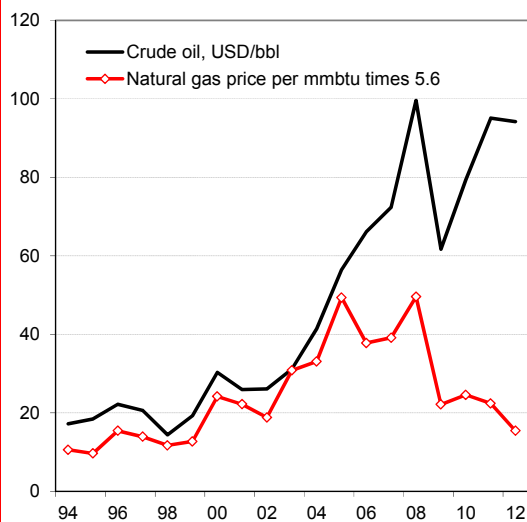
hydraulic fracturing techniques. Natural gas production from other sources has declined steadily since the early years of the last decade.

The surge in shale gas production makes it appear that a technological breakthrough suddenly occurred around 2005, but that is not actually the case. The development of horizontal drilling and hydraulic fracturing techniques took decades to develop. According to the EIA, the practical application of horizontal drilling to oil production began in the early 1980s, with the gradual emergence of improved drilling motors and the invention of other necessary supporting equipment, materials, and telemetry technology.

The surge in the availability of natural gas has set off a wave of rebalancing within the US energy sector. The price of natural gas has fallen and has become much cheaper compared to alternative energy resources. Natural gas is commonly priced per million British thermal units (mmBtu). A barrel of crude oil has an energy content of 5.6mmBtu. To the degree that natural gas and oil are substitutes for energy use, a barrel of crude oil should sell for roughly 5.6 times the spot price for



Crude oil and natural gas prices on an energy equivalent basis



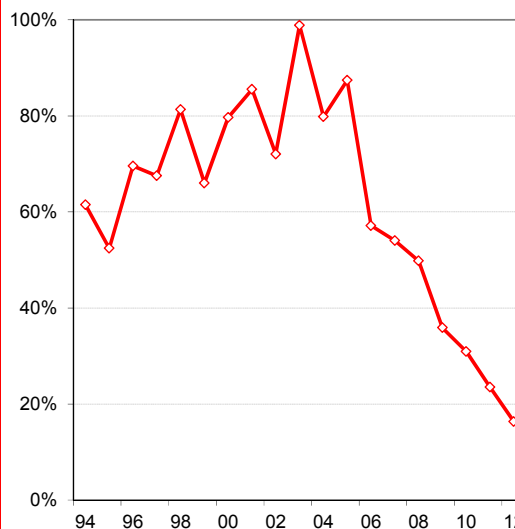
Source: EIA, West Texas benchmark for crude oil, Henry Hub spot price for natural gas

natural gas. That was the case in the US up until 2006 when the energy-equivalent price of the two fuels began to diverge significantly (see chart above left). The divergence in price is strong support for the view that crude oil and natural gas are limited substitutes for each other given current uses for each fuel.

The low relative price of natural gas has led to an increase in demand for gas where gas can easily be substituted for other fuels. We look more closely at the potential for substitution of gas for oil in the global transportation sector in a later section, with the biggest switches to gas expected for commercial, not private-use, vehicles.

In the US, gas has begun to displace coal in the generation of electricity. This in turn has led US coal producers to export more of their production, particularly to Europe. Gas will also displace nuclear power generation since cheap natural gas will keep down the price of electricity. Nuclear power plants that were due for renovation are being shuttered instead because the capital costs of renovation cannot be recovered if electricity prices remain low due to the availability of abundant natural gas. The same is true for new nuclear power plants.

The energy-equivalent price of natural gas in the US has fallen to about 20% of the price of crude oil



Source: EIA, West Texas benchmark for crude oil, Henry Hub spot price for natural gas

Natural gas imports and exports

Currently, the US is both an importer and an exporter of natural gas. The bulk of imports comes from western Canada and is sent via pipeline into the US Midwest. From the Midwest and Eastern states, US exporters send natural gas to eastern Canada via pipelines. Gas is also exported by pipeline from Texas into Mexico.

US international trade in piped natural gas and LNG

Billions of cubic feet (bcf)	2010	2011	% change
Canadian exports to the US	3261	3106	-5%
US exports to Canada	738	939	27%
US exports to Mexico	331	497	50%
Net pipeline imports	2192	1670	-24%
Net LNG imports	374	282	-25%

Source: BP

In the face of the surge in the production of shale gas in the US, imports have been falling off while exports have increased rapidly. Net imports via pipeline fell 24% from 2010 to 2011 (the latest year for which the data are available). Net imports of liquefied natural gas (LNG) are down 25%, and will probably continue to fall since the average domestic price for natural gas in the US is too low

to justify shipping LNG to the US rather than to other international markets.

Mexico is a clear winner from the US shale gas boom. Increasing supplies of low cost natural gas are already flowing across the border. Since natural gas is used mostly for electricity generation, the availability of US natural gas should keep electricity costs low, benefiting both consumers and manufacturers in Mexico.

For Canada, the situation is mixed. Consumers of natural gas, especially in the eastern Canadian provinces, benefit from the lower cost of fuel, but the producers of natural gas in the western Canadian provinces have to grapple with low prices for their output. Since they face the prospect of continued low prices for natural gas in their main market in the US, Canadian gas producers are investing in the development of LNG export facilities, similar to those now being developed in the US (see chapter on Canada). The bulk of this LNG development will take place in British Columbia, with exports aimed at the Asian market. By reducing US demand for imports of natural gas from Canada, the US shale gas boom will indirectly lead to increased supplies of natural gas for consumers in Asian markets.

Investments planned for LNG export facilities

The US currently lacks the liquefaction facilities for the conversion of dry natural gas to LNG which would enable gas to be exported in bulk. That will change within the next few years as LNG export facilities are built in the US.

The estimated cost of liquefying and transporting LNG can add about USD4.00-6.00mmBtu to the US spot price of natural gas (see “Shale: The oil and gas view” for more details). The spot price of natural gas in the US this year has averaged about USD3.70mmBtu. Since the landed price of LNG fetches about USD10mmBtu in Europe and about

USD15mmBtu in Asia, there is ample incentive for potential gas exporters to invest in the liquefaction and transport facilities that will take domestic US natural gas into global markets.

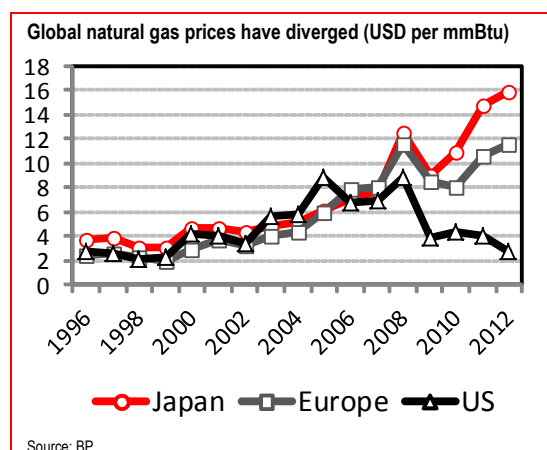
The Department of Energy (DoE) has now approved four applications for the development of LNG export terminals. One is on the Gulf Coast in Texas. Two others are in Louisiana. The latest approval was for a facility in Maryland on the Mid-Atlantic Coast. These export facilities will be developed by international energy consortia and the gas will be exported to customers in Europe and Asia where natural gas demand continues to grow and where the consuming countries are interested in diversifying sources of supply. The first LNG export facility to be approved (at Sabine Pass in Louisiana) has contracts to export gas to the UK, Spain, South Korea, and India.

The four export facilities that have been approved have a planned combined export capacity of roughly 2.4trn cubic feet per year. It will take several years to build the approved export facilities, and it will not be until the end of this decade that exports are likely to reach the approved capacity. When these facilities come on stream, their export capacity will equal about 10% of US natural gas production projected for 2020.

The DoE has another 18 applications pending for the development of natural gas export facilities. Not all of these are likely to be approved. The DoE has wide latitude in deciding whether to approve gas export facilities. The Department can deny applications that it decides “will not be consistent with the public interest.”

Given the current glut of natural gas in the US market, the development of export facilities is consistent with contributing to overall economic growth in the US and to the profitability of the natural gas industry itself. At the moment, US gas prices are lower than those in Europe and Japan

(see chart below). However, as new export facilities are developed, the domestic price of natural gas may start to rise, provoking opposition from domestic users of gas. At that point, fewer applications for export facilities are likely to be approved.



Concerns that gas exports may increase prices

Many producers of natural gas favor an expansion of exports while some large consumers of natural gas, such as the electricity generation industry, argue that it might be beneficial to protect the US economy from supply and demand pressures in international markets. Some worry that increased exports could drive up the price of natural gas domestically, which in turn would raise energy costs for households, businesses, and the manufacturing sector.

Some US manufacturers that utilize natural gas as a fuel or feedstock have expressed concern that an export-driven increase in the price of natural gas would adversely affect their ability to compete in the global market for products such as fertilizers, petrochemicals, steel, and other goods that have high energy content in the manufacturing process.

Because of this concern over the potential price impact of allowing LNG exports, a number of economic studies have been conducted by various government agencies and consulting groups. Most of the studies suggest that the impact of LNG exports on domestic prices would be small.

The Department of Energy sponsored an extensive study by NERA Economic Consulting in 2012 that examined the macroeconomic impacts of LNG exports. The study concluded that allowing LNG exports would have only a small influence on domestic prices because foreign buyers would not purchase LNG from US exporters if wellhead prices were to rise above the cost of competing supplies.

One benchmark study compiled by analysts at the Brookings Institution in Washington reviewed a number of research studies on the potential impact of LNG exports on US natural gas prices. Most of the estimates for price increases fell into a narrow range of 2% to 11% compared with a baseline scenario that included no LNG exports.

The domestic price impact of LNG exports could be self-limiting. There are high costs for the liquefaction and transportation of LNG. The raw cost of natural gas would have to remain relatively low for US LNG producers to profitably process and transport LNG to markets in Europe and Asia and recoup the cost of their investments. Increasing US exports to foreign markets would eventually put some downward pressure on prices in those markets as well.

In addition, US exports will also be competing in Asian markets with large-scale Australian and Canadian LNG exports that are likely to come on stream in the coming years (see chapters on Australia and Canada). In sum, even as the US turns from being a net importer to a net exporter of natural gas, the domestic price of natural gas in the US is still likely to remain well below the level in most other countries around the world.

Energy boom affects GDP...modestly

The dramatic changes in domestic energy production and trade have had only small effects on GDP growth for the past few years. Future effects are likely to be small as well. We estimate that, over the next five years, increased domestic energy production would add 0.1-0.2% to the annual growth rate of GDP.

Thirty years ago, oil and gas extraction were an important part of GDP, accounting for about 4% of total economic output. That share has fallen to about 1.5% in recent years as the energy intensity of GDP has declined. Rapid growth in a small sector of the economy is not going to lift overall GDP growth very much. Here are some key data:

- ▶ US GDP growth has averaged only 2.1% since the end of the recession in 2009 despite the surge in oil and gas production.
- ▶ In 2010, the latest year for which the complete data are available, total expenditures on energy products in the US amounted to about 8.3% of GDP.
- ▶ Domestically produced energy products accounted for about 78% of that total, or about 6.5% of GDP.
- ▶ Net imports of energy products were equal to roughly 1.8% of GDP.
- ▶ If the current trends in the production of shale oil and gas continue along the lines expected by the DoE, the share of the US energy market supplied domestically should increase to about 88% in 2020 from 78% in 2012.
- ▶ The share of energy supplied by domestic producers would rise to 7.3% of GDP in 2020 from 6.5% in 2012, or about 0.8 percentage points.

Economic growth could get a boost in other ways than just through the increase in energy output itself. Certain industries may benefit from lower energy costs and therefore be able to produce more at the margin. Here again, though, the effects are likely to be small. The transportation sector relies primarily on oil as a source of fuel and oil prices are set in international markets. Consequently, US consumers are not likely to see transportation costs fall very much, if at all, as a result of cheap natural gas. Moreover, the demand for transportation services is not going to grow much faster than household incomes, and so there is little reason to believe that the growth of the transportation industry will increase materially because of lower energy costs.

Industries that benefit: Non-transportation industries

For non-transportation industries, energy costs average about 2.2% of the value of gross output. Natural gas makes up about 40% of the energy inputs into the industrial sector. As the chart on the next page shows, gas is more heavily used for industrial purposes than petroleum products.

The average price of natural gas has fallen about 60%, thanks to the abundance of shale gas. For the “average” industry, that means the cost of production will be about 0.5% lower than it would have been otherwise. Those savings could be absorbed into profit margins, or passed on to consumers through lower prices for final goods. Either way, the effect does not seem large enough to produce a big increase in output.

Averages can be deceiving, however. Some industries are intense users of energy, others are not. For example, energy costs are close to 6% of gross output costs in the primary metals and paper products industries.

Chemicals industry: High energy costs and beneficiary of lower gas prices

The chemical industry has above-average energy costs and also uses petroleum and natural gas as feedstock for the production of chemicals. Cheap natural gas would doubly benefit US chemical producers compared to producers in other countries without access to cheap gas.

Chemical products happen to be the largest single category of US exports, accounting for 16.2% of all manufactured exports in 2012. Exports of metals, plastics, and paper and wood products accounted for another 14.5%, bringing the total for these combined categories to about 31% of US exports of manufactured goods.

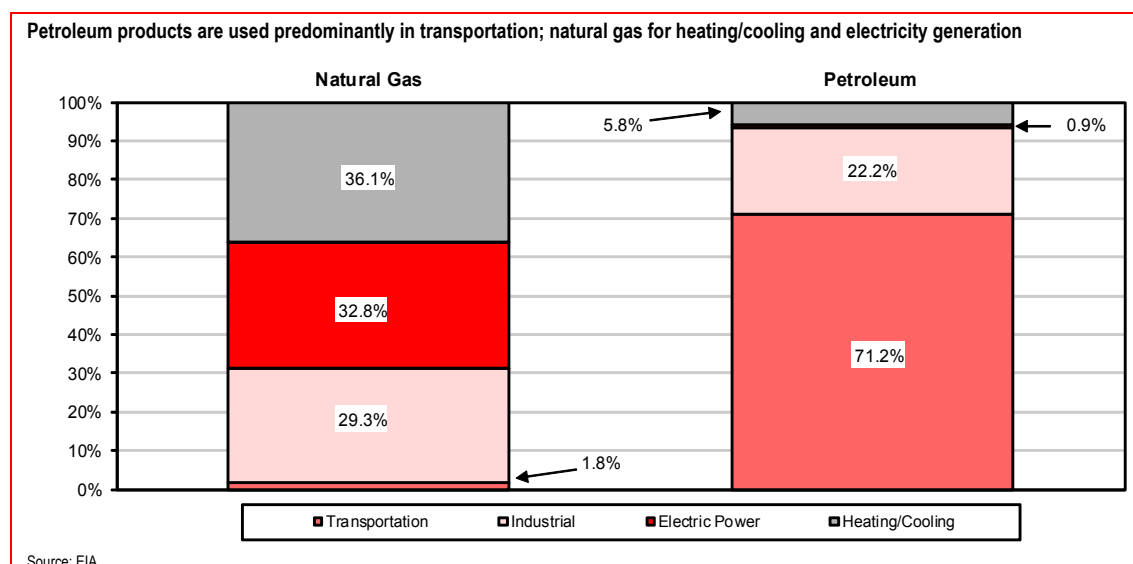
These industries have the potential to gain more market share, both domestically, by replacing imports, and internationally, by taking market share away from producers in other countries.

In the past two years, at least half a dozen major companies have announced plans to build new plants for the production of chemicals and plastics in the US based on the availability of low-cost shale gas. And a major steel company has announced plans for new processing facilities that will take advantage of long-term agreements for the supply of low-cost natural gas.

Industry impact on growth

How big an impact could an accelerated rate of growth in these industries have on the growth rate of US GDP? These three industries – chemicals, plastics, metals, wood and paper products – accounted for roughly 34% of value added in US manufacturing in 2011. In the previous 20 years, combined output in these industries grew at a 3.4% annual rate. If that growth rate were to double in the coming years as producers in these industries took advantage of low cost natural gas, thereby increasing exports and displacing imports, they would produce about USD20bn more in value added in the first year and increasingly more in subsequent years.

As mentioned earlier, we estimate that increased energy production will add 0.1-0.2% to GDP annually over the next five years. On top of that, growth in industries like chemicals, which can benefit from cheaper gas, could add a further 0.1% per year to GDP growth over the next five years.



IMF study of energy and US growth

Researchers at the International Monetary Fund (IMF) tried to get a handle on these general equilibrium effects in their recent report on the US economy (IMF Country Report 13/237, July 2013). Using the IMF's Global Economy Model, the researchers investigated the impact of a decline in average energy costs on the growth of the US economy. In their analysis, they included direct output effects, trade effects, and changes in household spending.

Their model simulations suggest that the macroeconomic effects of lower energy costs for the US are positive, but modest. Over a 10-year period, the level of GDP should increase 0.5-1.0%. The overall effects appear modest mainly because of the small share of the oil and gas industry and other energy-intensive industries in the economy. A real appreciation of the dollar is another factor holding down the overall growth impact.

Labor costs not affected by energy prices, limiting export impact

In sum, it appears that macro implications for US GDP growth from the availability of cheap natural gas are limited. Most of the positive effect on manufacturing output derived from lower costs and increased competitiveness would come from a decline in the trade deficit on manufactured goods. However, access to cheap natural gas would have little effect on trade for the majority of US imports. Nearly 70% of US manufactured imports are products for which labor costs are the dominant consideration rather than the cost of energy inputs.

The trade balance could improve for certain industries, such as chemicals, plastics, metals, and paper products, where energy costs are a significant consideration. Reasonable estimates for the change in the trade balance or for the acceleration in growth in these industries suggest that the overall impact on GDP would be modest, probably in the neighborhood of 0.2-0.3% per annum over the next five years.

Shale: The oil and gas view

- ▶ Shale gas is plentiful, shale oil less so; both face a number of challenges including costs, logistics, and environmental issues
- ▶ We see the US shale revolution being followed by a somewhat slower evolution elsewhere in the world
- ▶ Obstacles to shale growth outside the US include limited experienced crews, water, land use, noise, and political concerns

Why has shale burst on the scene?

The simple answer is technology. Shale oil and gas deposits are found in relatively thin, horizontal reservoirs. Conventional vertical wells only access a small cross-section of the reservoir. The reservoirs are also 'tight,' meaning they do not flow even when a well penetrates the reservoir. Improvements in horizontal drilling techniques in the last decade meant that wells could be guided more accurately into the reservoir, accessing a much greater surface area of producible hydrocarbons.

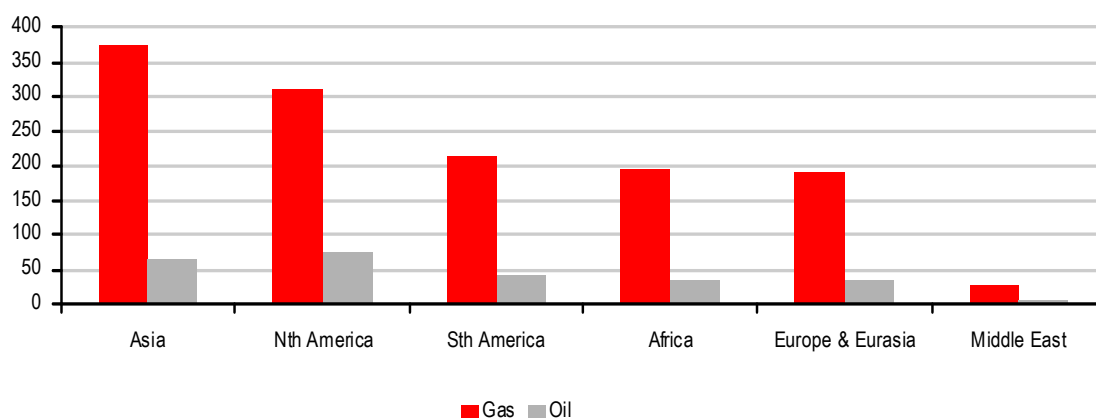
By itself, this would not have been sufficient to lead to a shale revolution. Improved seismic technology meant that drillers could 'see' the potential reservoirs more clearly – better sub-surface imaging, to be technical. More importantly, advances in fracturing techniques meant that channels could be opened up within the reservoir, enabling hydrocarbons to flow to the well bore and to the surface. Without this technique, the hydrocarbons would remain in the reservoir, even if a successful horizontal well was drilled.

David Phillips*
Co-head of Oil & Gas Research
HSBC Bank plc UK
+44 20 7991 2344
david1.phillips@hsbcib.com

Thomas Hilboldt*
Head of Asian Oil & Gas and Petrochemicals Research
The Hongkong and Shanghai Banking Corporation Limited
+852 2822 2922
thomaschilboldt@hsbc.com.hk

*Employed by a non-US affiliate of HSBC Securities (USA) Inc, and is not registered/ qualified pursuant to FINRA regulations

Potential resource (tight oil and gas): Billion barrels of oil equivalent

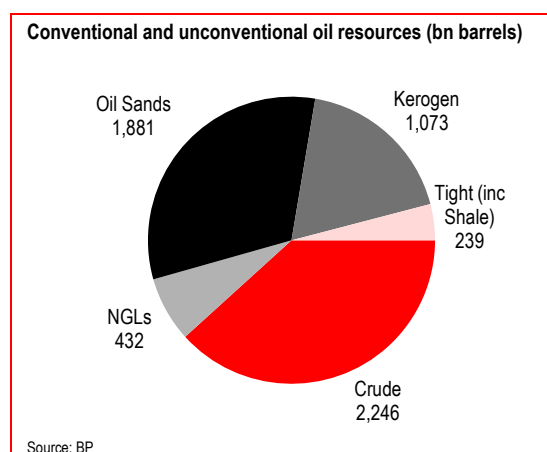


Source: BP

How big is tight oil and gas?

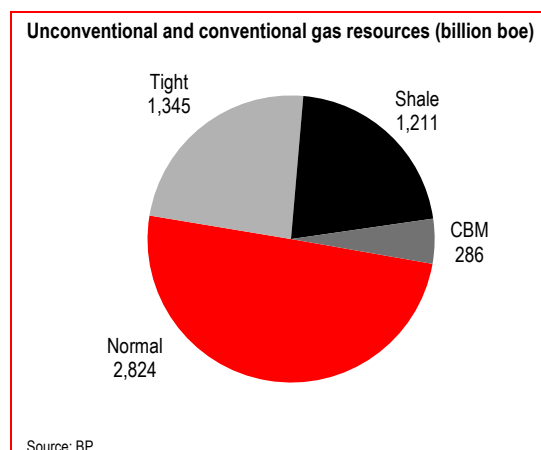
The answer to this question is not straightforward. Many of the estimates for unconventional resources, including shale, are estimates of the amount of oil and gas in place. This does not take into account how much of this can be produced to surface, a proportion which can be as low as 5% of that in place. Other estimates are for the potential or prospective resources. These estimates cover basins where few, if any, wells have been drilled and there is often little or no evidence that the reservoirs contain oil and gas. Other estimates take no account of whether the oil and gas is commercial and are therefore purely theoretical estimates of resources.

As a result, estimates for the potential for unconventional resources of oil and gas can vary markedly. For oil, both the International Energy Agency (IEA) and BP carry a number of around 250 billion barrels (bn bbl), around 30% of which are in North America. This compares to the EIA's estimate for kerogen of 1 trillion barrels (trn bbl) and for oil sands of 1.9trn bbl. The EIA also sees around 345bn bbl of shale oil as technically recoverable.



So, tight oil, including shale, is a relatively small resource base when compared to existing conventional reserves and other unconvensionals.

Tight gas (including shale) is rather more material relative to the overall resource base. It makes up 45% of the total, similar to the 50% made up by conventional or normal gas.



BP's estimate for unconventional gas resources is 1.3trn bbl of oil equivalent. The IEA's is materially higher at 2trn bbl, mainly due to higher estimates for tight gas. The IEA's estimates for shale and coal bed methane (CBM) are similar to BP's.

It is important to note that not all of these resources are necessarily commercially viable, even at oil prices over USD100 per barrel. For example, the near 1trn bbl of kerogen (or oil shale) in BP's numbers are not commercial at present. They do, however, represent around 30 years of current global oil demand, suggesting the world is still some way from peak oil – assuming the economics improve.

US shale revolution

Given that tight oil, including shale oil, is a relatively small part of the world resource base, the interest it has generated might seem surprising. But, having seen the impact shale gas had on the US market and the recovery in US oil production, it is fair to describe it as a shale revolution – at least in terms of production.

In 2000, shale gas accounted for virtually none of the US's gas production, and the accepted wisdom

was that the US would need material amounts of imported gas, either from Canada or in the form of liquefied natural gas (LNG). There were many major investments in LNG import (regas) terminals in the US; most of these are now either poorly utilized or are awaiting planned/possible conversion into LNG liquefaction plants to support LNG exports.

Shale gas presently accounts for around a third of production, and the US Department of Energy (DoE) estimates that it could reach half by 2040. It could mean that the US becomes a net exporter of gas by 2020. (Source: US Energy Information Administration, Annual Energy Outlook 2013.)

Although the shale oil resource base in the US is relatively small, it too has seen a sharp rise in production as new drilling and fracturing techniques have been utilized. But whereas – with hindsight – the shale gas revolution began in 2005, the oil revolution began at the tail end of the last decade. US tight oil production was around 200-300,000b/d between 2000-2008, reached 500,000b/d in 2010, and recently reached just over 2m b/d, a five-year compound growth rate of around 45% (compare this to overall US oil production of around 10m b/d and overall North American production of around 14m b/d). Recent updates from the IEA see tight oil production rising to just under 2.6m b/d by H2 2013; North Dakota alone could see 900,000b/d by the end of 2013.

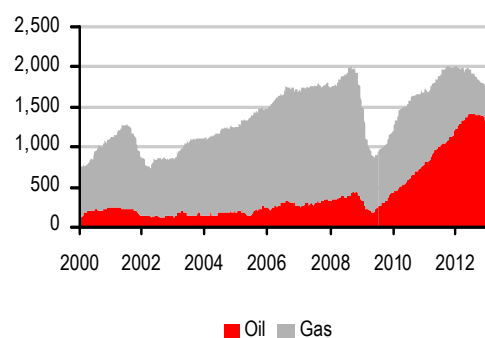
However, the US shale oil revolution owes much to several US-specific issues:

- ▶ The US has the world's largest and most advanced land drilling fleet, together with an experienced fracturing industry (including expertise in reservoir analysis/seismic, abundant pressure pumping capacity, fracturing equipment, and fluids/proppants).

- ▶ It has a well-developed gathering and transport infrastructure, for both oil and gas.
- ▶ Its shale plays have been remarkably stable over geological time, meaning the reservoirs are relatively predictable (unlike in Europe and China). Many of the reservoirs are at a depth that optimizes well economics (unlike in Europe and China).
- ▶ US taxation of oil and gas production is relatively benign and it has an active, liquid spot market.
- ▶ Landowners have title to oil and gas produced on their land and can share the economic benefit through royalty payments.

There is a further factor that helped the US shale oil revolution – the end of the shale gas revolution. The industry's success in boosting domestic gas production meant that gas prices fell from around USD6-8mmBtu in 2005-2008 (reaching as high as USD14) to a low of USD2 in 2012. With shale gas wells needing a price of USD3-5mmBtu to be economic, there was a precipitous fall in the number of rigs drilling for gas (and the associated equipment and services – particularly the more commoditized services like pressure pumping, where capacity had grown rapidly through the first phase of shale gas growth).

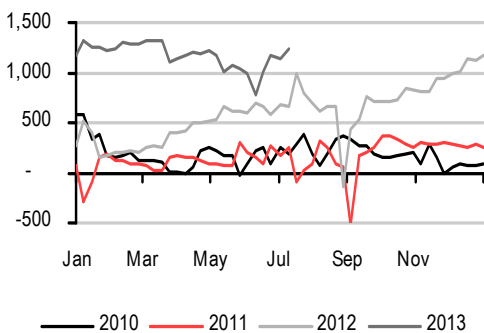
US rig count split by gas and oil



Source: Baker Hughes

The number of rigs drilling for gas dropped from 1,500 in late 2008 to under 400. In contrast, the number of rigs drilling for oil rose from around 400 at end 2008 to 1,400 recently. It is perhaps not surprising that a sevenfold increase in the number of rigs chasing oil should lead to a marked supply response.

US production of crude oil (million b/d)



Source: EIA (US DoE)

With the level of rigs drilling for oil now stabilizing, we would expect the rate of growth in production of US shale oil to start to slow. We believe that the rate of growth may already have stabilized. (The chart above shows total US production and also reflects a recovery in production from the US Gulf of Mexico following Macondo-related delays to developments.)

There also have been some signs that certain shale prospects have not proved as good as expected

and have not produced as much liquids content as expected, hence weaker potential economics.

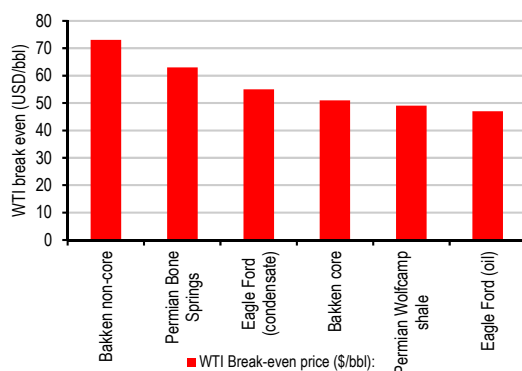
Shale isn't cheap

The economics of shale resource development and production are often glossed over in political viewpoints that are keen to highlight the potential resource (and all it might bring for energy self-sufficiency for the region in question).

But the simple matter is that shale gas and oil are not necessarily low cost, which is one of the reasons why they have not been exploited before. Shale oil is, vs other oil resources, relatively higher cost than shale gas is vs conventional gas. There is, of course, a wide range of field economics, but we see the USD50-80/bbl range as being a good indication of the oil prices needed to support shale oil production. This puts the upper price end of shale oil at around the levels needed to support the more costly ultra-deepwater projects (breakeven investment hurdles for deepwater are in the USD50-90/bbl range).

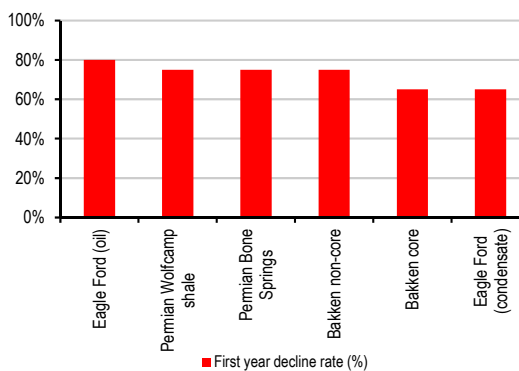
One other important difference is the relative size of the projects – one shale well (as part of a larger development) could cost a few million US dollars, whereas one major deepwater project could cost USD10bn. Hence, shale developments are much more modular and can be scaled back (temporarily) if needed, a feature that could prove

Typical WTI break-even prices for key shale plays



Source: S&P

Typical first year production decline rates



Source: S&P

attractive to international oil companies (IOCs) that might have a more cautious outlook for new E&P investment.

With gas, our view on shale production costs in the US is around USD3-5/mmBtu (some third parties see a higher upper end – the IEA sees production costs up to USD7/mmBtu). This compares to conventional gas resource costs that are in a similar range for the US, higher for Europe and China, and lower for Russia and the Middle East (where costs are more in the USD1-2/mmBtu or below range). These shale gas costs are also likely to be higher in China and Europe, the other regions that have seen shale gas-related activity, based on the initial assessment of reservoir quality and recovery rates.

Also, looking at the LNG export angle for the US gas market, at current gas prices – post liquefaction and transport – shale gas costs equate to a landed cost into Asia of around USD11-12/mmBtu (and less into Europe or LatAm, at around USD10/mmBtu). This compares to imported LNG prices into Asia in the USD15-18/mmBtu range or higher (and for reference, USD10/mmBtu is equivalent to USD60/bbl). Clearly, gas costs of USD6/mmBtu or more could reduce this potential spread to less attractive levels. Also, these LNG projects are competing with the next waves of LNG production planned for East Africa, Australia, and elsewhere.

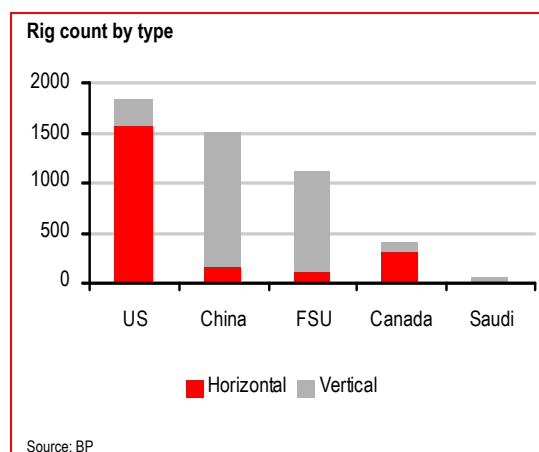
Can the US shale revolution spread?

The simple answer to this question is “yes.” Producing shale reservoirs have already been found in Latin America and Asia. As discussed earlier, the potential for shale gas resources is materially higher than that for oil.

To date, the pace of appraisal of shale resources (and unconventional resources in general) outside the US has been far slower than that in the US.

But this is hardly surprising. Drilling of shale and CBM reservoirs is only really economic using horizontal wells. Although some vertical CBM wells have been drilled in China, their productivity has been low – as has profitability, we suspect.

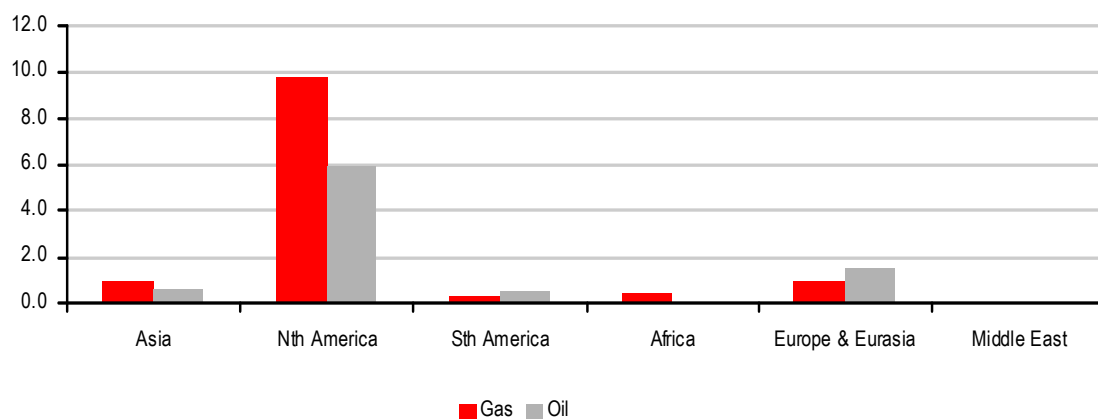
Outside the US and Canada, the land rig fleet is either small in numbers (Europe) or has little capability (and experience) of drilling horizontal wells (China and Russia). The number of experienced fracking crews is also limited outside the US and Canada.



Even if the major North American oil services companies continue to expand their shale expertise globally, we believe that the scarcity of complex rigs and experienced fracturing crews will make the pace of development of tight oil and gas far slower than has been the case in the US. Lack of gas-gathering infrastructure will also be a hindrance in some countries, as might lack of access to water for fracturing. This could be particularly important in Argentina and China.

Another factor that may slow down the pace of exploitation is land usage and noise. A typical development pad takes up around 10-15 acres and fracturing a well involves several hundred journeys by heavy trucks to bring in – and subsequently remove – fracturing fluids. In areas of low population density, such as much of the

Potential production of tight (shale) oil and gas by region in 2030 (million boe/d)



Source: BP

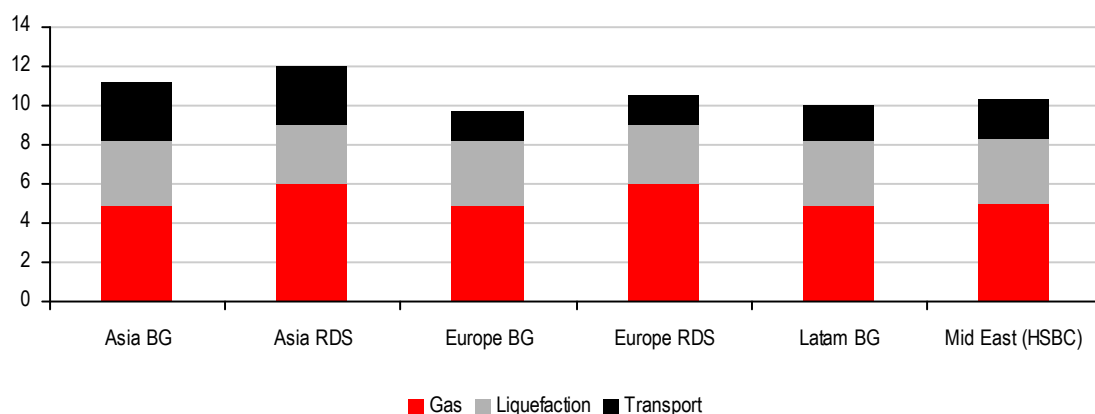
Midwest US, these factors are not a material issue. In areas of high population density, such as China and Western Europe, they are likely to be more of an issue.

Other environmental issues include concerns that aquifers could be contaminated with fracturing fluid or even natural gas (as shown in the anti-fracking film called “Gaslands”). With proper completion of wells, neither of these should be an issue, but thanks to some earlier well-publicized problems in the US (largely due to smaller companies cutting corners with well casing designs and failing to control “fracking fluid”

leaks), the image is in the media and is now a fairly common public view (see for instance the protests against potential fracking in the UK).

Geology is also conspiring against the exploitation of shale gas (the “geology vs technology” theme). In Europe, the reservoirs are deeper and more variable than in the US, thereby increasing extraction costs. Also, the deeper reservoirs have often failed to flow even after fracturing. This appears to be the reason for the current disillusionment with shale gas in Poland. Results from the limited number of shale wells drilled in China are best described as mixed, in

Landed LNG prices from the US East Coast (in USD/mmBtu) – views from BG and Shell



Source: BG, Shell, HSBC

our view (although CBM appears to be making more progress). We would also note China's shale oil resources (as seen so far) tend to be waxy, implying less efficient recovery.

There also is the ever-present issue of politics, particularly outside the US –limiting/controlling the access to resources by international oil companies, structuring the taxation and economics of production, and so on. As an example, we would note recent developments in India, where it is likely that the country will take several more months to draw up a framework for shale exploration (for both local and international E&P operators).

Views on shale from the EIA

We note some of the changing views on shale resources as published by the EIA in June of this year. The original EIA study from 2011 is one of the most quoted studies on shale resources around the world (focused very much on gas), and the update covers more countries, more hydrocarbon basins, and adjusts assumptions for recent well results and geologic research.

The June 2013 study concluded that the technically recoverable resources of shale gas were 7,299tcf (roughly equivalent to 1,300-1,400bn boe – barrels of oil equivalent) and for shale oil/tight oil were 345bn barrels (note technically recoverable is not the same as – and is less than – economic recoverable resources).

The estimate for shale gas put the figure 10% higher than that in the 2011 report, but there were also several reductions in certain countries:

- ▶ Norway's Alum shale – this dropped from 83tcf to zero after some drilling updates.
- ▶ Poland's Lubin Basin – the projected shale gas resource was reduced from 44tcf to 9tcf due to technical issues.

- ▶ Mexico's Eagle Ford shale in the Burgos Basin – the shale gas estimate was reduced from 454tcf to 343tcf.
- ▶ South Africa's Karoo Basin – for the country as a whole, the shale gas estimate was reduced from 485tcf to 390tcf.
- ▶ China's Qiongzhusi shale in the Sichuan Basin gas – estimate was reduced from 349tcf to 125tcf, and the Lower Cambrian shale in the Tarim Basin – estimate was reduced from 359tcf to 44tcf. Both reductions reflect better information regarding the organic content and geologic complexity.

Evolution outside the US, revolution in the US

Altogether, the many factors highlighted in this report help explain why, in our view, the shale revolution outside the US (or, more correctly, North America) is likely to be a much slower process.

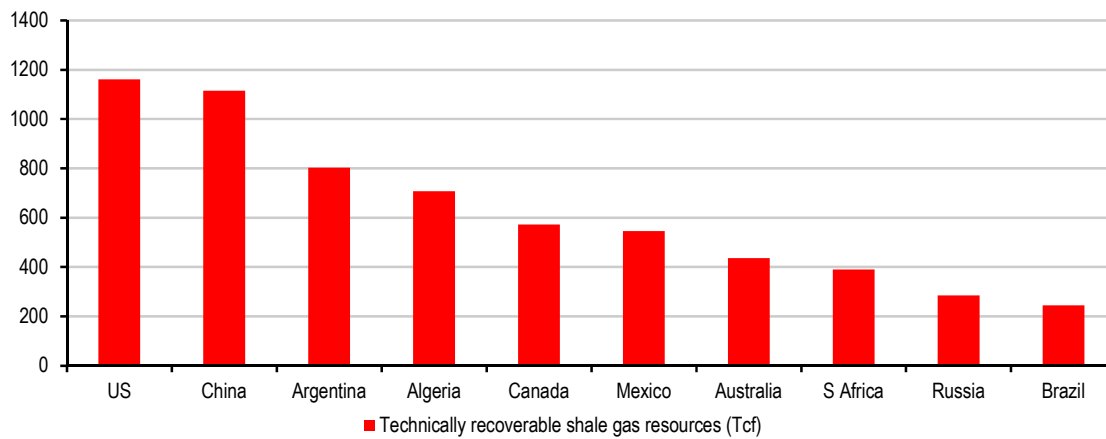
This conclusion is similar to that reached by BP. By 2030, North America (predominantly the US) is expected to still be the only material producer of natural gas and oil from tight reservoirs.

For oil, BP expects that production of tight oil (mainly shale) in 2030 will amount to a little under 9m b/d, or 9% of total world production. North America will account for nearly 70% of tight production of oil.

For gas, BP sees production of tight gas (including CBM) rising to a little over 12m b/d (in oil equivalent terms). This is around 16% of total world gas production, but nearly 80% of this production of tight gas is from North America.

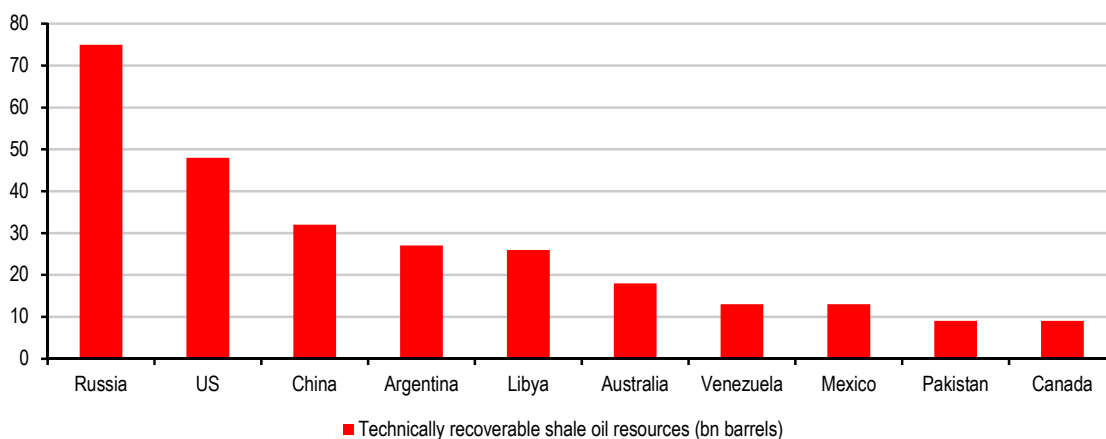
So, after the (ongoing) shale revolution in the US, we think it is more realistic to expect a shale evolution elsewhere in the world.

Technically recoverable shale gas resources (measured in tcf) – main countries listed (total estimated resources: 7,299tcf)



Source: EIA (June 2013), tcf = trillion cubic feet

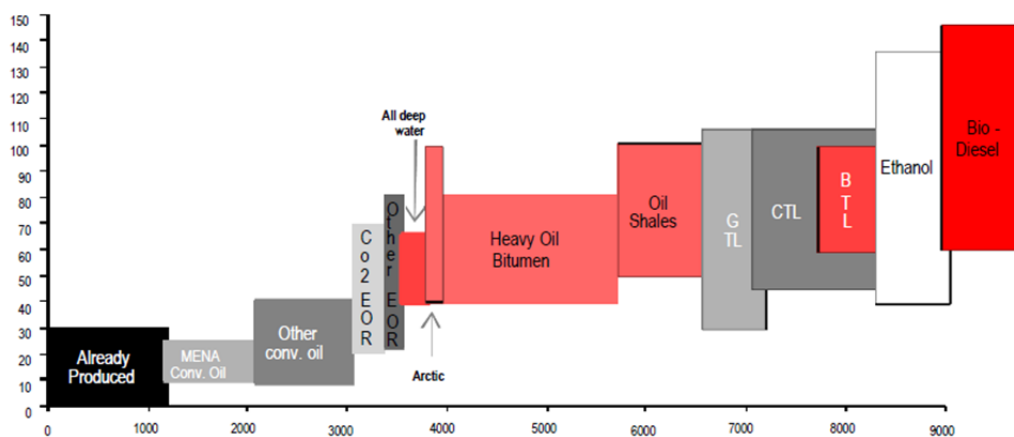
Technically recoverable shale oil resources (in bn bbl) – main countries listed (total estimated resources: 345bn bbl)



Source: EIA (June 2013)

Indicative full cycle break-even investment hurdles vs cumulative resource

X-Axis: Oil reserves (bn b), Y-Axis: Oil price breakeven (USD/b)



Source: IEA

Gas and oil substitution

- ▶ We expect LNG-powered transport to develop more rapidly for commercial transport like taxis and trucks than for private use
- ▶ Significant efforts are underway to increase the commercial gas-powered fleet in North America and China
- ▶ Gas is becoming more widely used as a fuel in shipping and new emissions laws may help encourage the use of gas

The potential for gas to replace oil in transport

An important issue for the market in shale gas is the potential for gas to replace oil as a fuel. The market has already seen gas replace coal to a substantial degree in the US in power generation. Now, there is discussion about the potential for gas to replace oil products as a fuel.

There is a temptation to see liquefied natural gas (LNG)-powered transport as having a potentially rapid and major disruptive impact on oil product demand. There is support for using more gas from environmental viewpoints (lower emissions) and as part of improving overall 'industrial competitiveness,' but the challenge is the economics/cost of conversion and/or newly build vehicles, in addition to the investment needed in LNG refueling infrastructure.

The LNG-fueled transport theme is more likely, in our view, to develop in commercial transport rather than for private use. In effect, this would be gas replacing diesel rather than gas replacing gasoline. The actual design of LNG-fueled engines uses LNG/gas as the primary fuel but also has a small amount of diesel to ignite the gas in the engine

combustion process, so vehicles typically run with two types of fuel tanks – one small diesel tank plus one or two large LNG tanks.

In a high-oil price/low-gas price environment, the effective spread between diesel and gas means the payback on vehicle conversions to LNG fuel could be quite attractive. But visibility on this gas/diesel spread (or more specifically on this LNG/diesel spread, given that at current US prices converting natural gas to LNG roughly doubles its price) is a key consideration. Weaker payback on investment could dissuade many potential commercial users of LNG-powered vehicles. In addition, applications that make use of long range journeys (high fuel consumption per vehicle) are likely to be better suited to making the most of this LNG vs diesel price spread.

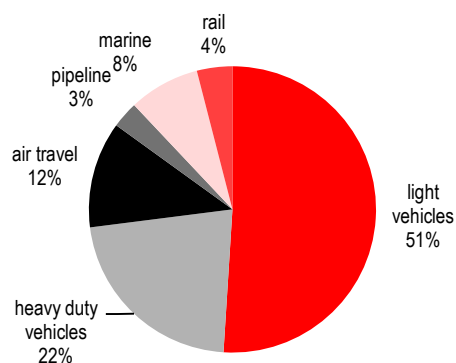
We therefore expect this theme to be less likely to apply to consumer markets, due to the likely tougher economic choice between what would probably be the less flexible (in terms of destination, given the reliance on a re-fueling network) and higher cost of gas-powered vehicles vs hybrids and the more efficient turbo-charged petrol powered cars, as well as modern diesels.

David Phillips*
Co-head of Oil & Gas
Research
HSBC Bank plc
+44 20 7991 2344
david1.phillips@hsbcib.com

Thomas Hilboldt*
Head of Asian Oil & Gas and
Petrochemicals Research
The Hongkong and Shanghai
Banking Corporation Limited
+852 2822 2922
thomaschilboldt@hsbc.com.hk

*Employed by a non-US affiliate of HSBC Securities (USA) Inc, and is not registered/ qualified pursuant to FINRA regulations

US energy usage in transportation (2012)



Source: EIA Annual Energy Outlook 2012

Commercial vehicles use gas

We would note several significant efforts already underway to increase the gas-fueled commercial vehicle fleet in North America and also in China (specifically, this is more LNG-based than CNG – compressed natural gas).

China. Government sources (e.g. China's Ministry of Housing and Urban-Rural Development) see around 30bcm of gas potentially used in transportation by 2015, which would be about 13% of the National Development and Reform Commission's latest estimate of 230bcm gas demand in 2015. The ministry also stated that there was 6bcm of gas used in transportation in 2010, equivalent to about 6% of the total gas demand in that year.

Also, on a longer-term view, China National Petroleum Corporation (CNPC) sees around 7m natural gas powered vehicles by 2020, using 42bcm of gas. There are already several companies looking to develop the LNG vehicle market and its infrastructure, such as Kunlun Energy, ENN, Xinjiang Guanghui Energy, CNOOC, and China Gas Holdings. LNG vehicles are moving up the priority ladder in terms of government policy, but as yet are not classified as "new energy vehicles," so still lose out on some subsidy support.

North America. There are numerous schemes moving ahead on the industrial transport side and also with gas infrastructure (e.g. Clean Energy Fuels, which aims to build "America's Natural Gas Highway"). Most heavy/medium duty truck manufacturers in the US offer a gas-fueled option, although the uptake of new models has so far been relatively gradual. US engine makers such as Cummins have noted that the infrastructure challenge is not too daunting, with only a need for a certain number of LNG stations along main interstate highways (fewer LNG stations are needed vs oil-based fuels), but the spread of gas-fueled vehicles across the heavy road transport fleet would likely be gradual.

Chinese fuel comparisons – economics and general info between LNG, CNG, gasoline, diesel with applications on taxi, buses, and trucks

	Taxi			Bus			Truck		
	Gasoline	CNG	LNG	Diesel	CNG	LNG	Diesel	CNG	LNG
Economics									
Price (Rmb)	7.5/L	4.0/m3	4.5/m3	7.0/L	4.0/m3	4.5/m3	7.0/L	4.0/m3	4.5/m3
% discount to gasoline or diesel (calorific basis)	-	(52%)	(46%)	-	(38%)	(31%)	-	(38%)	(31%)
Average distance / day (km)	300	300	300	200	200	200	400	400	400
Fuel consumption rate (litre/100km or m3/100km)	10	9	9	30	32	32	40	43	43
Daily consumption (litre or m3)	30	27	27	60	65	65	160	173	173
Daily fuel expense (RMB)	225	107	121	420	259	292	1,120	691	778
Daily saving (RMB)	-	118	104	-	161	128	-	429	342
Conversion fee / Price differential (RMB)	-	10,000	10,000	-	50,000	50,000	-	80,000	80,000
Payback period (month)		2.8	3.2		10	13		6	8
Generals									
Tank pressure	normal	high	normal	normal	high	normal	normal	high	normal
Tank temperature	normal	normal	low	normal	normal	low	normal	normal	low
Winter travel capability	Moderate	Bad	Good	Moderate	Bad	Good	Moderate	Bad	Good
Safety	Moderate	Bad	Good	Moderate	Bad	Good	Moderate	Bad	Good
Environmental impact	Bad	Good	Good	Bad	Good	Good	Bad	Good	Good
Key bottleneck	Price	Station#	Station#	Price	Station#	Station#	Price	Station#	Station#

Source: Zhangjiagang Furui Special Equipment, Asia NGV communication, local media, HSBC

There are also various alliances between companies such as Shell and TravelCenters of America, and Encana and Heckmann, that target a build-out of LNG refueling infrastructure. UPS is also looking to have the most extensive private fleet of LNG vehicles by the end of 2014 (it has over 100 LNG vehicles at present and aims to purchase 700, as well as building several new fueling stations). UPS indicated that its vehicles see 30-40% lower prices (vs petroleum fuel), 25% lower CO₂ emissions, and a 600-mile range.

Gas as a marine fuel

There is also the usage of gas as a fuel for the shipping and offshore industry. There are roughly 30-40 LNG vessels in operation, mostly ferries in the Scandinavian countries and/or the Baltic, plus some supply vessels in the North Sea. The order book for LNG vessels (majority are dry bulk carriers or cruise ships) will roughly double this number over the next couple of years.

But this use of gas as a fuel faces many of the same infrastructure challenges as other forms of transportation, such as the need for a LNG-capable marine bunkering network – as well as the cost of converting existing vessels. It is estimated to cost roughly USD40-50m to convert a large containership engine and fuel system, or around USD10m to convert a car/passenger ferry. Building new LNG-powered vessels is typically 15-20% more expensive than non-LNG-powered vessels. For a variety of reasons, we expect it will likely prove an easier economic decision to invest in a new vessel than convert an old one.

For converted vessels, there can be a 15-20% power loss (for dual fuel designs that use a small amount of diesel alongside the gas). In addition, there is a loss of cargo space below deck to fit in the LNG tanks and fuel system.

There is also a different cost dynamic – with the cost of liquefaction roughly doubling the cost of the gas in liquefied form, LNG can be more expensive than the usual mix of fuel oils and distillate. But LNG is cheaper than low-sulphur blends, which are set to become increasingly a firm requirement for the shipping industry, with major restrictions on fuel sulphur limits coming in 2015 (in North America/Caribbean) and with the International Maritime Organization (particularly for vessels that spend a lot of time in coastal waters). This emissions driver may well be the key trigger to wider adoption of gas as a fuel offshore.

A Lloyd's Register survey on these emission laws saw the use of low sulphur fuel as a near-term solution, the use of exhaust gas scrubbers (exhaust clean-up) as a medium-term solution, and LNG fuel as the longer-term solution (on a 10-year horizon). A DNV (Det Norske Veritas) report expects 10-15% of new ships to be gas-fueled between now and 2020 (assuming a favorable spread remains between LNG and fuel oil prices).

Environmental concerns

- ▶ Emissions from shale will be increasingly scrutinized, especially those surrounding leakage of methane
- ▶ Water availability and the potential for groundwater contamination are already causing concern in some countries
- ▶ Land constraints and land conflicts are issues in China and India

Shale development spurs environmental debate

Environmental considerations may become more prevalent as more countries around the world consider shale as part of their energy strategies, in combination with delivering on climate policies which restrict or reduce carbon emissions.

There are three main issues surrounding shale:

(1) Emissions

- ▶ Is consumption of shale oil and gas aligned with fossil fuel emissions containment strategies?
- ▶ Will concerns on methane leakage emissions from shale gas become greater?

(2) Water

- ▶ Is there enough resource for hydraulic fracturing?
- ▶ Are groundwater contamination and other pollution risks increasing?

(3) Land

- ▶ Is land availability a constraint in populous countries?

Emissions

Carbon constraints. All fossil fuels, including shale oil and gas, contribute to greenhouse gas (GHG) emissions when consumed for energy (i.e. burned). First, many countries have in place carbon constraints, for example, in the form of emissions trading schemes or carbon taxes – with many of these schemes put in place to help countries meet their GHG reduction targets.

Second, on a global scale, most governments agree that policies are required to limit global warming to 2°C. This concept has evolved into an “unburnable carbon” idea wherein the atmosphere can only cope with a certain amount of carbon emissions, and, hence, the rest must be left in the ground.

To these points, the cost of developing shale oil and gas may become uneconomical in light of restrictions placed on fossil fuels as a result of carbon emissions control.

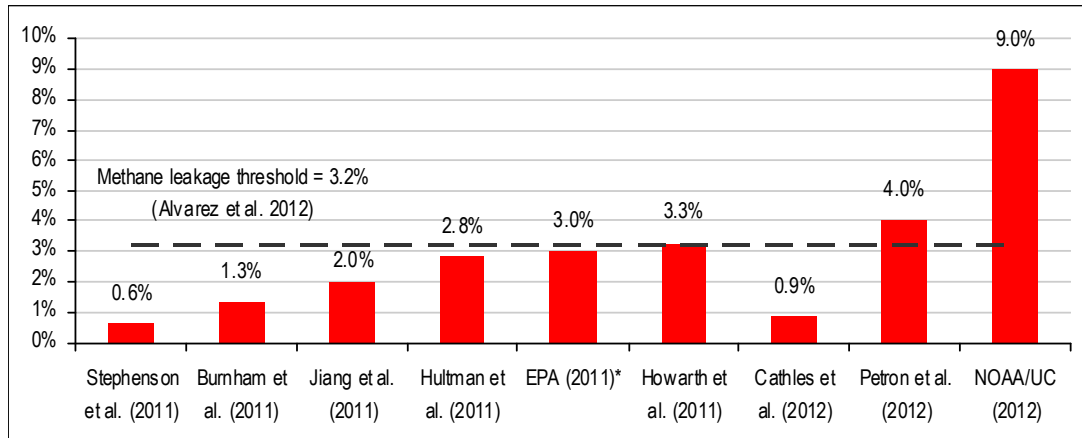
Leakage. Closely related to GHG constraints is the concept of preventing methane leakage (relating predominantly to shale gas). Regardless of whether there are national or even global caps on emissions, there is increasing scrutiny over the pollutant level of leakages from shale gas

Nick Robins
Head, Climate Change Centre
HSBC Bank plc
+44 20 7991 6778
nick.robins@hsbc.com

Zoe Knight
Climate Change Strategist
HSBC Bank plc
+44 20 7991 6715
zoe.knight@hsbcib.com

Wai-Shin Chan, CFA
Climate Change Strategist
The Hongkong and Shanghai
Banking Corporation Limited
+852 2822 4870
wai.shin.chan@hsbc.com.hk

Estimated methane leakage rates from shale gas production



Note: NOAA/UC (2012): Scientists team from NOAA and University of Colorado at Boulder at an American Geophysical Union (AGU) meeting in San Francisco, California, presented their preliminary results of a study conducted in Utah region of the US.

Source: Alvarez et al. Proceedings of National Academy of Sciences (USA 2012), Methane Emissions from Natural Gas Systems (2012). * The EPA (2011) estimate is as calculated in Howarth et al. (2012), using national emissions from EPA reports and national gas production data from US Department of Energy reports.

development. Gas leakages may escape into the atmosphere (global warming) or potentially into water (contamination).

In theory, shifting from coal to gas is beneficial from an emissions perspective as burning gas releases less carbon dioxide (CO₂). Indeed, countries such as China are trying to switch their energy mix to use less coal and more gas in an effort to manage their emissions. As a result, the IEA expects global gas consumption to increase by around 47% over the next 20 years – with half the increase coming from unconventional gas in China, the US, and Australia.

However, the benefits are quickly eroded when methane leakage from shale production is considered. Methane has a much higher global warming potential than CO₂ (see [Super pollutants in China and the US](#), 23 July 2013). There have been many scientific publications concerning methane leakage rates of natural gas production. A prominent study by Alvarez et al. put the threshold at which gas loses its ‘cleaner’ status at 3.2% leakage. Although measuring leakage is very difficult, estimates from various agencies and scientists range from as low as 1% to as high as 9%.

These concerns could lead to a tightening of regulations surrounding the casings used when drilling shale wells, resulting in extra investment needed for leakage prevention.

Water

Availability. Shale development is very water-intensive. The US Department of Energy (DOE) estimates that over the life of a single horizontal well, approximately 2.5-5m gallons of water are required for the hydraulic fracturing process.

Whether water availability will hamper the shale development process depends on the geographic location. In some areas where a supply of water via a lake or river is not easily accessible, water needs to be brought in via trucks and tankers – this is an expensive process but also adds to the emissions profile (on a life-cycle-analysis basis) of the shale produced. Also, there have been concerns that the necessary water could come from groundwater, thus depleting these essential resources.

In countries which are seeing water shortages and even water conflicts, we think growth of a water-intensive industry such as shale is likely to be challenging (see [Water stress: Analysing the global challenges](#), September 2012).

For example, China has ambitious shale production targets of 6.5bcm annually by 2015, rising tenfold by 2020 – all from a base of virtually zero in 2012. At the same time, the government has imposed water quotas at national and provincial levels as climate change alters historical patterns of water availability. Although the shale-rich southwest provinces are not technically water-stressed, certain shale fields are located far from water sources, and the surrounding areas have suffered severe droughts as recently as 2010.

There is increasing discussion in China that the 2015 target may not be met, for a variety of reasons, including water availability and the lack of infrastructure for wastewater treatment. We think the mismatch between China's shale and water ambitions could result in a slower-than-planned development of shale. Moreover, given the water intensity of shale gas production, it would add to the existing competition for water in China which includes agriculture, growing municipal use, and existing industries. We think any potential unrest because of this may be something the Chinese government wishes to avoid.

The Energy and Resources Institute (TERI) of India believes that a shale gas well could use between 2.8-13m gallons of water for fracturing and well preparation – this is more than the US DoE estimate. For India, these are significant volumes given the country is already water-stressed and is fast moving towards becoming water scarce (see [Water: Are you stressed yet?](#), 12 July 2012). Indeed, eight out of India's nine major shale basins are in water-stressed/scarcie regions (see [Hurdles to India's shale hopes](#), 22 July 2013).

Pollution. Water availability is dependent on both the quantity and quality of the water; hence, there is the thorny issue of potential groundwater

contamination – especially in China where groundwater supplies two-thirds of the population's drinking water.

In the US, there is strong public opposition to hydraulic fracturing in certain jurisdictions on the back of groundwater contamination concerns. For example, the state of Maryland is debating the harm to drinking water from fracturing, and the EPA of New York City has called for a ban because of the threat to the city's drinking water.

Water is used in many different parts of the shale production process, for example in chemical mixing, well injection, and flowback (when the water returns to the surface), and there is potential for spills at each stage. Also, despite increasing reuse of water by the industry, large volumes must still be appropriately treated afterwards since the water is laced with chemicals.

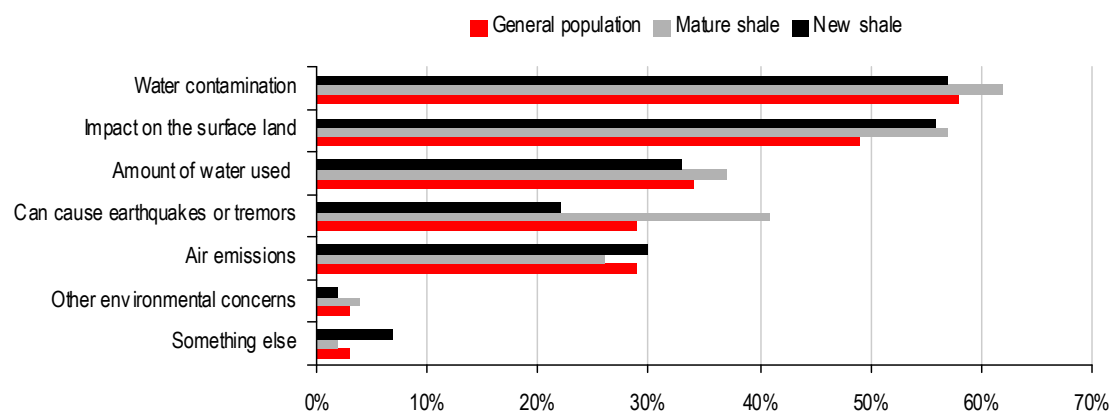
This wastewater treatment is not without its problems as large pools are required to hold the wastewater (while it is being treated), which brings the possibility of water leakage into the surrounding soil or ecosystems. Also, some countries do not have the appropriate regulations or infrastructure in place to cope with such large volumes of wastewater, which raises the possibility of accidental spills.

Land

Conventional gas fields can hold a relatively high plateau production rate (85% or more of peak) for long periods; in contrast, unconventional gas wells experience sharp production decline rates of 70% or higher after reaching peak production within a few months. This means that the economic exploitation of shale gas reserves requires the continuous drilling of wells which entails hundreds of square kilometers of land area.

Land acquisitions or securing permits for shale drilling is more difficult in certain countries. In the US, land availability is less of an issue and

Awareness about possible effects of shale gas development in the US



Note: Sample is 1694 online interviews in the US (General population= 663, Mature shale= 537, New shale= 494)
Source: Deloitte Survey: Public opinions on shale gas development, 2012

many thousands of shale wells have already been drilled, covering a large area of land. However, China and India have lower land availability per capita than the US. In addition, China and India are already seeing increasing conflicts over land, especially as the potential for pollution could unsettle local populations.

The debate continues

The shale debate is likely to continue as more studies are published on the environmental and social issues surrounding shale. These studies, as well as public opinion, affect policy decisions. Countries such as the UK, Poland, Canada, and China are keen to develop shale, while others such as Bulgaria and France have banned fracturing. As recently as July, the top court in France wanted to review the ban but this idea was promptly overruled by President Hollande.

Within the US, Pennsylvania passed legislation last year allowing shale drilling across the entire state; however, Maryland has put applications for shale well drilling on hold for three years pending an environmental impact study; New York has a moratorium in place due to public health effects; and Vermont voted to ban the practice outright in 2012.

In China especially, we believe environmental and water laws will tighten as the 'Beautiful China' policy is pursued – a change from historically weak enforcement. As a result, we think concerns over water availability and contamination are only going to grow in China, and also in India.

In conclusion, the environmental and social concerns surrounding shale oil and gas development are not easily alleviated and are likely to remain subject to intense debate as shale penetrates more and more jurisdictions around the world.

This page has been left intentionally blank

Geographies

Argentina
Australia
Brazil
Canada
China
Mexico
Middle East
Poland
Russia
UK
Venezuela

Argentina

- ▶ Historically, Argentina has relied on its own gas and oil resources
- ▶ The country was a net energy exporter until 2010; the shift to the role of importer has had significant negative macro implications
- ▶ Vast shale resources hold out the promise of self-sufficiency but will require years of exploration and development

From feast to famine

Argentina's energy sector has recently evolved into one where supply-demand imbalances are met by increasingly expensive imports. This is having significant economic repercussions.

Tapping into its unconventional shale resource potential is key to helping alleviate the issue, but will take years and require substantial investment.

The public sector had a large presence in the energy sector until the late 1980s. In the 1990s, many firms, including the main oil company, YPF, were privatized. However, in the current decade the state's role in the sector has increased again, with the nationalization of some companies and broader intervention in the market.

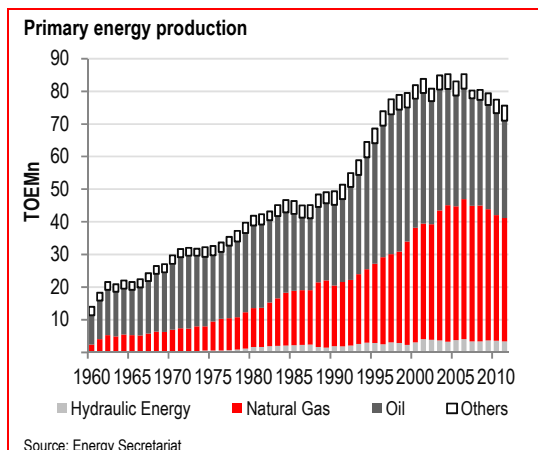
The country's main energy supply has been natural gas. Consequently, this has been Argentina's main source of heating energy, and the use of compressed natural gas in vehicles is widespread.

Peak oil and gas production was reached in around 2003. A decline followed during the 2000s, and production plateaued in 2010.

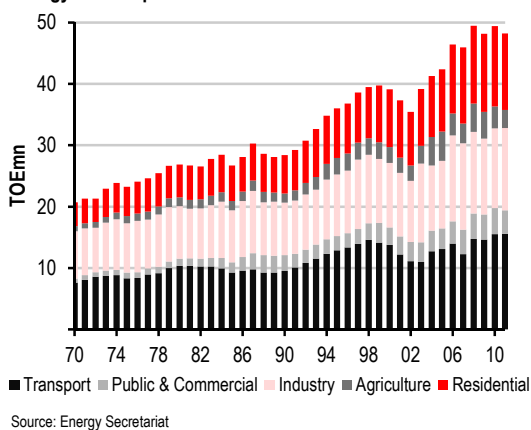
Demand-side policies have boosted residential energy consumption. Energy tariffs were frozen for years after the 2001 crisis in an effort to curb inflation, and energy price controls have continued to be used to depress living costs. As a result, Argentina's consumers pay much less for energy than others in the region.

GDP growth averaged 7.2% a year between 2003 and 2012. This, combined with cheap energy prices, caused energy consumption in Argentina to grow notably. On a per capita basis, electricity consumption rose 4.0% a year from 2000 to 2011. For households with access to electricity, average consumption increased 3.5% annually. In both cases, consumption is between 45% and 50% above levels in most of the region.

Jorge Morgenstern
Economist
HSBC Argentina S.A.
+54 11 4130 9229
jorge.morgenstern@hsbc.com.ar



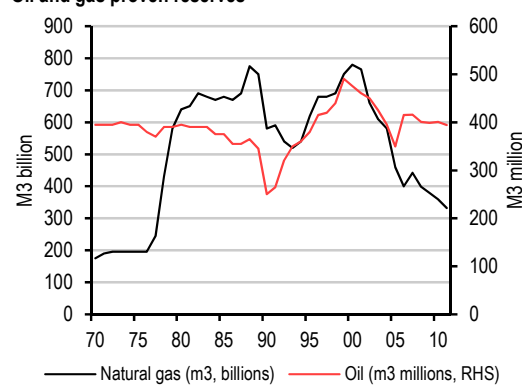
Energy consumption



On the supply side, the regulated prices paid to producers are well below marginal costs. This has been the flip-side of maintaining low consumer tariffs. As a result, domestic electricity, gas, and oil prices have become delinked from international prices.

Domestic investment in the energy sector has fallen in the past decade, explaining the decline in the country's energy reserves.

Oil and gas proven reserves



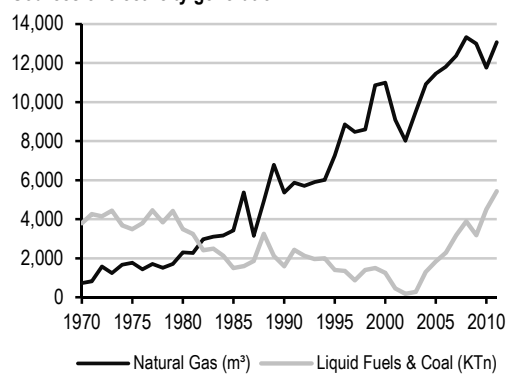
Energy demand started to overtake supply during the 2000s, reversing the country's position as a net exporter. Oil exports started to decline from 2003. Natural gas imports from Bolivia began in 2004 and at the same time gas exports to Chile were temporarily cut, as the country was facing shortages during the winter.

Gas exports ceased from 2007 onwards. Further shortages have since resulted in selective cuts of gas supply to industry to prioritize supplies to residential and then vehicle users. In 2008, the country began importing liquefied gas, which was regasified and injected into the distribution network.

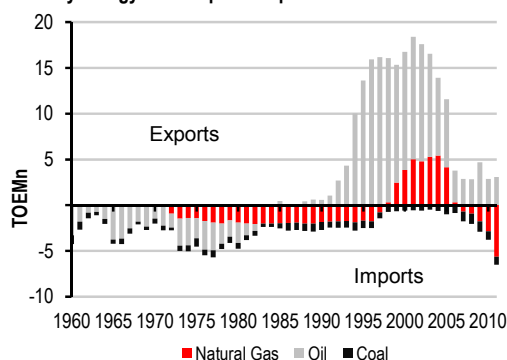
Energy supply costs have therefore risen significantly.

The restricted availability of natural gas led to the use of more expensive hydrocarbons for generating electricity. Also, imported natural gas was dearer than local production. By 2012, gas from Bolivia cost an average of USD11 per mmBtu vs USD18 per mmBtu for imported liquefied gas shipments. This compares to an average price paid to local producers of USD2.80 per mmBtu.

Sources of electricity generation

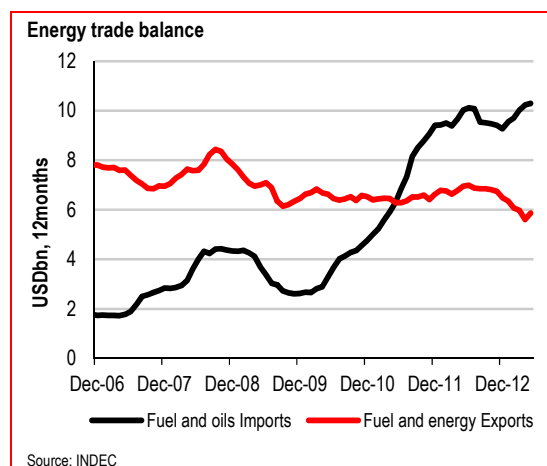


Primary energy – net exports-imports

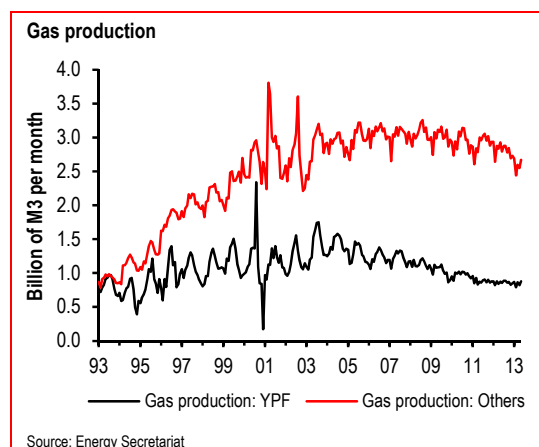


The sector imbalances have also translated into significant fiscal costs. The rising bill for imported energy, particularly gas – as domestic consumers were buffered against the price impact – was financed by the national government. Energy-related subsidies amounted to 2.5% of GDP by 2012 and although there was an attempt to gradually reduce subsidies in late 2011, they have since remained stable in terms of GDP. Importantly, most of these costs related to imports and required hard currency.

Energy imports are now a relevant macro issue. The USD6bn energy trade surplus of 2006 narrowed to USD3bn in 2010 and turned into a USD3bn deficit in 2011. The situation has continued to deteriorate and we expect the deficit to exceed USD5bn in 2013. This reversal was an important factor behind the deterioration in general foreign exchange flows that occurred in 2011, leading to broad-based restrictions on currency flows.



Partly in response to the sector's deterioration, the government nationalized Argentina's main oil company, YPF, expropriating a 51% share stake that belonged to Repsol. The government's justification for the nationalization was that the previous owners were not making the necessary investments. This, in turn, was linked to the decline in production and exploration. YPF's policy of high dividends and low profit reinvestment was also cited as a factor. At the



time, the company was the country's largest dividend payer and, as previously mentioned, the restriction of currency outflows was high on the government's agenda. Also, in November 2011, YPF had announced its estimates for reserves at the country's largest unconventional hydrocarbon resources field, Vaca Muerta.

Unconventional promises

Vaca Muerta is an oilfield in the Southern Province of Neuquen. It extends across 30,000sq km (YPF has concessions for over 12,000sq km in that area), has a depth of 200 meters, and is considered among the largest in the world.

Vaca Muerta field resources

	Oil Condensed (kkbl)	Gas (Mbe)	Total (Mbe)
Reserves	81	35	116
Contingent resources	1,115	410	1,525
Prospective resources	5,732	396	15,038
			21,166

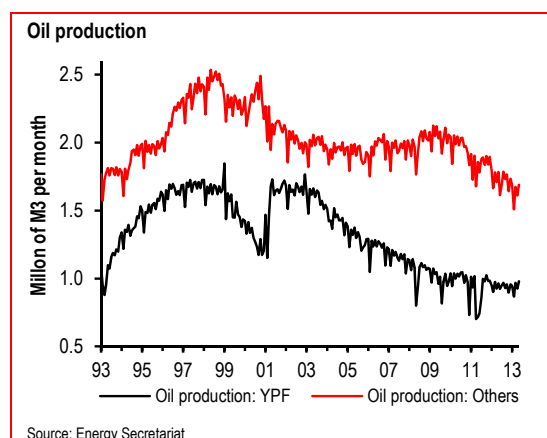
Source: YPF, Ryder Scott

According to the US Energy Information Administration, the country has 27bn bbl of unproven shale oil technically recoverable resources (TRR) – a large share of which corresponds to Vaca Muerta – compared with 2.805bn bbl of current proven oil reserves. The field also has massive gas production potential: 802trn cu ft of unproved shale TRR compared with 12trn cu ft of proved natural gas.

YPF estimated that a USD25bn annual investment effort over 10 years could double Argentina's oil and gas production.

Shale solution still years away

Following the nationalization of YPF, the government authorized increases in prices paid to energy producers, including YPF, and raised the reference price above which oil producers pay export duties. It also promised gas producers that a higher price would be paid on marginal increases in production. So far, however, production has shown no signs of recovery following the policy changes made since late 2011.



The use of unconventional resources should be a game changer, but it is currently hindered by the significant amount of capital needed to unleash its potential, combined with prevailing regulatory uncertainty. YPF's nationalization is, understandably, a factor of concern that companies must consider before sinking capital into the sector.

The government has introduced fiscal benefits for companies willing to make large investments in the sector. These include partial exemptions from trade duties, priority access to the currency market and a price guarantee related to international prices if domestic supply is prioritized. Chevron, which has signed an agreement with YPF on a joint venture to exploit Vaca Muerta, is set to be the first beneficiary. While the incentives for those willing to invest are clearer now, we believe it will take some time for the investment flow to ramp up. Consequently, alternative shale resources are still some years away from solving the energy bottlenecks affecting the economy as a whole and the currency market in particular.

Australia

- ▶ Liquefied natural gas projects account for the bulk of Australia's recent resources investment boom, with seven major projects worth almost USD200bn being built in Australia
- ▶ This new capacity is being built to produce exports for Asia and the bulk of the LNG is already forward-sold on long-term contracts
- ▶ Australia is expected to see a rise of around 400% in its LNG exports between 2010 and 2020 and is set to potentially overtake Qatar as the largest exporter of LNG in the world

Australia's gas

Australia ranks tenth globally in terms of proven reserves of natural gas and has the most reserves of any Asia-Pacific nation, ranking ahead of China. Overall, Australia's proven reserves account for around 2% of total global reserves. Given Australia's small population, its gas reserves significantly outweigh the expected domestic demand for energy such that Australia is a large exporter of gas.

The bulk of Australia's proven reserves are from conventional sources. However, estimates of the economic demonstrated resource (EDR) of unconventional gas have also risen strongly in recent years. Coal seam gas now accounts for around a quarter of Australia's total gas EDR, having risen from a marginal share in the early 2000s, due to improved extraction and detection technology.

Recent Energy Information Administration (EIA) estimates also highlight the future potential for shale gas in Australia. Overall, Australia ranks

seventh in terms of technically recoverable shale gas resources in a global ranking.

Current production

Australia's rise as a key exporter reflects technological innovation in the transport of LNG. Traditionally, international trade in gas has been dominated by pipeline transportation. Over the past two decades, LNG transportation costs have fallen by more than half. As a result, LNG's share of total gas trade has risen to around 30%, from around 20% in the early 2000s. Technological innovation has enabled Australia to deliver its isolated reserves to key international markets.

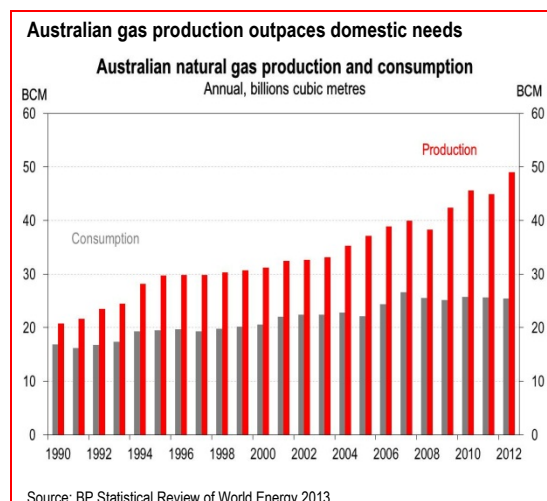
Australian gas production has increased steadily over the past 20 years, more than doubling over the period to around 49bn cubic meters a year. Australia is a major global producer of natural gas, accounting for around 1.5% of total global production.

Given Australia's small population, its gas production significantly outweighs its domestic consumption. Australia currently exports around

Paul Bloxham
Chief Economist,
Australia & New Zealand
HSBC Bank Australia Limited
+612 9255 2635
paulbloxham@hsbc.com.au

Adam Richardson
Economist
HSBC Bank Australia Limited
+612 9006 5848
adamrichardson@hsbc.com.au

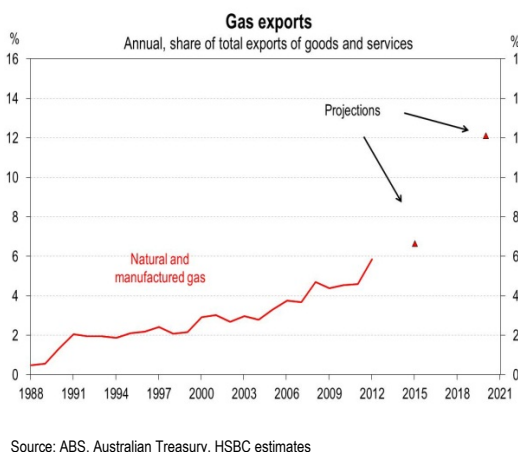
50% of its total production. As a result, Australia is a key player in international trade in LNG, currently being the world's third-largest exporter, behind Qatar and Malaysia. Australia accounts for 9% of the global trade in LNG.



Given market proximity, nearly all of Australia's LNG exports are to Asia-Pacific nations. Japan is Australia's key export market for LNG, and accounted for around 80% of Australia's exports of LNG in 2012. China is Australia's second-largest market, accounting for around 17% of exports, while South Korea takes around 4%.

As a share of total exports, gas exports are significant. At the end of 2012, gas exports accounted for around 6% of total goods and service exports from Australia – having grown significantly over the past two decades. We expect this strong growth to continue over the next decade – following the boost to production from Australia's resource investment boom.

Gas exports are a significant share of Australia's total



Recent investment boom

Australia has recently had a very large resources investment boom, a significant part of which has been investment in capacity to produce more LNG for the Asia-Pacific market.

Australia's large gas reserves, low population, and stable political and economic environment have encouraged a significant amount of foreign investment in Australia's LNG industry. Investment in the gas sector is currently being undertaken by a number of large multi-national corporations, including Chevron, ExxonMobil, Shell, and ConocoPhillips.

There are seven major LNG projects still under construction in Australia, with LNG, gas, and petroleum projects at the committed stage of planning totalling over AUD200bn. As a result of this investment, Australia is set to become an even larger player in global LNG markets. The first of these projects began construction in 2009 and the most recent got final approval for construction in 2012. The latter stages of Australia's recent resources investment boom have been driven by this strong rise in LNG investment.

Massive LNG projects still under construction

Project	Curr	Estimated spend
Gorgon	AUD	53.0
Ichthys	USD	33.0
Wheatstone	USD	29.0
Australia Pacific LNG	AUD	23.0
Queensland Curtis Island LNG	USD	20.4
Gladstone LNG	USD	18.5
Prelude	AUD	12.0

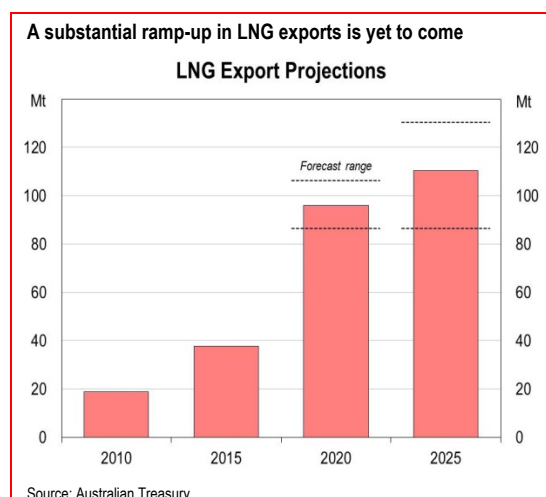
Source: Australian Treasury, BREE

From a global perspective, Australia's LNG investment stands out, with the massive projects that are currently underway constituting seven of the world's 12 largest projects currently under construction. Overall, current committed investment in Australian LNG production accounts for around two thirds of global investment in new capacity.

Export boom ahead

This investment will see a significant rise in Australia's exports of LNG when the projects come on line. Australian government projections suggest Australia could become the world's second-largest exporter by 2016, behind Qatar. If total projects under consideration were to be built, Australia would become the world's largest exporter of LNG by 2020.

Exports are expected to ramp up substantially in the next few years, with Australian government forecasts suggesting LNG exports will rise by around 400% between 2010 and 2020.



Contract prices apply

A much-discussed risk to the outlook for Australia's LNG exports and investment projections is the risk of a fall in gas prices – particularly given the potential for growth in global shale gas production and the possibility that the US could become a large exporter of shale gas.

Australia's industry should, however, be somewhat protected as the bulk of the gas that will come from the recent ramp-up in LNG production capacity has already been sold via long-term supply contracts.

This practice is particularly prevalent in the Asia-Pacific market, where 90% of LNG exports were under long-term contracts in 2010. These long-term supply contracts are generally linked to an underlying reference rate, usually crude oil prices, with a ceiling and floor on crude oil prices incorporated.

This practice brings some certainty to LNG projects, with supply contracts, generally around 15-20 years in duration, committed to during the initial investment phase. The large LNG projects currently under construction in Australia have announced a number of long-term purchase and supply agreements.

The high level of involvement in Australia's gas industry by global multinationals also reduces the risk to Australia of over exposure to one sector as a source of activity. The high external profit share of gas production limits Australia's potential upside, but also ensures Australia is not overleveraged to any downturn in the industry that could be brought on by competing suppliers.

Investment costs rising

Another related challenge for Australia's gas sector is the relatively high cost of capital expenditure on new projects.

Recent projects in Australia have capital costs ranging between AUD3-4bn per million tonnes of annual capacity – which are the highest in the world. In the past year this has discouraged commitments to new investment in additional projects beyond the ones that are currently under construction.

There are, however, signs that cost pressures are beginning to ease as the investment cycle in Australia's LNG industry matures, which is taking some pressure off labor and capital costs.

Australia's shale gas potential

As discussed, conventional gas makes up the majority of production and EDR in Australia, followed by coal seam gas. However, shale gas does have the potential to become a significant source of supply over the longer term. As a way of comparison, *unproved*, technically recoverable shale gas reserves are four times larger than *proved* natural gas reserves in Australia.

However, the eventual EDR of shale gas remains highly uncertain.

EIA estimates suggest Australia has the seventh-highest technically recoverable shale gas reserves in the world. However, shale gas exploration and development is still in early stages. According to the EIA, smaller independent companies have made initial assessments of high potential shale basins in Australia. Major international companies are now beginning to shift capital towards such projects.

One factor that is likely to slow the pace of development is a lack of gas infrastructure in some shale gas locations. While the Cooper Basin benefits from existing infrastructure, other key shale gas areas are remote and lack established infrastructure. In addition, extraction costs are expected to be high in Australia relative to other markets – with Australian developments expected to be more capital intensive in comparison.

The remote locations of these shale gas areas do have one major advantage in this regard. They are generally not close to populated areas – which could limit opposition to future development of the resource.

Brazil

- ▶ Brazil's new oil fields remain competitive; Brazilian shale gas reserves are more expensive
- ▶ Increased demand and delays in delivering new capacity have led to a larger deficit in the oil and derivatives trade balance
- ▶ Energy supply is not a permanent constraint on growth, but it does suggest the need for heavy short-term investment

The new energy order: Brazil oil story still holds

The main development in energy in Brazil over the last decade has been the discovery of big offshore reservoirs of oil in the deep offshore pre-salt cushion by the national oil company Petrobras. Drilling of these reservoirs started some years ago, and the investment needed by Petrobras and its private sector partners to fully develop the discovery's potential represents an important part of Brazil's investment effort during the current decade.

New oil fields remain competitive

The developments in shale oil and gas reducing the US's dependency on international sources of energy may have little effect on the Brazilian oil story.

According to Petrobras, the lifting costs associated with the wells in the pre-salt fields range from USD40-45 per barrel of crude. While the depth of the wells implies significant fixed costs, these are not high on a per-unit basis because of the sheer scale of the reservoirs. This places the cost of the Brazilian new offshore reserves at a competitive price level vs the

low-cost shale gas projects – such as those in the US. The chart overleaf presents a comparison of the break-even costs of new oil and gas projects across the world, by type of project.

As result, investments for the exploitation of the oil in the pre-salt reservoirs remain viable, and should lead to steady growth in oil production in the country over the next years – for more details see [Brazil Oil & Gas: Faith no more; initiating with a negative view](#), 21 June 2013.

The expected reduction of oil demand from the US as a result of increased local production should not impact Brazil, as Brazil is currently a net importer of oil, and the expected rise in production should not result in any exporting surplus until the end of the decade.

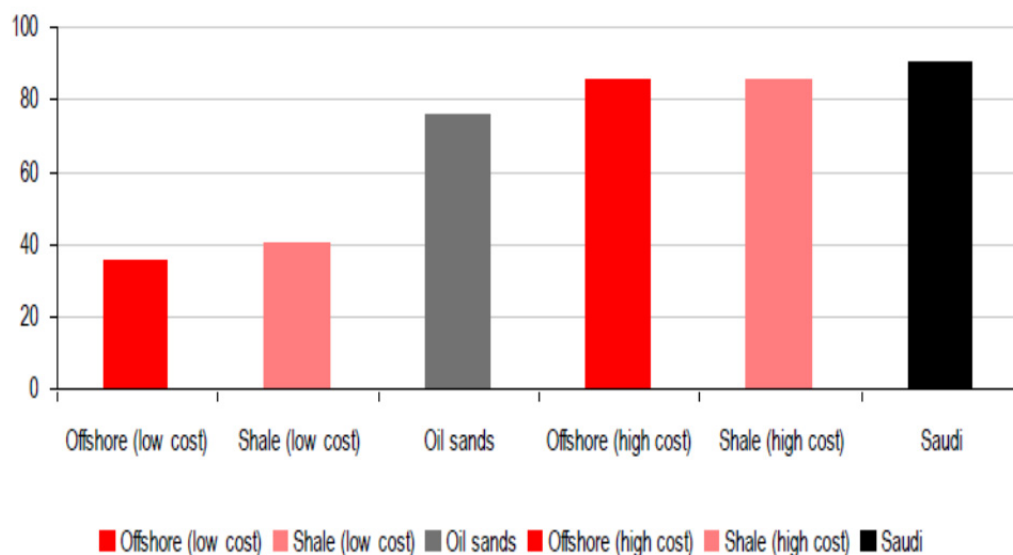
No immediate shale gas developments in Brazil

Another part of the shale story is the potential development of Brazilian shale gas reserves. According to a study published by the US Energy Information Administration¹, Brazil has a

Andre Loes
Economist
HSBC Bank Brasil S.A.
+55 11 3371 8184
andre.a.loes@hsbc.com.br

¹ EIA, *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, June 2013

Breakeven costs by project type (USD/barrel)



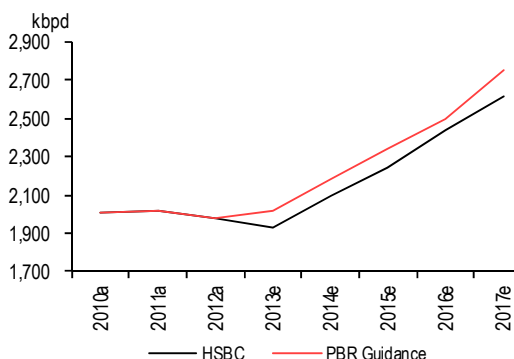
Source: HSBC estimates

reasonable amount of wet shale gas technically recoverable resources (TRR) – 245trn cu ft, which could represent around 3.5% of the TRR in the world.

However, some of the conditions that facilitate shale gas development in the US – such as the pipeline infrastructure that has already been built with good coverage, in addition to available rigs for drilling the wells – do not exist in Brazil, bringing the cost of exploitation closer to the category in the chart above called “Shale (high cost).”

As a result, with all the resources focused on the investment on the pre-salt oil reserves – a more competitive source of energy under the conditions that exist in Brazil – investments in shale oil and gas developments may not take place in the short term.

Brazil oil production forecasts (1,000 barrels/day)



Source: Petrobras and HSBC estimates

Short-term investment needed

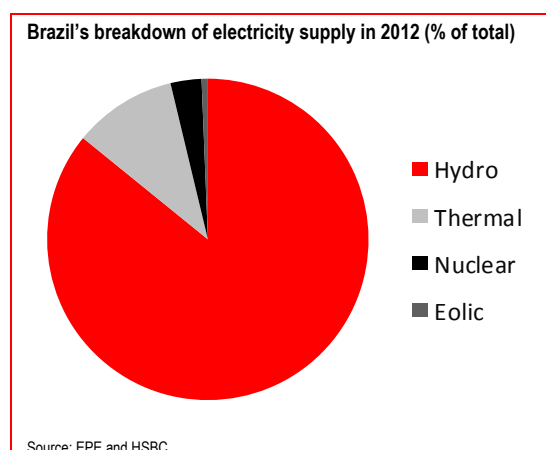
Over most of its history, Brazil has had an adequate balance between energy supply and demand. With the exception of the period after the two oil shocks of the 1970s, energy constraints have not been a limitation on growth.

It is fair to highlight that the expansion of energy supply expected in the coming decades may imply an escalation in the average cost of energy, as electricity will increasingly depend on the more costly thermal, wind, and variations of hydro generation.

Electricity aplenty

Brazil's vast hydro-electric potential has been developed over time, leading to an electricity sector dominated by hydro-energy.

In 2001, insufficient investment combined with negative hydrology led to a shortage of electric power for which the government's response – beyond the short-term measure of rationing – included building up significant spare capacity in conventional thermal electricity.



The table that follows shows the supply of and demand for electricity in Brazil over the last three years, as well as for the period January-May 2013. While oversupply has been observed, the mix of the supply may change – to a more costly thermal-based supply – whenever hydro generation is not as abundant. This has been the case since the end of last year.

Brazil electricity supply and demand (2013 data = January-May)

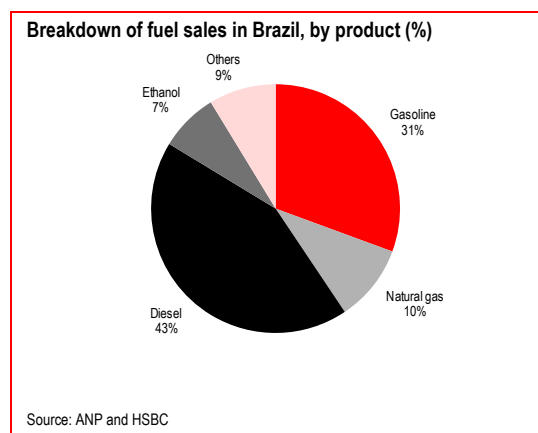
	2010	2011	2012	2013
Supply (Gwh)	476,377	493,780	513,814	219,300
Demand (Gwh)	418,654	430,411	448,246	191,541
Oversupply (%)	13.8	14.7	14.6	14.5

Source: EPE, ONS and HSBC

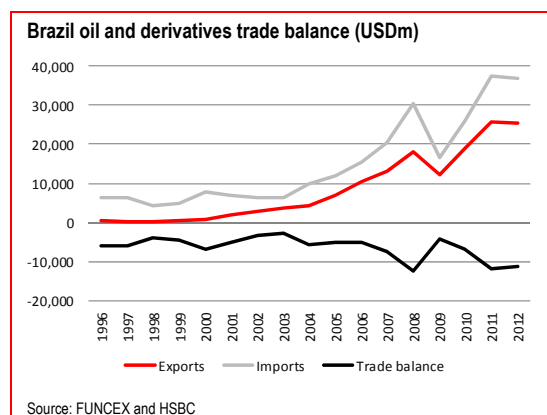
More stress on the oil side

The oil side of the energy balance has been less positive for Brazil over its history. The country suffered from a significant trade imbalance in oil and derivatives in the early stages of national production, which was aggravated in the 1970s with the rise in oil prices that followed the oil shocks of 1974 and 1979.

This situation led to the development of a massive program of ethanol production and change in the engines of the national fleet in order to use this renewable fuel. It also led to stronger efforts by Petrobras to increase the national production of oil. The chart below shows the current breakdown of the sales of fuels in Brazil, which highlights the unusual importance of a renewable fuel, ethanol.



These developments reduced the trade imbalance for oil and derivatives, and the external deficit for these products remained low for a long time. However, the trade imbalance has been widening since 2009, due to rising domestic demand, with the economy growing above the recent historical average in the second half of the last decade, combined with delays in investments and in the delivery of new increased domestic production capacity.



While demand growth may slow down as a result of lower GDP growth since the end of 2011, we believe there will not be a sustainable narrowing of the trade deficit until there is marked growth in domestic production, which will not be for some time. See our forecasts in the chart on the second page of this chapter.

Competition for investment could have negative short-term impact

When we consider the economy as a whole, the supply of energy does not seem to constitute an impediment to growth in the medium term.

However, it is worth remembering that the expansion of supply – especially oil production – is very capital-intensive, and as Brazil has low savings, currently at c16% of GDP, the resources available are insufficient to fund this effort. This means that Petrobras and other players need to resort to external resources to fund a pipeline of fixed asset investments expected to reach USD236bn over the next five years or so.

The emergence of US shale gas production represents another promising frontier in the oil and gas space, which could drain some resources – in the form of both equity and debt – previously allocated to the development of the Brazilian pre-salt wells, making financing more expensive. This could put further limitations on the speed of the expansion of the Brazilian domestic oil production.

Canada

- ▶ Unconventional oil will be the main focus of the projected CAD223bn of energy investment in Alberta over the next 10 years
- ▶ The US energy boom has different implications for Canadian oil and natural gas
- ▶ The historical natural gas trade relationship between Canada and the US is evolving; Canada could eventually become a net importer of US gas

Canada's unconventional transformation

Two unconventional transformations are under way in Canada's energy sector. One is related to oil, and the other to natural gas. As a result, future energy production, and exports, will increasingly be dominated by unconventional reserves.

However, both transformations must overcome major obstacles in the next few years. Oil sands developments face transportation infrastructure challenges as pipeline capacity constraints become pressing, while Canada's gas sector faces a challenge from the projected decline in US natural gas imports, which will occur before Asia-bound LNG exports from unconventional reserves in British Columbia become established.

See also 13 December 2012, [*Canada Economics: Transforming into an oil economy*](#).

Unconventional oil

Canada's unconventional oil reserves are dominated by the Alberta oil sands, which are the primary reason why Canada's proved oil reserves top 173bn barrels, making them the third-largest in the world as of January 2013. The oil sands are a mixture of sand,

clay and water surrounded by bitumen – a thick, sticky, heavy oil product that can be refined into synthetic crude oil. The oil sands are deemed unconventional owing to the complication and expense of the procedure for extracting the synthetic crude oil from the oil sands mixture.

Extraction of the useful synthetic crude oil from the oil sands begins with either surface mining, or an “in situ” process, a complicated oil well operation.

Surface mining involves scraping away the raw oil sands and transporting the material to facilities where the bitumen is recovered and upgraded to refinery-ready product. Only about 20% of all Canada's oil sands are shallow enough for surface-mining operations.

In situ processes are used to reach deeper oil deposits. One technique is steam-assisted gravity drainage (SAGD), where steam is injected into a deposit through one drilled well, heating the heavy oil and allowing it sink toward a second well through which the bitumen is retrieved. In situ methods are becoming increasingly common since 80% of Canada's oil sands are too deep for surface mining. Of the 97 oil sands projects in

David Watt
Economist
HSBC Bank Canada
+1 416 868 8130
david.g.watt@hsbc.ca

operation, under construction, approved, at the application stage, or announced, only 11 involve mining techniques. Mining operations do tend to have larger capacities (100,000 barrels per day or more) than in situ projects (few of which have a projected capacity above 60,000b/d), but they are also generally more costly. Break-even oil prices for mining projects can reach USD80/bbl to USD90/bbl, vs USD55/bbl to USD70/bbl for in situ projects.

Unconventional sources of oil accounted for 30% of oil production in 2001 and 51% in 2010, and are projected to account for 79% by 2030. The Canadian Association of Petroleum Producers estimates that, between 2012 and 2030, total Canadian oil production will increase 3.7% per annum, and almost all of the future production growth will come from unconventional sources, which are expected to increase at an average rate of 5.5% per annum. The association forecasts conventional oil production to rise by just 0.3% per annum. To generate this consistent upswing in production, the unconventional oil sector will need massive investment. Unconventional oil will be the main target of the projected CAD223bn of investment into the energy sector in Alberta over the next 10 years.

Unconventional natural gas

Unconventional natural gas in Canada largely consists of tight gas and shale gas; coalbed methane plays a much smaller role. Tight gas refers to deposits of gas locked in low permeability, or “tight,” sandstone and carbonate formations, which require some form of fracturing to release the gas. Shale gas refers to deposits of gas trapped in shale, a soft, sedimentary rock that is not very porous, and also requires some form of fracturing for release.

There are unconventional natural gas plays all across Canada, from British Columbia to Nova

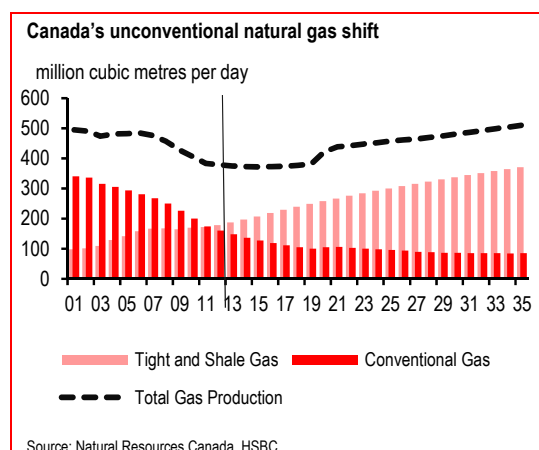
Scotia. The US-based Energy Information Administration (EIA) estimates that Canada has 573trn cubic feet of technically recoverable shale gas.

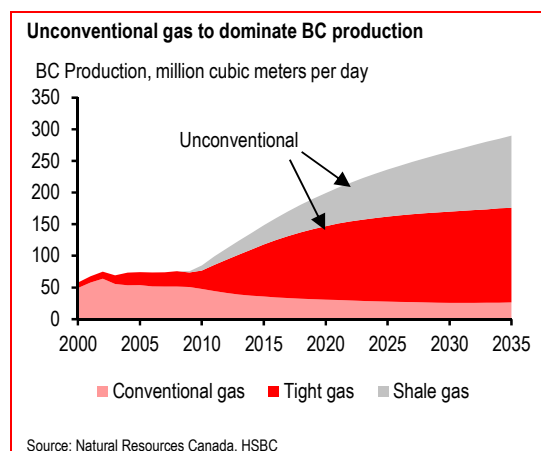
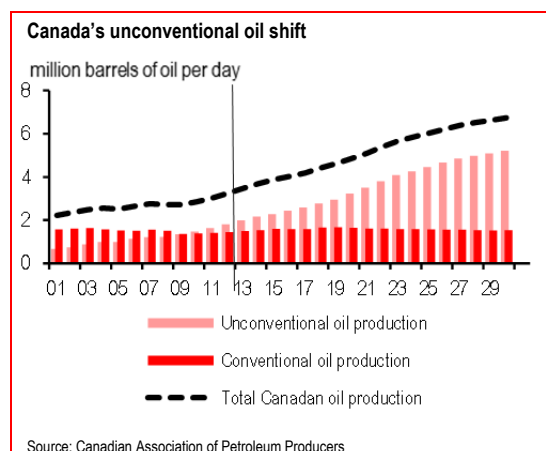
Almost 60% of those recoverable gas reserves are in British Columbia and are expected to form the basis for several proposed LNG export facilities on BC’s Pacific coast.

Tight and shale gas production overtook conventional production in 2012, and accounted for 47% of total natural gas production. The shift is expected to continue. By 2030, we expect tight and shale gas projects to account for 70% of production, and almost all of Canada’s natural gas exports.

Despite the projected steady increase in the production of unconventional gas in the coming years, total natural gas production will remain flat until 2020, when production from the Northern Territories commences. For the next several years, increased unconventional natural gas production will just offset declining conventional production. We expect total gas production to remain below 2007 levels until 2030.

The longer-term production profile for natural gas differs markedly from that discussed for oil, where total production is expected to increase consistently, at an average growth rate of 3.7% per annum through 2030.



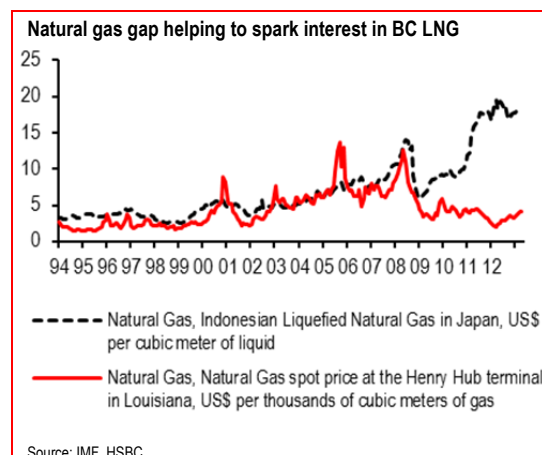


To develop its unconventional energy sector and put in place the infrastructure required for LNG exports, investment in British Columbia's energy sector is expected to total CAD67.3bn in over the next 10 years, per Natural Resources Canada. British Columbia is projected to become an increasingly important natural gas production hub. In 2000, Alberta accounted for over 80% of Canadian natural gas production, but the balance has been tilting toward British Columbia in recent years: from below 20% prior to 2007, its share of Canadian natural gas production will rise to over 50% by 2025, largely from unconventional sources. The share of BC gas coming from unconventional sources will increase to over 90% from below 50% in 2010, according to Natural Resources Canada.

At present, we are tracking 12 proposed LNG export projects. Of those, 11 are in British Columbia and involve substantial foreign participation with partners from the US, Japan, Korea, Malaysia, China, and Australia. One project is in Nova Scotia. Three of the BC projects (Kitimat LNG, LNG Canada, and the BC LNG Export Co-operative) have export licences and are poised to begin production and LNG exports by 2020.

The largest project is LNG Canada, whose export licence was granted in February 2013, permitting the project to export up to 24m tonnes of natural gas per annum (mtpa). It is expected to come on line in 2019.

Exports of LNG from British Columbia are primarily destined for the Asian market. There are three reasons for this: the spread between North American and Asian LNG prices; expectations of rising demand for natural gas in Asia; and the US shale and gas boom, which is curtailing US natural gas imports including those from Canada. In Eastern Canada, the proposed Goldboro LNG terminal in Nova Scotia is focused on Europe, having recently signed a 20-year export deal with a German utility.



US energy imports by country

Natural gas (% of total, 2012)		Crude oil (% of total, 2012)	
Canada	94.4	Canada	24.9
Trinidad and Tobago	3.6	Saudi Arabia*	13.3
Qatar	1.1	Mexico	12.3
Yemen	0.6	Venezuela*	9.7
Egypt	0.1	Nigeria*	8.6
Norway	0.2	Iraq*	5.1
		OPEC	47.1

Source: EIA, HSBC

*OPEC members

Evolving Canada-US natural gas trading relationship

As Canada's LNG export capacity is developed, the country's reliance on the US as the sole destination for exports should decrease. This shift is critically important, since US natural gas imports are declining. US exports are also expanding, and the US is poised to eventually become a net natural gas exporter.

At present, Canadian natural gas exports are intimately linked to pipeline connections with the US. In 2012, the US was the sole destination for Canadian natural gas exports, as has been the historical norm. However, the diversification of natural gas exports will not happen soon, or quickly: Although LNG exports to Asia are expected to grow from 2020 onward, they will remain small scale until 2019.

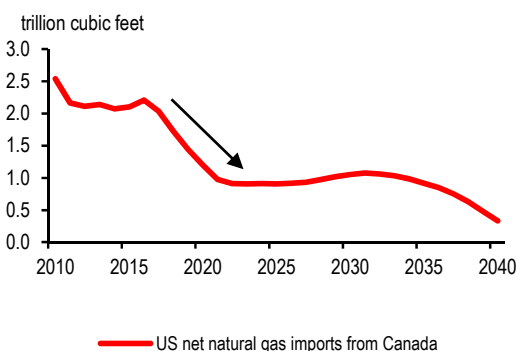
The impact of the US shale gas boom, however, is already evidenced by the decline in US imports of natural gas from Canada. In 2012, Canada accounted for over 94% of US natural gas imports, and although this was higher than its share in recent years, it demonstrates that Canada accounts for such an out-sized proportion of US imports that it cannot avoid fallout from the decline in US gas imports. Since 2007, total US imports of natural gas have dropped almost 32% by volume, while US gas imports from Canada alone are down almost 22% – so the negative impact on Canada has been less severe than for other countries supplying natural gas to the US. Non-Canadian US imports of natural gas, largely

LNG, have declined by 79% since 2007. As a result, non-Canadian imports of natural gas to the US have shrunk from 16% of total imports in 2007 to less than 5% in the 12 months through March 2013. Unlike in oil, then, very little US market share is available for Canada to grab in order to cushion the blow of lower US demand.

Looking ahead, the outlook for Canadian natural gas exports to the US remains challenging, highlighting the need to build the infrastructure necessary to diversify the export base. The EIA projects that US net natural gas imports from Canada will fall by a further 50% between 2015 and 2020, decreasing again after 2030. US imports of natural gas from Canada are projected to drop at an average rate of 1.4% per annum between 2010 and 2035. Meantime, demand for natural gas in Canada will continue to grow in the coming years. Between 2010 and 2035, Canadian demand for natural gas will increase at an annual average rate of 2.1%, as production increases by 0.9% per annum.

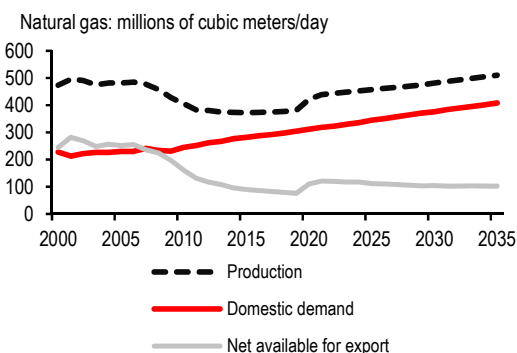
With Canadian demand outpacing production, the net amount of Canadian natural gas available for export is expected to decline. This is true even though natural gas available for export should increase in 2020 as production in the Northern Territories jumps, and despite projected increases in LNG exports to Asia. Between 2012 and 2030,

US imports of natural gas from Canada set to tumble



Source: Energy Information Agency, HSBC

Canadian natural gas demand steadily increasing, along with production, export supply to lag



Source: Natural Resources Canada, HSBC

the amount of natural gas available for export is expected to fall by 0.6% per annum. By 2035 Canada's natural gas exports will be 60% below 2001 levels.

With natural gas production shifting toward British Columbia, and becoming increasingly focused on LNG exports to Asian markets, Canadian natural gas demand will result in rising imports of natural gas from the US. The US EIA projects that pipeline exports of natural gas to Canada will increase at an average rate of 2.5% per annum, and will almost double in volume terms between 2010 and 2035. With US exports of natural gas to Canada on the rise, Canada's conventional (pipeline-oriented) natural gas trade will almost be in balance by 2035. Indeed, there is a risk that it could eventually become a net gas importer from the US. Though we do not at present expect such a development to occur, it is clear that the historically one-way trading relationship between Canada and the US is changing. It will no longer feature Canada as producer and exporter and the US as importer.

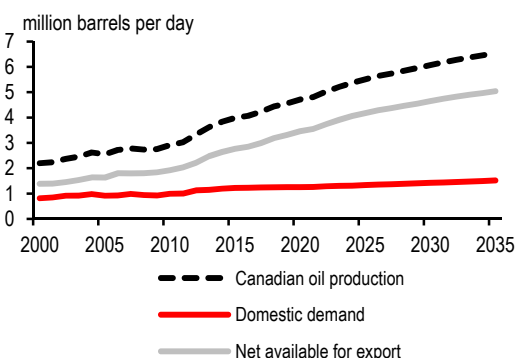
Implications of US oil and natural gas boom

The evolution of the natural gas trading relationship between Canada and the US will be particularly evident in the next few years, before Canadian LNG exports to Asia gain momentum.

Canadian production is expected to be flat, demand is expected to grow, and US shale gas production is expected to sharply curtail imports. As we noted, between 2015 and 2020, US net imports of natural gas are projected to decline by a further 50%.

The implications of the US unconventional energy shift are somewhat different for Canadian oil. In oil, much of the projected increase in unconventional production will be exported, as Canadian oil demand looks set to increase at a much slower pace than oil production.

Canadian oil demand to lag production, amount available to export to rise with production



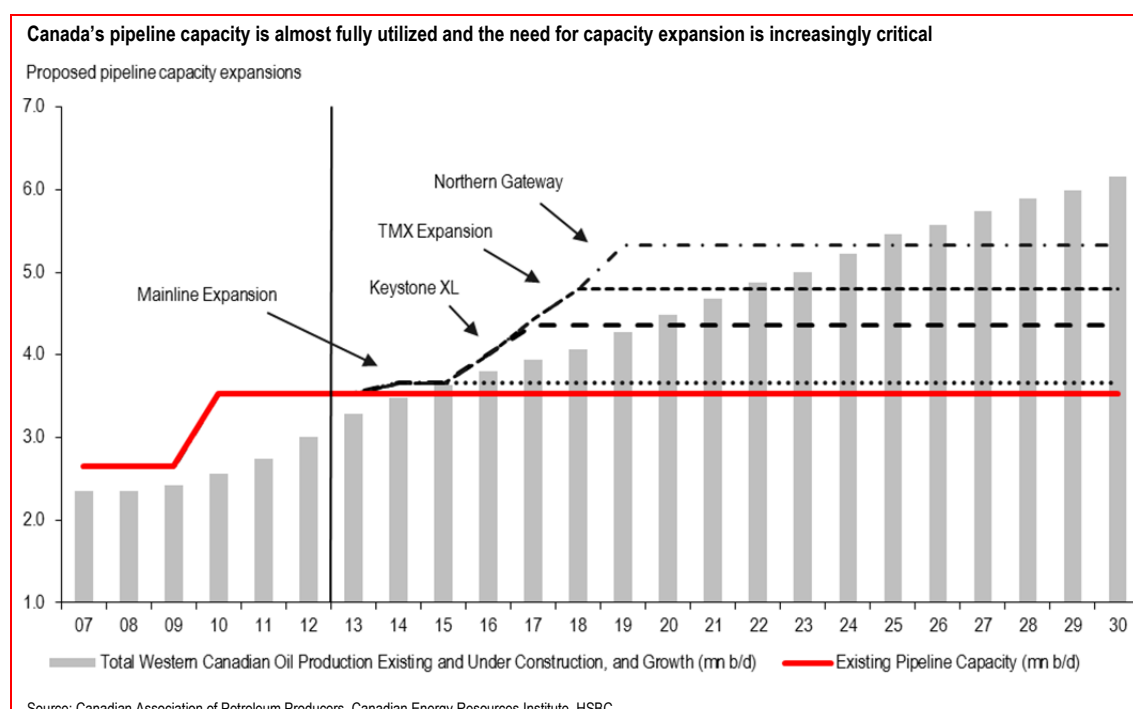
Source: Canadian Association of Petroleum Producers, HSBC

Moreover, US oil imports from Canada have continued to increase despite an overall decline in oil imports. And even though Canada is already the largest single source of US oil imports, it has grabbed a greater share of the US oil import market in recent years.

We continue to expect that the ongoing development of Canada's oil sands will cause oil to play an increasingly larger role in Canada's total exports, and that oil's share of Canadian exports will almost double from 15% in 2012 to 30% in 2025. Much of that is still expected to go to the US, primarily to refineries on the Gulf Coast, although we also foresee Canada developing greater export capacity to Asian markets. However, for that to occur, the infrastructure to transport

unconventional oil to market must be put in place. This will depend on efforts to build pipelines to Canada's west coast, the US Gulf Coast, and Eastern Canada, as well as the expansion of rail capacity. Several proposed pipeline projects are facing varying degrees of opposition, and the environment will be particularly difficult in the next few years, as existing pipeline capacity is almost fully utilized.

As a result of Canada's transformation into an unconventional energy producer and exporter, we believe the western provinces will remain key economic drivers in the coming decades, and a key destination for investment. However, there are major obstacles to the development of unconventional oil and natural gas reserves that will be particularly challenging in the next few years, and that must be overcome in order to fully benefit from the opportunities available.



China

- ▶ The fledgling shale industry is moving forward, but slowly
- ▶ China is teaming up with companies to acquire the necessary technology
- ▶ The country's 2015 and 2020 production targets are ambitious and many challenges remain

In the pipeline

Estimates vary but it is widely accepted that China is home to the world's largest reserves of shale gas. The big challenge is how to get them out of the ground. Exploration is at an early stage and we do not think significant levels of production will be possible before 2020. In short, the shale gas industry in China is still some years away from having a material commercial impact on the country's energy supply.

China is already the world's largest energy consumer and demand is only going to continue to grow. Beijing policymakers want to rely less on coal – which makes up 70% of China's energy

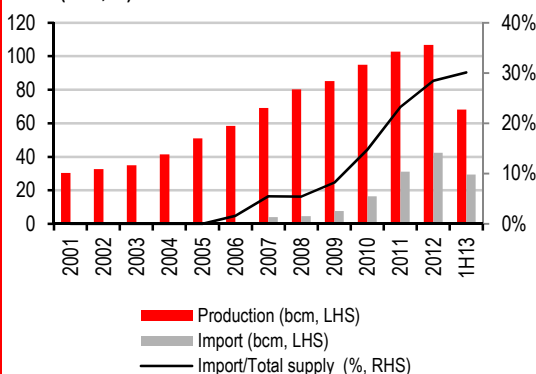
supply – and move on cleaner fuels such as natural gas, which currently represents only 4% of the energy mix. The target in the 12th five-year plan (2011-15) is to raise the share of natural gas to 8% by 2015.

China became a net natural gas importer in 2007 and imports have since increased. Data released by the National Development and Reform Commission, the country's leading economic planning body, shows that China produced 108bn cubic metres (bcm) of natural gas in 2012, up 6.5% y-o-y; imports of natural gas were 42.5bcm, up 31% y-o-y. The nation's dependency on imported natural gas for 2012 was 28%, up from only 2% in 2007. This underlines the need to

Thomas C Hilboldt*, CFA
Head of Oil, Gas and Petrochemicals, Asia Pacific
The Hongkong and Shanghai Banking Corporation Limited
+852 2822 2922
thomaschilboldt@hsbc.com.hk

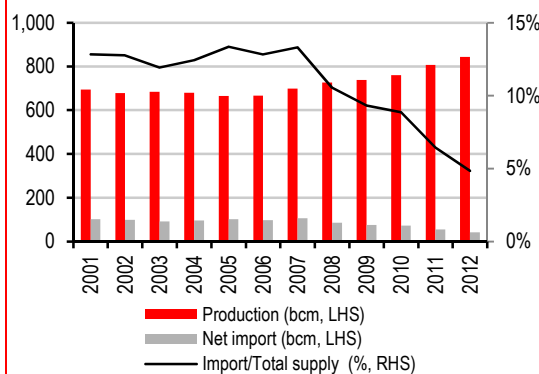
*Employed by a non-US affiliate of HSBC Securities (USA) Inc, and is not registered/ qualified pursuant to FINRA regulations

China natural gas supply and import dependency ratio (bcm, %)



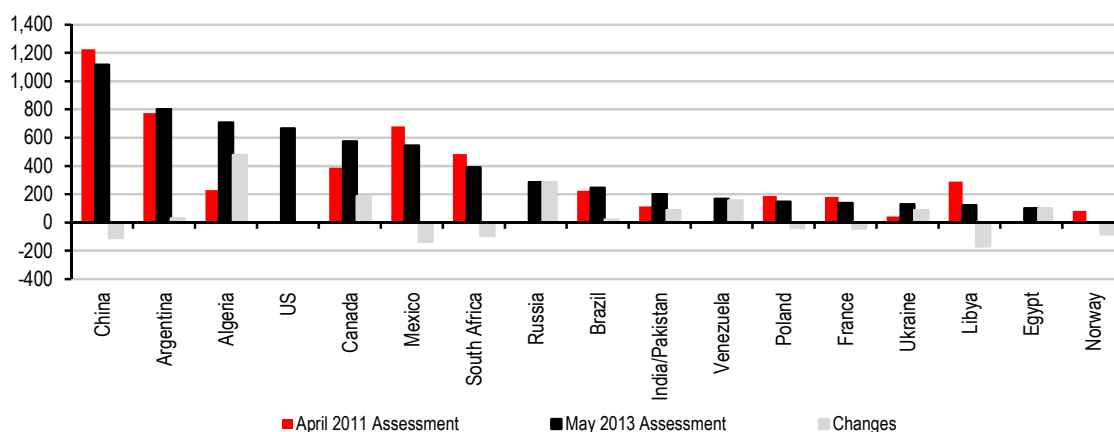
Source: CEIC, HSBC

US natural gas supply and import dependency ratio (bcm, %)



Source: EIA, HSBC

Comparison of 2011 and 2013 EIA/ARI estimates of risked, technically recoverable shale gas resources (tcm)



Source: EIA and Advanced Resources International: Technically Recoverable Shale Oil and Shale Gas Resources, June 2013

maintain stable growth of domestic supply and shale gas fits the mandate. The question is, how quickly could this happen?

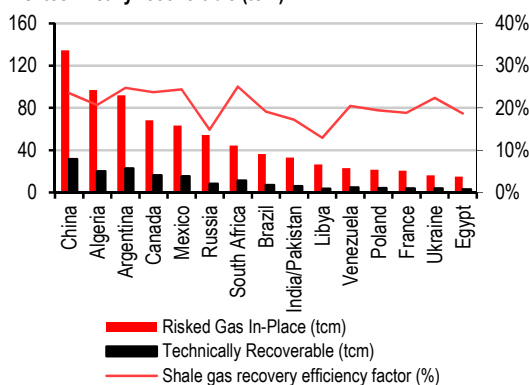
Progress

China's government puts the country's technically recoverable shale gas reserves at 25trn cubic meters (tcm), considerably below the US Energy Information Administration's estimate of 31.6tcm. To put this in context, US reserves are believed to be 18.8tcm and, more significantly, US shale production in 2011 rose to 224bcm, representing almost 35% of the country's total gas output. In China, commercial production of shale gas has yet to begin.

Beijing hopes this will soon change and its production targets for shale gas are ambitious – 6.5bcm in 2015 (3% of total project gas production) and 60-100bcm by 2020. We believe these targets will be difficult to meet even though China's two biggest oil companies, Sinopec and PetroChina, have begun drilling appraisal wells with some success.

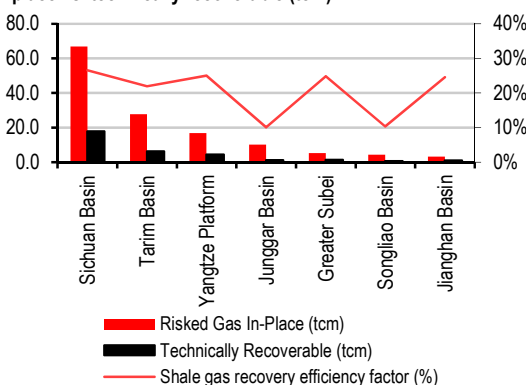
Exploration will focus on the following areas: Sichuan, Chongqing, Guizhou, Hunan, Hubei, Yunnan, Jiangxi, Anhui, Jiangsu, Shaanxi, Henan, Liaoning, and Xinjiang. The most promising deposits are in the Tarim Basin in the northwest, the Ordos Basin in the north-central part of the country, and the Sichuan Basin in the southwest.

Shale gas resources in major countries – risked gas in-place vs. technically recoverable (tcm)



Source: EIA, Technically Recoverable Shale Oil and Shale Gas Resources, June 2013, HSBC

China shale gas resources in major basins – risked gas in-place vs. technically recoverable (tcm)



Source: EIA, Technically Recoverable Shale Oil and Shale Gas Resources, June 2013, HSBC

In January 2013, the Chinese Ministry of Land and Resources (MLR) held the second shale gas block auction and awarded 19 exploration blocks to 16 domestic companies in an attempt to introduce broader competition in an industry long-dominated by state giants. However, media reports suggest that some may lack the necessary expertise and could struggle to raise funds.

An MLR-led survey of the 19 blocks showed that seismic processes had started in only three or four, with the rest at a very early stage (see table below for an update). Given the slow progress, the third auction, originally planned for later this year, is likely to be held later than anticipated. According to an MLR official, a maximum of 10 blocks will go under the hammer.

China is also teaming up with multinational companies to acquire the technology and skills necessary for shale gas exploitation. For example,

China National Petroleum Corp, the state-controlled parent of PetroChina and the country's biggest oil and gas company, has signed a production sharing contract with Shell.

PetroChina has entered a long-term partnership with BP, and similar co-operation deals with Total, ConocoPhillips, and Chevron are also in place. Sinopec is planning its first natural gas and LPG-based ethylene cracker in East China in anticipation of increasing shale gas production after 2018.

To increase its level of technical knowledge, China is also investing in US shale gas joint ventures. Earlier this year, Sinopec bought a USD1bn stake in the Mississippi Lime shale formation from Chesapeake Energy.

Current status of the blocks awarded in China's second shale gas block auction (as of June 2013)

No.	Block name	Area (km2)	Block owner	Progress
1	Suiyang, Guizhou	1,204	Huadian Coal Industrial Group	Drilling started
2	Fenggang-1, Guizhou	1,053	China Coal Geology Engineering Corp.	Exploration started, field research ongoing
3	Fenggang-2, Guizhou	1,030	Huaying Shanxi Energy Investment	Exploration started, field research ongoing
4	Fenggang-3, Guizhou	1,167	Beijing Titan (Taitan) Tongyuan Natural Gas Resources Technology	Exploration started, field research ongoing
5	Cengong, Guizhou	914	Tongren Energy Investment	N/A
6	Qianjiang, Chongqing	1,272	Chongqing Energy Investment Group	N/A
7	Youyang East, Chongqing	1,002	Chongqing Mineral Resources Development	In April 2013, Huaneng International Power Development Corporation increased its equity share of Chongqing Mineral Resources Development from 29% to 65%
8	Chengkou, Chongqing	1,020	State Development and Investment Corp.	Good quality block; expects to complete 2D seismic survey and surface geologic mapping by August 2013
9	Longshan, Hunan	878	Hunan Huasheng Energy Investment and Development	Exploration started in May 2013; underground geologic mapping will start in July 2013
10	Baojing, Hunan	1,190	Shenhua Geological Exploration	Co-operated with CNPC's oil service team in 2D seismic survey in May 2013
11	Huayuan, Hunan	400	China Huadian Engineering	Feasibility studies completed; 3-year exploration plan
12	Sangzhi, Hunan	760	China Coal Geology Engineering Corp	3-year exploration plan, with target volume and investment
13	Yongshun, Hunan	982	Hunan Shale Gas Development	Exploration and development started
14	Laifeng-Xianfeng, Hubei	369	Huadian Hubei Power Generation	N/A
15	Hefeng, Hubei	2,306	Huadian Hubei Power Generation	Exploration started in April 2013; field geologic survey completed; expects to find commercially feasible blocks in two years
16	Xiuwu, Jiangxi	598	Jiangxi Natural Gas Holdings	Initial investment committed; exploration started in May 2013; a total of RMB70m will be spent in 2013 on geologic and 2D seismic surveys, as well as 4 data wells and 1 wildcat well
17	Lin'an, Zhejiang	580	Anhui Province Energy Group	N/A
18	Wenxian, Henan	1,378	Henan Yukuang Geological Exploration and Investment	Construction plan completed
19	Zhongmou, Henan	1,396	Henan Yukuang Geological Exploration and Investment	Seismic survey started
Total		19,505		

Source: China's Ministry of Land and Resources

Challenges

A number of problems will have to be solved before production on a commercial scale can begin. They include:

- ▶ **Geology:** Most of China's seven major onshore shale basins are in mountainous and relatively remote locations, with limited access to pipelines, transport, and end users.
- ▶ **Technology:** China's shale deposits are deeper underground than in the US, 5,000-7,000m in China vs 3,000-4,000m in the US, making it difficult to adapt the technology that has worked in the US. They also have a higher clay content, making them more difficult to fracture. According to Sinopec chairman Fu Chengyu, China has sufficient shale development technology, but lacks equipment and infrastructure.
- ▶ **Water:** Producing shale gas requires large amounts of water, which is scarce in many parts of China, especially in regions that have the largest shale gas reserves.
- ▶ **Lack of competition:** The three national oil companies hold blocks that have more easily recoverable shale gas, but lack the incentive to tap them because tight gas and coal-bed methane offer better returns and thus are given higher priority. Private companies which are more willing to enter the market have neither the technology nor the financial resources required.
- ▶ **Pricing:** According to the 12th five-year plan, the price of shale gas was fully liberalized in 2011. However, as there is no commercial supply yet, it is not clear how much users are paying for non-commercial volumes or how much they would be willing to pay when commercial shale gas volumes materialize.
- ▶ **Infrastructure:** China lacks the pipeline infrastructure necessary to transport shale gas from where it is found to the most populated areas. The first shale gas pipeline is being built in Sichuan province by CNPC, with work starting in June 2013; many more branch pipeline systems will be needed to carry the gas to the main distribution centers.
- ▶ **The environment:** According to some studies (and disputed by others), hydraulic fracturing could contaminate groundwater. Also, in some countries, hydraulic fracturing has been linked to earth tremors. China does not have shale gas-specific environmental regulations and oversight in place yet.

Mexico

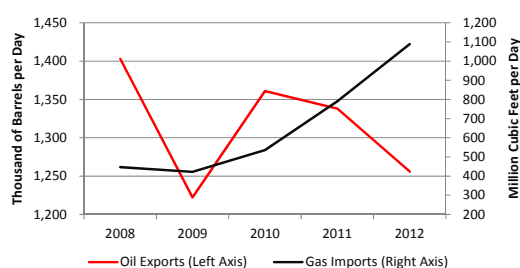
- ▶ The US's reduced dependency on international sources of energy is a benign shock for Mexico, a net oil exporter
- ▶ The impact on Mexican GDP growth and the energy trade balance between these two countries should be largely neutral
- ▶ The US becoming an exporter may be beneficial for shale gas now, but longer term, the US will become a competitor to Mexico

The new energy order: mostly neutral for Mexico

The US's diminished dependency on international sources of energy may reduce energy constraints on global economic growth. However, we see the overall impact on the Mexican economy as generally neutral for both GDP growth, and oil and gas trade.

Mexico is a net oil exporter and a natural gas importer over the short and medium term; however, as it is ranked #6 among the countries with the highest volumes of recoverable shale gas resources, according to the US Energy Information Agency, it may become a major producer and exporter in the long run. Moreover, the country is now undergoing a process of reform aimed at modernizing the energy sector.

Mexico: Oil exports and gas imports



Source: PEMEX

We believe there are three issues that the Mexican economy must deal with in the future: (1) lower US demand for international energy; (2) the transformation of the US into a net gas exporter; and (3) the lessening of overall energy constraints on global economic growth.

Our view on these issues is the following:

- (1) Assuming that the US remains a net oil importer with high demand, Mexico should have no problem continuing to be a preferred oil supplier.
- (2) Mexico is set to become a significant importer of US gas in the short and medium terms. However, this situation may change if technical capabilities and financing become available that allow Mexico to develop its own shale gas production and become a competitor.
- (3) With lower energy supply scarcity, constraints on growth would tend to decrease, supporting increased trade. That would benefit very open and export-oriented economies, such as Mexico.

Sergio Martin
Mexico Chief Economist
HSBC Mexico S.A.
+52 55 5721 2164
sergiomartinm@hsbc.com.mx

Lorena Dominguez
Senior Economist
HSBC Mexico S.A.
+52 55 5721 2172
lorena.dominguez@hsbc.com.mx

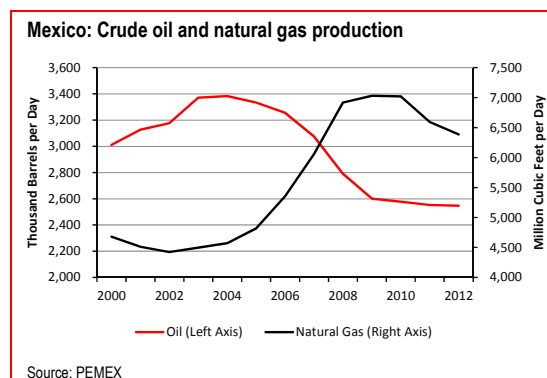
Lower US oil demand should not hit Mexico

Lower US demand

The surge of crude oil and natural gas production in the US from unconventional shale resources has reduced the country's demand for imported energy. Even so, it is still expected to be a net importer.

Mexico's oil production and exports

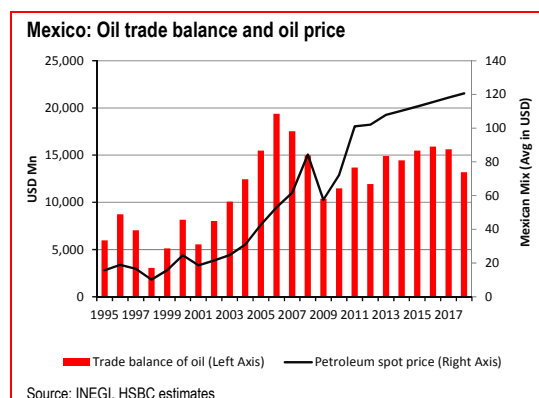
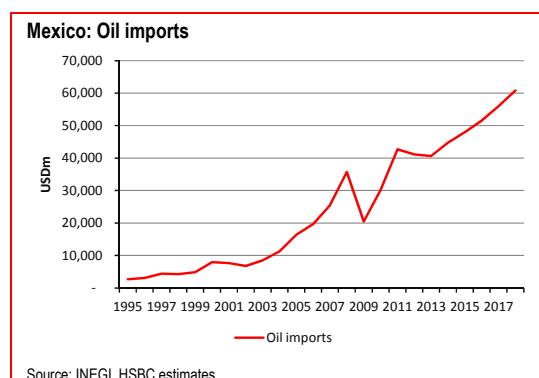
At present Mexico produces 2.5mbd of crude oil and exports about 1.3mbd – currently worth around USD47bn – almost 80% of which is exported to the US. Exports of oil derivatives total 0.2mbd, equivalent to USD8.0bn. These volumes are expected to increase in the future if the energy reform, due to be presented to congress in 4Q13, is approved.



On our forecasts, oil production could increase gradually, returning to the 2004 production peak of 3.4mbd in 5 to 10 years' time. Nonetheless, we expect exports to grow at a slower pace, since domestic consumption will also increase, from around 50% of total production to close to 60% in the medium term. Consequently, Mexican oil exports may reach 1.5mbd or so – not very different from the levels we see currently. If Mexico maintains its oil exports to the US unchanged at 80%, it will be covering practically the same proportion as now.

Therefore, we do not expect lower oil demand from the US to affect Mexico since its market share will probably not change. Moreover, its proximity to the US should ensure that Mexico remains a preferred oil source, on the same footing as Canada.

We estimate that in the next 5 to 10 years, Mexico will continue to import substantial amounts of gasoline and oil derivatives. Imports currently total about USD40bn, or 1.0mbd. Consequently, the oil trade balance was around USD12bn, or 1.0% of GDP, in 2012.



We note that international oil price fluctuations have relatively little impact on Mexico's oil trade balance, since they affect exports and imports in opposite directions, thereby cancelling out much of the positive or negative impact.

US gas exports: a benefit to Mexico now; competition later

US as a shale gas exporter

The possibility of the US becoming a net gas exporter is relevant in that it would reduce energy constraints at a global level. The US is already exporting gas to Mexico, and when a pipeline system in Mexican territory is finished in a few years, gas exports to Mexico might increase even further.

This is a positive development for Mexico, which has been unable to adequately exploit its gas shale resources owing to the lack of technology and financing. Gas imports help supply the necessary energy through a corridor that extends to the US border from the center of Mexico.

Mexico becoming a gas exporter

According to the US Energy Information Agency estimates, Mexico is ranked sixth among the countries with most recoverable shale gas resources, behind the US, China, Argentina, Algeria, and Canada. However, it faces two obstacles to becoming a strong gas exporter. First, it is a late starter in an environment of low prices that offer little incentive for costly investments; second, it will take time to establish the technical capabilities needed to exploit its shale resources – and to raise the necessary capital.

A key factor in overcoming these obstacles is the energy reform slated to be presented to congress in 4Q13 (see 22 August 2013, [Mexico Economics & Strategy: The impact of bold energy reform](#)). If all goes well and constitutional changes are made that allow efficient private investment in the sector, we believe adequate technology and financing could become available through foreign investment. Moreover, with respect to the first obstacle, we do not think that a decline in US energy imports over the next five years will necessarily offset growing global energy demand.

If demand continues to grow, prices may become higher, encouraging investment in the sector.

Lower global energy constraints: good for exporters

While it is obviously beneficial for everybody if there are fewer energy constraints on global economic growth, it is particularly positive for countries that are very open and have strong export platforms that support a dynamic market. This is precisely the case for Mexico, which has a major export platform, borders with the US, and has strong connections with Latin America and Europe.

Furthermore, if the US benefits from the loosening of global energy constraints, Mexico should also benefit by association, since its exports are highly correlated with US exports to the rest of the world, and with the US economy in general.

As already noted, one of Mexico's main competitive advantages is its proximity to the US, which allows it to contain its transportation costs. However, reduced energy constraints could therefore adversely affect the country by allowing other, more-distant countries to become more competitive.

Even if this proves to be the case, though, we would expect it to diminish rather than eliminate Mexico's advantage. We also note that Mexico's competitiveness does not stem solely from transportation costs, but also from relatively cheap



labor and time of delivery, as well as easy access, thanks to the North America Free Trade Agreement (see [*Mexico Economics & Equity Strategy: Mexico Handbook, competitive, open, and only a truck ride away*](#), October 2012).

Middle East

- ▶ The Middle East's pivotal role in the global supply of conventional oil dominates its economic profile and is the key driver of growth
- ▶ Production costs are competitive and reserves are abundant, but dependence on rising oil receipts leaves key exporters vulnerable to structural changes in the global energy mix
- ▶ Developing limited non-conventional hydrocarbon resources not yet a policy priority

Vulnerable

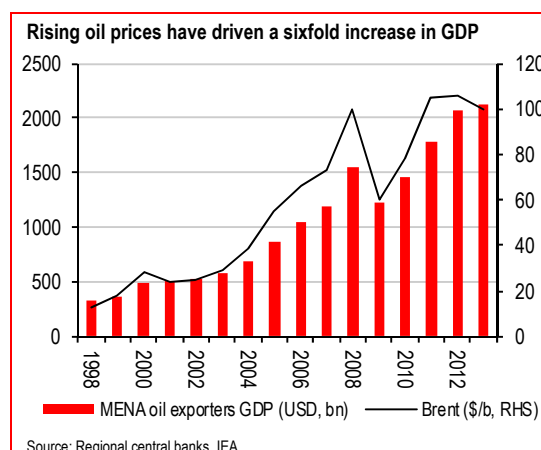
Some may look at the development of non-conventional hydrocarbons and lower energy costs for economic salvation; however, for the Middle East, there are few upsides to the shale revolution. Although it has some shale reserves, the volume is modest in global terms, paling against the vast conventional oil resources they command, and they are much more difficult to exploit.

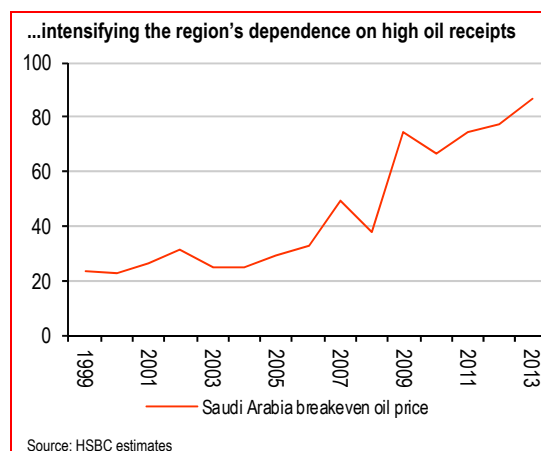
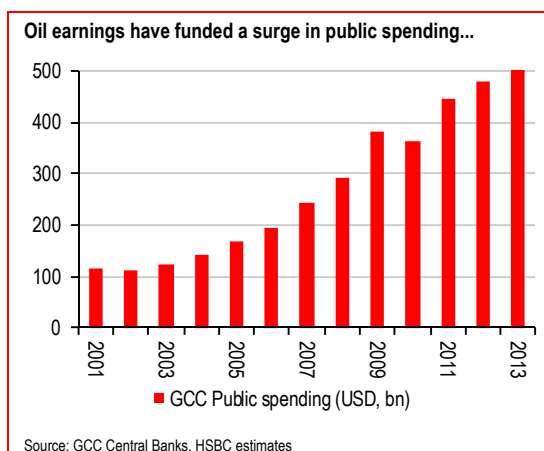
The low cost of conventional oil and gas production across much of the Middle East, and the region's well-established energy infrastructure, should ensure that its oil and gas production remains commercially viable in all foreseeable circumstances. However, the oil exporters' near-total dependence on high energy receipts to fund their external account balances and finance rapidly rising levels of public spending leave them vulnerable to any softening in conventional oil demand that might cut export volume or lead to lower prices.

Oil-intensive economies

The reliance of much of the region on oil receipts is difficult to overstate. In the Gulf, oil is the dominant generator of foreign exchange and the primary source of government receipts. In Saudi Arabia, for example, the net earnings of the state-owned oil firm, Saudi Aramco, provides 90% of government budget revenues and generates 85% of the kingdom's export earnings. Put more starkly, we estimate that Saudi Arabia has a non-oil budget deficit equivalent to around 50% of GDP this year. Similar non-oil budget

Simon Williams
Economist
HSBC Bank Middle East Ltd
+971 4 423 6925
simon.williams@hsbc.com





shortfalls are generated in the other oil-rich states, none of which raise taxes on personal income.

As well as supporting its domestic and external balances, oil receipts are a prime driver of growth. In Saudi Arabia, the oil industry generates more than 40% of nominal GDP – a remarkably high ratio for a single industry in a large economy, and one matched in other oil-intensive economies in the region. If anything, however, the figure understates its broader impact, given that oil-funded government spending is the dominant driver of domestic demand and the public sector is a key source of employment. Oil earnings are also a primary driver of credit trends. The depositing of energy company surpluses with local banks and the recycling of export receipts through public spending have a direct impact on bank liquidity.

Oil receipts are also key to the dollar-peg currency regimes prevalent across the Middle East, leaving the Gulf states with large current account surpluses that have given central banks the means to fix the value of their currencies without imposing FX controls. They have also provided the motive for the currency regime, sparing the Gulf states the FX volatility that would otherwise come with moves in oil prices, and tying the local currency to dollar-denominated oil export receipts.

Growing dependence

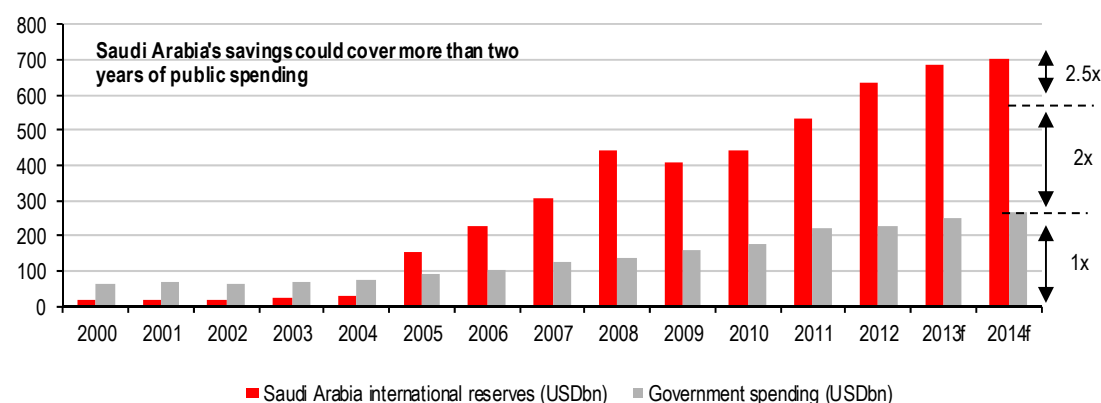
While regional policy makers have placed great emphasis over the past decade on diversifying economies away from oil, by many measures their reliance on hydrocarbon receipts is actually rising. As oil earnings have gained, public spending has risen sharply, all but quadrupling in the Gulf over the past decade. With fiscal outlays funded so heavily by oil receipts, this has driven up the oil price the government requires to balance its budget.

In Saudi Arabia, for example, the “breakeven oil price” has risen from USD25/bbl in 2004 to around USD85/bbl today and is likely to exceed USD100/bbl by 2016 as public spending continues to gain. Elsewhere, the breakeven oil price is higher still; Algeria and Bahrain, for example, balance their budget at around USD120/bbl, while the IMF estimate that Iran requires an oil price of USD140/bbl.

The region’s leading oil exporters have room for manoeuvre. Over the past decade of rising oil receipts, most have been able to pay down debt and build up their stocks of foreign assets.

Abu Dhabi, for example, is estimated to have up to a USD1trn in overseas assets – more than sufficient to meet the needs of a local national population numbering less than a million in the event of an oil price drop. Saudi Arabia has the

The oil exporters have considerable room for manoeuvre



Source: SAMA, HSBC estimates

largest population in the Gulf, but SAMA alone has assets of close to USD700bn – a sum sufficient to fund around three years of public spending.

What could shale do?

Nevertheless, the region's oil states remain acutely sensitive to oil price trends, and shale development raises profound questions over their economic strategies.

At the very least, rising shale production in North America will reduce US demand for Middle Eastern crude oil and LNG, accelerating a trend that has already seen Asian consumers displace those in the West as a prime source of demand. Technically, this will require changes in shipping routes and transport infrastructure and could lead to a change in the benchmark crude against which Middle East oil is priced. Less tangibly, it may also bring with it a change in regional political and strategic ties if reduced dependency on Middle Eastern energy prompts the US to reduce their military involvement in the region. The shift could be particularly marked if Asian economies more reliant on the smooth flow of Gulf crude seek greater influence in the region.

The abundance of low cost hydrocarbon energy in the US may also undermine the region's efforts to

develop its industrial base. Access to low-cost energy and hydrocarbon inputs has been the key advantage Gulf producers of, for example, petrochemicals and aluminum, have been able to enjoy over the past decade and are at the center of expansion plans. That may be compromised, however, by falling costs of gas in the US, which can offer business and operating environment advantages over the troubled Middle East.

Weaker OPEC

Growth in non-conventional oil supplies could also put a cap on demand for Middle Eastern crude, weakening the power that regional OPEC members have to influence prices. This could lead to additional price volatility, complicating considerably regional governments' fiscal planning process.

More seriously, the development of shale energy resources could bring the era of rising oil revenues to a close, particularly if emerging market energy demand were to weaken. If this were to lead to oil prices holding flat at their current USD100/bbl level in real terms, then we would expect all but the very richest of the region's oil states – Kuwait, the UAE, and Qatar – to be generating budget shortfalls by 2016 as spending continued to gain.

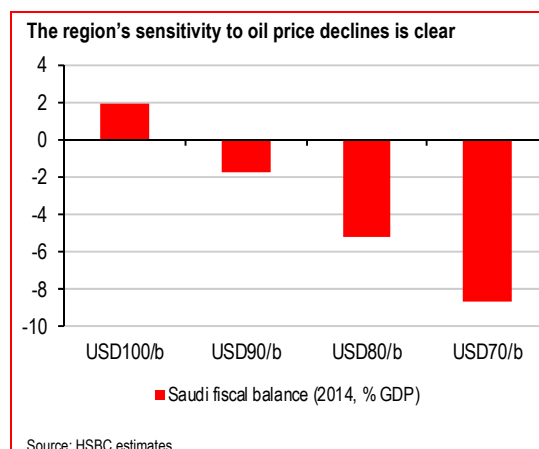
The strength of the leading oil producers' balance sheets would allow them to fund shortfalls that would accrue over the remainder of the decade. We suspect, however, the emergence of budget deficits would likely see spending growth lose pace given the inevitable uncertainty over where prices might settle in the longer term. This in turn would act as a significant brake on overall economic performance.

Game changer

The greater danger for the region is that a more-rapid-than-anticipated expansion of non-conventional energy supplies – or technical innovation that allows gas to act as a better substitute as a transport fuel – leads to a marked fall in crude oil demand, drawing prices down with it. The impact would, inevitably, be more profound still if changes in the global energy markets were to be compounded by sustained period of sub-par global economic growth.

As we have argued elsewhere (see [Oil Rich Outperformers](#), July 2013) an oil price that settled below USD90/bbl would require Gulf governments to rethink their spending plans. An oil price below USD80/bbl, meanwhile, would generate wholesale budget shortfalls of a scale that would necessitate not just a slowdown in spending growth, but sharp cuts in budget outlays, curtailing the capacity of the state to deliver welfare and other services that are at the core of the political economy.

Spending cuts would also weigh very heavily on overall economic growth and employment generation – an enormous concern for a region with an overwhelmingly young and fast-growing population and a history of political turmoil. Steep oil price falls that eroded the Middle East's current account surpluses would also start to raise questions over the stability of regional currencies, as well as undermine their currently robust risk ratings, compromising their access to external funding.



It is possible that with time, a sharp drop in equilibrium oil prices could accelerate stalled economic reform and finally trigger the shift away from a reliance on hydrocarbons that policy makers have long promised. The transition would prove challenging, however, and tumultuous for a region which has based its economy so solidly for so long on the rent it has been able to generate from its conventional oil deposits.

Developing non-conventional oil

At the margins, the region has shown some appetite for developing its own non-conventional energy resources. Rapid growth in domestic energy demand has put growing pressure on available conventional gas resources. This has raised doubt over economic growth targets and high profile industrialisation plans, even in energy-rich states such as Saudi Arabia and the UAE. Indeed, both states project rapid growth in energy demand, but already forgo export receipts by burning liquids to meet peak energy demand, and the UAE has been required to build a pipeline to Qatar to offset its rising gas demand. In North Africa, meanwhile, the well-developed gas export infrastructure with pipelines to Europe offer scope to exploit significant shale-gas reserves, which, according to the EIA, are among the highest in the world in Algeria.

The abundance of the region's conventional hydrocarbon resources, however, and the low cost of production, have created little incentive in the past for developing shale resources, leaving the Middle East lagging peers elsewhere. The ownership norms in the region – hydrocarbon resources have been the property of the state since nationalization in the 1970s and are exploited overwhelmingly by firms in which the state has total or majority ownership – have also left no scope for the private sector to step in.

Despite gains in technology, extracting non-conventional oil from remote desert locations, where transport links and water supplies are limited, is costly and difficult to effect. Indeed, the region has sought to address rising energy demand by developing renewable resources, including nuclear power, with the UAE now in the process of developing the Gulf region's first reactor. Underscoring the limited commercial value that the resources are seen as having, much of the region's non-conventional resources have not been fully surveyed and explored.

Poland

- ▶ The size of Poland's recoverable unconventional and shale gas resources is highly uncertain, and estimates are widely divergent
- ▶ Exploration licenses have already been issued, but progress on drilling has so far been slower than expected
- ▶ As 80% of Polish gas is imported from Russia, the Polish government is keen to develop domestic gas sources

The lure of shale gas

Big – but just how big?

There is big potential for shale gas in Poland but the size of the recoverable unconventional gas resources is uncertain. Estimates differ widely and are mostly based on historical data or comparisons between geological formations there and in the US, although the US experience may not be relevant to Poland.

In 2009, the Wood MacKenzie company estimated recoverable shale gas resources at 1.4trn cu m. At

the same time, the Advanced Research Institute estimated recoverable unconventional gas resources at 3trn cu m. Rystad Energy's 2010 study estimated them at 1trn cu m and in 2011 the US Energy Information Agency and the Advanced Research Institute identified Poland as having the highest shale gas potential in Europe. These findings fueled expectations of a bright gas exploration future for Poland and attracted interest from mining and exploration companies, including key world players such as Chevron and Exxon Mobile.

Agata Urbanska
Economist
HSBC Bank plc
+44 20 7992 2774
agata.urbanska@hsbcib.com

Recoverable shale gas potential, trn cubic meters

Country	Resources
China	36.1
US	24.4
Argentina	21.9
Mexico	19.3
South Africa	13.7
Australia	11.2
Canada	11
Libya	8.2
Algeria	6.5
Brazil	6.4
Poland	5.29
France	5.09
Norway	2.35
Ukraine	1.19
Sweden	1.16
Total	173.78

Source: US Energy Information Agency

But in March 2012, the Polish Geological Institute presented much smaller estimates of recoverable unconventional gas reserves. These put the resource volume at a maximum of just 1.92trn cu m and possibly only 38bn cu m. The most probable scenario estimated recoverable gas resources at 346-768bn cu m. Though much lower, that would still be 2.5-5.5 times higher than already documented conventional resources and could cover 25-55 years of domestic gas use, based on 2011 consumption (or 17-38 years based on estimated 2030 usage).

However, there is a low confidence level to all these estimates. The Polish Geological Institute's numbers were based on archival data from just 39 drilling holes, which were prepared and published between 1950 and 1990.

Poland's "shale belt" covers 37,000sq km – 12% of the country – and stretches from the Pomeranian Basin on the Baltic through central Poland and the Podlachia Basin to the Lublin Basin in the east. The most promising zone is the area crossing Poland from Central Pomerania to the Lublin Voivodship.

The first licenses for hydrocarbon exploration from unconventional sources were issued in Poland in 2007, and numerous applications from Polish and foreign companies followed in 2010 and 2011 on the back of early high reserve estimates.

As of March 2013, some 109 licenses had been issued for shale gas exploration and two for tight gas exploration. All the biggest Polish companies in the energy market hold licenses, including Polskie Górnictwo Naftowe i Gazownictwo S.A. (PGNiG S.A.), PKN ORLEN S.A., and LOTOS S.A. Group. PGNiG, the state-controlled miner, holds 95 licenses for hydrocarbon deposits exploration, 16 of which cover exploration and production of both conventional and unconventional hydrocarbons. PGNiG is also

involved in natural gas and crude oil E&P in Norway, Libya, Pakistan, the Czech Republic, Denmark and Germany. At present, that involvement abroad is a more important component of Poland's resource diversification plan than the development of domestic shale gas.

Numerous international players are also operating in Poland, including Chevron, one of the six largest global fuel companies, which holds four licenses for shale gas exploration. However, following the announcement of the revised resources estimates and disappointing first drilling results, ExxonMobil Corporation withdrew from Poland in June 2012, followed by Marathon Oil Corporation in spring 2013. Talisman Energy Inc. is also considering withdrawal. High expected exploration costs and uncertainty about the legal environment – including future licensing and the taxation policy – contributed to those decisions.

By March 2013, some 42 exploration holes had been drilled and fracturing tests had been performed in nine of them, although the results are not publicly available. This compares to expectations in early 2012 of 72 drilling holes by the end of 2012. The licenses granted by 30 April 2012 involve the obligatory drilling of 123 holes and 110 optional drillings by 2017.

Poland needs to reduce its dependency on Russia gas

Poland consumed about 14bn cu m of natural gas (high-methane equivalent) in 2011. It produces some 30% of consumption and imports the rest. The National Geological Institute put Poland's natural conventional gas reserves at 140-145bn cu m (94bn to 98bn cu m in high-methane equivalent) at the end of 2011, which equates to roughly 23 years' supply of domestic resources at the current consumption rate.

Industry is the main consumer of gas (60%), followed by households (27%) and services

(12-16%). Power generation absorbs only 17%, however. Other industrial uses mostly relate to chemicals, especially fertilizers.

The Ministry of Economy forecasts that gas consumption will increase more than 40% by 2030, mostly because of a 150% rise in power production, although it also expects trade use to more than double and transport consumption to rise more than 50%. Poland's power-generation sector has historically been heavily reliant on coal because of available domestic coal resources; however, increasing production costs and European climate targets are expected to increase gas's share in electricity production. Changes in power generation will therefore be the key determinant of Polish demand for gas.

Some 80% of gas is imported from Russia. Existing transport channels, centered on east-west trade, largely determine the supply but given unease about this high dependency, Poland's strategy for the years ahead is to diversify. New transport channels with EU countries are being established, including the Lasow connection, which has flow capacity of 1.5bn cu m, to bring gas from the west, and the Cieszyn link, with the Czech gas network, to bring gas from the south. Poland also agreed with Russia in 2010 to reverse the flow of the Jamal pipe, allowing up to 2.5bn cu m of gas imports to flow from the West. Some 800m cu m was bought using this reverse flow capacity in 2012. And in 2014, a new LPG terminal will open, with expected annual capacity of 5bn cu m: state-controlled PGNiG has signed a 20-year agreement for Qatargas to deliver 1.5bn cu m a year.

Russian gas is supplied under a long-term contract signed in 1993. The latest amendment, in October 2010, limits Poland to a maximum supply of 10.2bn cu m per year until 2022.

Diversification into nuclear and renewable energy

The reliance on imports and the concentration of sources has raised concerns about Poland's energy security. These were addressed in the government's policy document, Energy Policy of Poland until 2030, agreed in November 2009. The objectives set were: improved energy efficiency; diversification of power production technology; more varied sources of energy – including the introduction of nuclear, renewable energy sources, and biofuels; and reducing the power industry's environmental impact to conform with the EU's plans for 2020 – the so-called “3x20%.”

Nuclear energy is the key policy change in the power production balance. Its share of energy output is forecast to increase from nothing in 2010 to 15% in 2030, and it would replace coal. As a result, brown coal's share of power production would fall from 35% to 21%, and hard coal's share, from 53% to 36%. Gas's share in energy production would double, albeit from a low level, rising from 3.4% in 2010 to 6.6% in 2030. However, successful shale gas production would critically change those assumptions.

Conclusion: A lottery ticket

The Polish government is keen to develop shale gas production. Its ongoing exploratory drillings make it the European country that has advanced furthest in exploring the potential of shale gas – which is consistent with estimates that Poland could have the highest unconventional gas resources in Europe. However, it is still uncertain, for now, whether there really are sizable recoverable shale gas deposits in Poland, how technically challenging exploration might be, and how costly/profitable it would be.

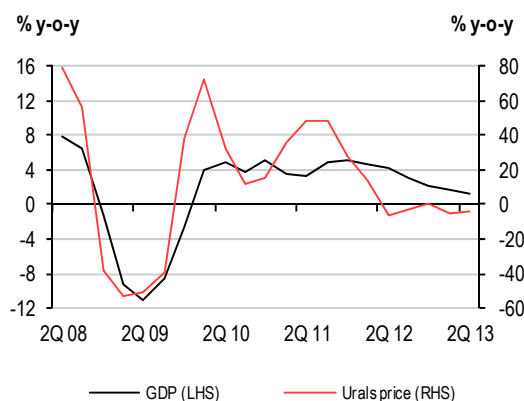
Russia

- ▶ Russia's economy remains dependent on oil prices
- ▶ Shale oil and gas present Russia with both opportunities and threats
- ▶ Most risks are medium term in nature, while opportunities are only likely to materialize in the long term

Role of energy in the Russian economy

The Russian economy is heavily reliant on energy, especially exports of hydrocarbons (crude oil, oil products, and natural gas). While the share of hydrocarbons in the economy is relatively small, at about 20-25% of GDP, they account for about 66% of Russian exports.

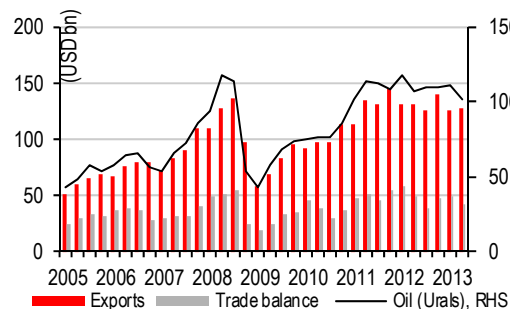
Russia's economic growth depends on the oil price



Source: Rosstat, HSBC

As a result, oil and gas price fluctuations are strongly echoed by swings in Russia's exports and balance of payments. A USD10/bbl decline in oil prices results in a fall of around USD30bn in annual exports of oil and natural gas (1.5% of GDP).

Russia's exports follow oil prices

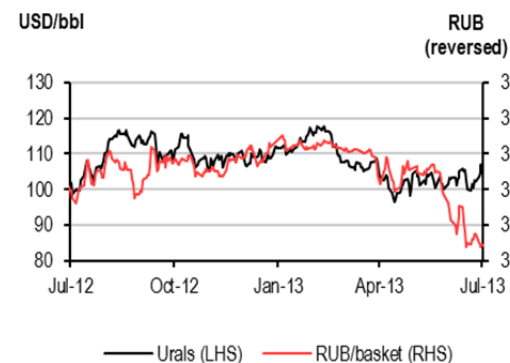


Source: CBR, MOED

Alexander Morozov
Economist
OOO HSBC Bank (RR)
(Limited Liability Company)
+7 495 783 8855
alexander.morozov@hsbc.com

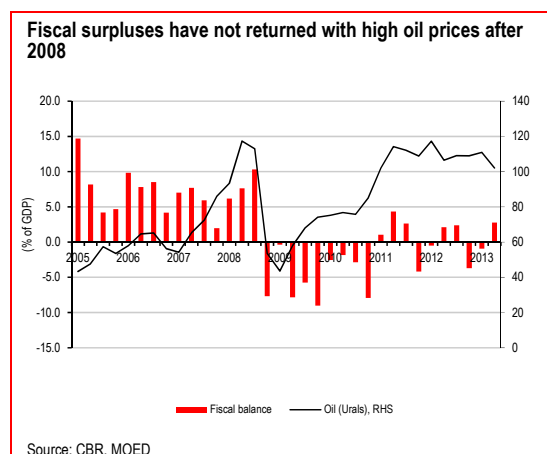
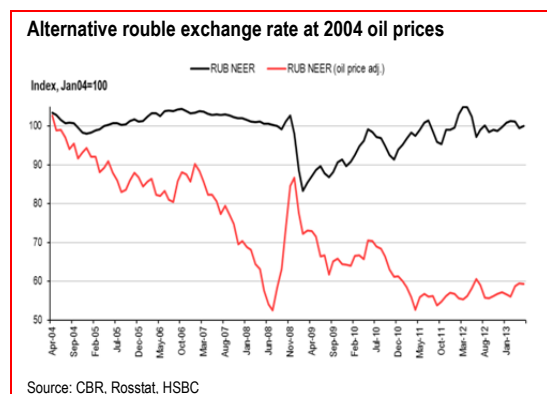
This makes both the rouble and the Russian stock market highly vulnerable to energy price moves too. Indeed, oil prices (Brent) are the single most influential factor for the currency and equities in

Oil prices and the rouble



Source: CBR, ThomsonReuters Datastream

Russia. We estimate the oil price elasticity of the rouble real effective exchange rate at 0.29-0.34.



Oil and gas revenues also constitute roughly half of federal government revenues in Russia. The marginal tax rate (including that on oil and gas exports) is about 90% at high oil prices, so oil price fluctuations also have a strong impact on Russia's budget.

It follows that any significant movements in the global energy market would resonate strongly in Russia, both economically and politically.

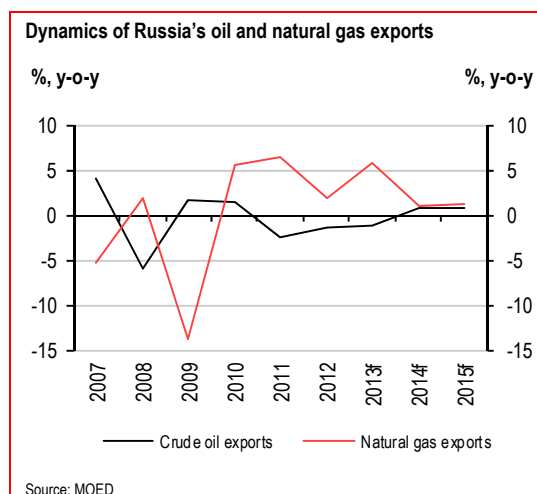
Energy balance of trade

Russia produced 517mt of crude oil in 2012, of which 378mt were exported to European and Asian markets. This includes oil products, which are gradually capturing a bigger share in exports from crude oil due to preferential taxation of these exports. Russia produced 653bn cu m of natural

gas in 2012 and exported 179bn cu m, predominantly to Europe. In this respect, natural gas production is much more oriented towards domestic consumption than oil production.

Russian officials do not expect any significant changes in oil and gas output and exports volumes in the medium term. The Ministry of Economic Development (MOED) forecasts both crude oil output and exports to be flat vs 2012 in 2016, with oil product exports falling to 128.2mt in 2016 from 138mt in 2012 due to rising domestic demand. The MOED also expects LNG exports to be flat at 10mt throughout the 2013-16 period. At the same time, it foresees natural gas output and exports growing modestly to 690bn cu m and 190bn cu m, respectively, in 2016, from 653bn cu m and 179bn cu m, respectively, in 2012.

Effectively, this scenario is close to status quo for the energy trade in Russia, with benefits or losses for trade coming predominantly from changes in export prices. As a result, Russia's share in global liquid hydrocarbon production is set to decline to 11.0% by 2016 from 11.6% in 2012, according to the MOED. Moreover, its share in global natural gas production is projected to decrease to 19.0% from 19.3% over the same period.



Long-term prospects: Gravitating eastwards

Our recent research has found that the trend of foreign trade gravitating eastwards will likely continue, with Asia (led by China) becoming Russia's key trade partner and surpassing Europe by 2050 (see HSBC: [CIS trade report: gravitating eastwards](#), 8 July 2013). Russian energy trade has also been gravitating eastwards and will most likely continue to do so in the future.

Over the past two decades, Russia has developed oil and gas projects in Sakhalin, in the Far East of the country, which included the construction of an LNG plant and terminal. Oil and gas from Sakhalin is shipped to Asian markets. Recently, Russia has also completed construction of the East Siberian & Pacific Ocean (ESPO) oil pipeline, and started crude oil shipments to China, as well as to other countries in the region. ESPO crude oil has become one of regional benchmarks for oil prices and is priced at a premium to both Brent and Russian Urals. In June Russian-state-controlled Rosneft agreed on the conditions for a long-term contract with China, under which the company pledged to supply 12mt annually to China in return for multi-billion pre-financing. This would require further expansion of the ESPO oil pipeline.

The flat crude export volumes projected by the MOED in the medium term imply that Russia will be reducing its crude oil supplies to Europe, but increasing supplies to the premium markets in China and Asia.

Russian-state-controlled Gazprom, which has a monopoly on gas pipelines and has been granted monopoly rights to export natural gas, also has plans to develop its business in Eastern Russia and start supplying natural gas to Asian markets, in addition to the LNG project in Sakhalin, in which it has a share. In this respect, Gazprom has

advanced in negotiations with its Chinese counterparts for natural gas supplies via a new gas pipeline to China. Gazprom owns the large new Kovykta natural gas field in Eastern Siberia, which can be developed to provide gas for exports to China and, potentially, to other Asian markets. In addition to Gazprom, some Russian oil companies are considering building LNG plants in Far East Russia to provide LNG supplies to growing Asian markets.

At the same time, Gazprom's export positions in Europe have weakened. The recession in the eurozone, increased competition from the LNG spot market, cheap coal, and the more flexible pricing policy adopted by some competitors reduced Gazprom's natural gas exports to Europe in 2012 and eroded its share in the total natural gas consumption of that region.

It follows that, in the case of natural gas, increasing supplies to China and the Asian region could be sourced from new natural gas resources in the Eastern part of Russia rather than diverting gas supplies to Europe, where Gazprom has to adopt a more flexible approach to changes in the European natural gas market in order to sustain its supplies.

Shale (r)evolution: Opportunities and threats

Irrespective of whether we define shale as a revolution or evolution in the natural gas and crude oil industry, it undoubtedly has important implications globally. How is Russia positioned in this context? While it tops the list of countries with the highest reserves of natural gas and is at the top in terms of the amount of its oil reserves, it also has plentiful shale oil and shale gas reserves. Consequently, the shale oil and gas evolution (or revolution) should benefit Russia, as one of the largest exporters of hydrocarbons.

However, these benefits are most likely achievable only in the long term. At current technological levels, the extraction of shale gas and shale oil will entail production costs higher than those of traditional hydrocarbons. This is especially significant for shale gas, as known new traditional gas fields can supply enough cheaper natural gas to meet both domestic and export demand for years.

The situation with shale oil is similar, but more complicated: the large Bazhenov shale oil field is located in Western Siberia, which is more geographically convenient and has more developed infrastructure than the remote new traditional oil fields of Eastern Siberia and the Arctic sea shelf. Moreover, state-controlled Rosneft has a monopoly right to develop oil fields on the Russian sea shelf, which forces other oil companies to look elsewhere for investment opportunities. However, geological conditions in the Bazhenov oil field are different than those in the Bakken formation, in the US. Put simply, this means that technologies for the extraction of shale oil that are successfully used in the US do not work in Russian Bazhenov oil field. It will probably take a few years for appropriate technologies become available.

Taxes also matter. Assuming a cost of USD5-10m per single well in Russia, Wood Mackenzie estimated the break-even oil price for oil from the Bazhenov field at USD50-86/bbl at present. Adding taxes on top, the break-even oil price would rise to USD99-188/bbl. This would most likely exceed current oil prices, discouraging investment in shale oil in Russia – even if an economically efficient technology tailored to the geological peculiarities of Bazhenov were developed. The current tax regime in Russia therefore makes shale oil less attractive to investors than the Eastern Siberian and shelf oil fields, which enjoy reduced taxes as an incentive

for their development. The Russian government is considering creating a favorable tax regime for shale oil deposits, so we could see the tax considerations that currently hinder the development of shale oil in Russia, soon removed.

The above indicates that the development of shale oil is only likely be given a boost in Russia if:

- (1) further technological advances significantly reduce the costs of shale oil extraction ; and
- (2) shale oil fields are granted tax exemptions similar to those extended to the traditional oil fields in Eastern Siberian and the Arctic shelf. It therefore follows that Russia can only reap the benefits of its rich shale oil and gas reserves in the long term.

In the medium term, the country's oil and gas producers will face challenges from rising production of shale gas and oil in other parts of the globe and the resultant competition – primarily from the US. The negative impact is most likely to manifest itself in lower prices rather than lower exports. The situation for natural gas production is even more complicated. In addition to suffering negative price effects, gas export volumes may decline unless the price policies of Gazprom – the monopolistic Russian gas exporter – become more flexible, allowing it to respond more rapidly to competition from other producers of conventional natural gas, LNG, or shale gas.

According to a study conducted by the Institute of Energy Research of the Russian Academy of Sciences (IER RAS), the negative oil price impact from shale oil is only likely to become permanent if shale oil technology advances further – especially with respect to water use intensity. Even in that case, though, technological advances will likely be consistent with only a moderate decline in oil prices to USD80-100/bbl, in constant 2012 USD terms, by 2030.

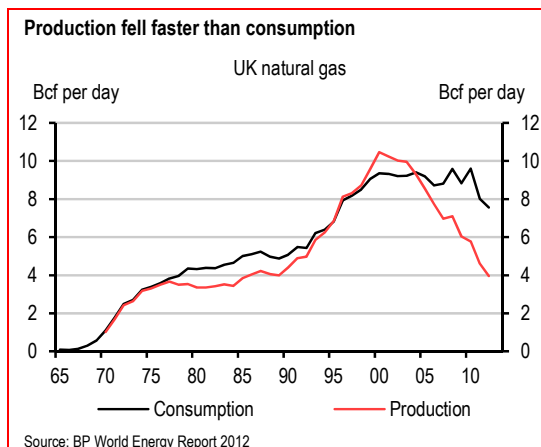
UK

- ▶ The government hopes that shale gas can benefit the UK and help offset the structural decline in North Sea oil and gas output
- ▶ Estimates of recoverable gas are wide and hugely uncertain so it could take decades for any meaningful production
- ▶ The UK faces significant technological and geological hurdles, as well as a skeptical public and vocal protesters

Not much more offshore

North Sea output in structural decline

UK oil and gas extraction is in structural decline. The flow of North Sea oil, which began in 1975, peaked in 1999. UK output of oil and gas in 2012 was around 33% below the peak levels. Over the next few years, the pace of decline may fall and even reverse slightly as recent investments start to pay off and new oilfields come into production. Investment remains high with industry bodies predicting a record GBP13.5bn level of nominal investment in 2013.



Weighing on GDP and trade balance

Nevertheless, the structural trend is clear. Since 2000, the decline in oil and gas extraction has subtracted an average of 0.25pp from annual GDP growth. Meanwhile, imports of oil and gas have risen while exports have fallen. If the UK is to reverse these negative impacts on output and trade, domestic energy alternatives must be found.

The long trail to shale

All talk and no action

Judging by the heated debate between groups for and against fracking, one would be forgiven for thinking that the UK is on the cusp of an energy revolution. Prime Minister Cameron believes shale gas could help increase productivity and reduce energy prices. Opponents cite potential pollution and damage to the British countryside.

The fact is that estimates of the potentially recoverable shale energy are highly uncertain and only a handful has so far been drilled in the UK. And even if the UK does eventually see significant shale energy production, it is likely to be at least a decade away.

Simon Wells
Chief UK Economist
HSBC Bank plc
+44 20 7991 6718
simon.wells@hsbcib.com

Great deal of uncertainty regarding quantity of shale gas resources

	British Geological Survey*	US Energy Information Administration	
Trillion cubic feet	Bowland Shale (only)	Total UK: unrisks	Total UK: risks ³
Total resources (GIP)	1329 ¹	623	134
Technically recoverable resources (TRR)	64-460 ²	na	26

N.B. BGS and EIA estimates are not comparable since they measure different regions.

1. BGS central projection.

2. TRR potential estimate is found by extrapolating BGS total resources estimate using North American recovery factor of 8 – 20%. See Dr A. Goater (UK Parliament), "UK Shale Gas Potential", July 2013.

3. Risks estimates adjust initial total resources estimates in order to take account of knowledge limitations concerning the shale formation and known formation-specific factors that may limit sections of the prospective area from development (e.g. geologic complexity).

Onshore is not sure

The British Geological Survey (BGS) estimates that the UK could be sitting on 1,329trn cubic feet (tcf) of shale gas in the Bowland Basin alone. With annual UK gas consumption of 2.8tcf² currently, figures like this suggest the UK could have its own energy revolution. In monetary terms, 1,329tcf is worth around GBP8trn at current prices³ or 600%⁴ of UK GDP.

However, extrapolating the BGS total resource estimate using US recovery rates of 8-20% yields technically recoverable resources of only 64-460tcf (regardless of whether it is economically viable to do so). This is considerably smaller than the BGS estimate, but would still be a significant amount, able to supply the UK for at least 20 years at the current rate of consumption.

Other estimates are less favorable. The US Energy Information Agency (EIA) estimates UK-wide total resources of 623tcf. But when this is risk-adjusted to take account of limitations in the knowledge of shale formation and known geological complexities (something the BGS's estimates do not do), the EIA's estimate falls to just 26tcf. While this still amounts to nine years of UK gas consumption (at current levels), it falls well short of the energy revolution suggested by 1,329tcf.

Compared to other European countries, the EIA's estimates point to the UK having relatively modest amounts of recoverable shale gas. Of course, all of these estimates are subject to considerable uncertainty.

Actually recoverable reserves may not be that high

Risks technically recoverable resources (tcf)	
Russia	285
Poland	148
France	137
Ukraine	128
UK	26

Source: US Energy Information Administration

Even if total shale gas resources end up being towards the upper end of current estimates, and assuming it is technically and economically recoverable, it would take time for the benefits to materialize. One think-tank assumes 1-2 years for exploration and evaluation plus another 10 years to drill the wells and build the infrastructure for material production. Add to this another 1-2 years to secure developmental and environmental approvals, and it could be 10-15 years before UK shale starts to flow.

Fracking difficult

A successful shale gas operation requires good access to shale areas, a water supply, and road and pipeline infrastructure. Even then, technology must be optimized for the specific area and the flow rate must be favorable. As UK shale exploration is a step into the unknown, there are huge uncertainties regarding whether existing technologies can be

² Oxford Institute for Energy Studies.

³ Average August dollar price divided by average August exchange rate (9.58/1.58).

⁴ GBP6.1bn/1.5trn (2012 GDP).

adapted to UK geology on top of the uncertainty about the size of viable reserves.

In the UK, shale sites are thought to be smaller and deeper in ground than in the US, which makes fracking more difficult. With only two exploratory wells having been drilled in the UK so far, there is limited hard data.

The regulatory environment may also restrict UK shale gas development relative to the US. UK regulations regarding groundwater pollution are considered to be stricter, and as the industry is in its infancy, there is a significant degree of regulatory uncertainty.

Finally, a supportive fiscal regime is necessary for a successful shale gas industry. As announced in the 2013 budget, the British government is consulting on the tax regime and is proposing to exempt a proportion of shale production from supplementary charges. This allowance would roughly halve the effective tax rate for the exempted portion of production, which in turn would be related to the capital expenditure incurred. The precise details have yet to be published.

A wary British public

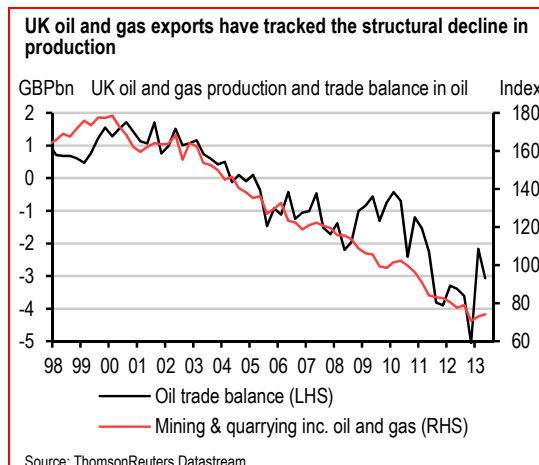
Another unpredictable factor is the response of the British public. Recently, anti-fracking protesters have become more vocal, and the UK has a tradition of disrupting projects where there are environmental concerns (e.g. large protests against high-profile road building in the 1990s).

Whether the environmental concerns can be addressed or not, one problem with shale gas could be the sheer number of wells that would need to be drilled around a site to make production viable. For instance, some successful US projects, such as the Barnett shale site, have required 16,000 wells in 21,000sq km. The proximity of some UK shale gas reserves to

densely populated urban areas could make a similar intensity of drilling impossible.

Economic impact

One key issue is that the direct economic benefits will take a long time, if ever, to materialize. But assuming production does happen, that could boost GDP, net exports, and public finances. For example, the structural declines in oil and gas exports have contributed to the large current account deficits that the UK has been running in recent years. But it is unlikely to single-handedly bring the UK back into a trade surplus, and in the short run, may even increase the size of the trade deficit due to the significant amount of investment required (and thus imports).



Of course, the indirect benefits could be felt before that, as significant investment would need to be made. A single test well operation costs about GBP10.5m⁵. It has been estimated that at least 300 wells would need to be drilled per year for 10 years for production capacity to reach around 10% of current consumption (assuming that current US technology is applicable in the UK). That equals roughly GBP3.15bn of investment per year.

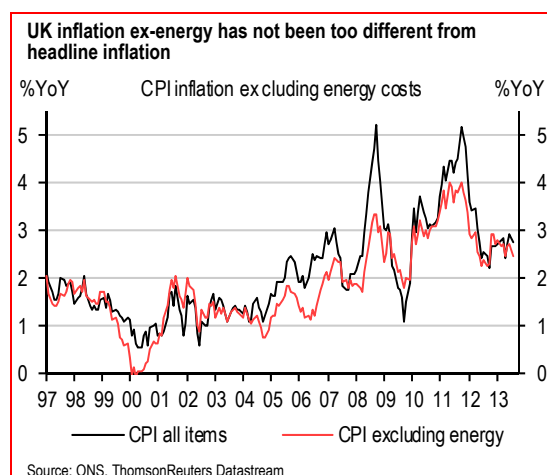
⁵ http://www.cuadrillaresources.com/wp-content/uploads/2012/02/Full_Report_Economic_Impact_of_Shale_Gas_14_Sept.pdf

On top of this, infrastructure investment, notably roads, water pipes, etc, would be needed. And if we assume positive multiplier effects, the overall economic benefit would be higher still.

Prices effects likely to be limited

One argument in favor of shale exploration has been that it could drive down energy prices. But that neglects the fact that the UK is a very open economy, and trade in oil and gas is international. UK gas prices are mainly determined by the global market, of which the UK constituted just 1.4% and 2.5% of production and consumption, respectively, in 2011 (the comparable share for the US is 20% of world production and 21.5% of total consumption).

So the UK is unlikely to move world gas prices. Of course, it could still benefit from lower global prices as a result of the shale revolution in the US. Energy costs (i.e. petrol, electricity, gas) currently account for 9% of the UK CPI. But for data since 1997, the difference between the headline rate of CPI inflation and CPI excluding energy has averaged only 0.2pp.



Conclusion

Although there is an increasingly heated debate about unconventional gas in the UK, our reading of the situation is that there is huge uncertainty about the size of viable reserves and whether the technology exists to extract them. On the most positive assessments – assuming the British public can be persuaded to embrace shale gas – the UK could completely meet its natural gas needs for 20 years. On pessimistic estimates of recoverable resources – and if the public is resistant to development, which could increase costs further – the economic benefits could be negligible.

In short, there is currently too much uncertainty: the commercially viable UK shale gas reserves could be substantial, or they could be zero.

Venezuela

- ▶ Venezuela has huge oil reserves, but the case for an aggressive expansion in oil output is hindered by the institutional framework
- ▶ Development of the Orinoco oil belt is likely to be held back by financing constraints
- ▶ The country's economic prospects are intimately linked to the expansion of the oil sector

Financing constraints rein in Venezuela's oil ambitions

Venezuela is a major player in the global oil market, being one of the largest exporters of crude oil globally and the biggest in the Western Hemisphere. Oil and gas accounted for 75% of the country's total energy consumption in 2010, with the remainder mostly supplied by hydroelectric power.

Over the past decade, the share of oil consumption has risen steadily, from 36% to 47%, driven by the Chávez administration's heavy subsidization of liquid fuels. The energy trade balance has traditionally been largely positive owing to the

huge oil trade surplus. In 2012, the fob oil trade balance stood at USD81.7bn, or 18.4% of GDP.

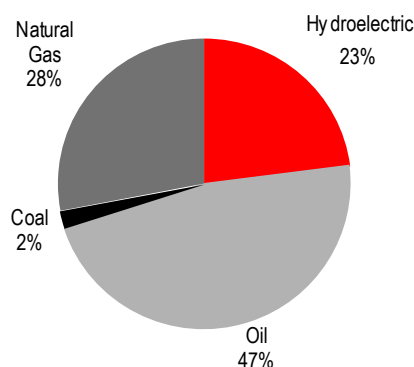
The oil sector

The oil industry stands at the very center of Venezuela's economic landscape, accounting for 96% of the country's export revenues. This lack of diversification makes Venezuela extremely vulnerable to swings in the oil market.

According to estimates put together by local consultant Síntesis Financiera, total oil production averaged 2.8 million barrels per day (mbd) in 2012, while domestic consumption stood at 0.76mbd. Estimates of Venezuelan production vary from source to source, partly due to differences in

Ramiro Blazquez
Economist
HSBC Bank Argentina S.A.
+54 11 4348 2616
ramiro.blazquez@hsbc.com.ar

Total energy consumption (2010)



Source: U.S.EIA, HSBC

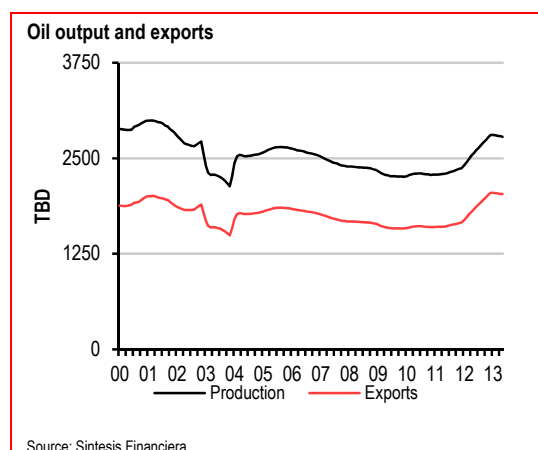
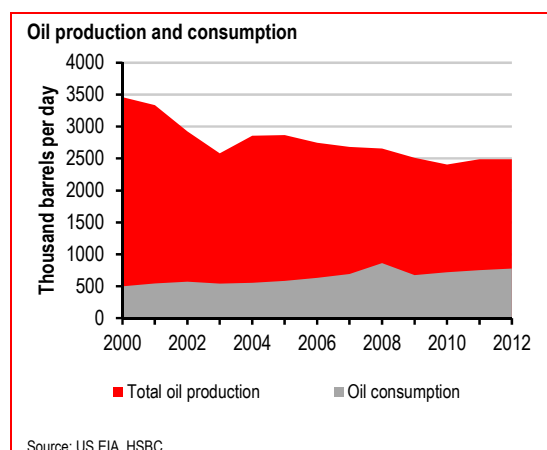
measurement methodology; some sources – notably the US Energy Information Administration (EIA) – categorize extra-heavy oil produced in the Orinoco Belt under a different category. Sintesis Financiera's estimates are the average of figures from several sources, including the Ministry for Oil and Energy, the International Energy Agency (IEA), and OPEC. It is important to highlight that production is currently below 2001 levels and has been trending downwards ever since the late president, Hugo Chávez, first took office in 1999. Output levels for 2012 were around 13% below 1999 production figures. However, export volumes showed an accumulated increase of 8.4% over the same period.

During the 1970s, Venezuela nationalized its oil industry, with the creation of *Petróleos de Venezuela S.A. (PdVSA)*. Attempts to liberalize the oil sector in the 1990s were reversed during the following decade under the Chávez administration, which sought to increase public participation in the industry. The Chávez government levied tax and royalty contributions on new and existing projects, and mandated that PdVSA must have majority ownership of all oil projects. In 2002, a major labor strike in the oil sector brought oil output to a standstill, prompting the government to dismiss 18,000 PdVSA employees and restructure the company in order to strengthen government control. In 2007, President Chávez mandated the nationalization of

oil exploration and production, ensuring that PdVSA would hold a minimum 60% share in both new and existing projects.

The Oil and Gas Journal (OGJ) estimated that Venezuela had 211bn barrels of proven oil reserves in 2011 – the second-highest level in the world and up from 99.4bn only two years previously. The difference came from the inclusion of vast reserves of extra-heavy oil located in the Orinoco Belt, and actual reserves could prove to be even bigger – as much as 316bn barrels, according to PdVSA. This is currently under investigation as part of the “Magna Reserva” project launched by PdVSA in 2005.

Venezuela has billions of barrels of extra-heavy crude oil and bitumen deposits located in the Orinoco Belt in the center of the country. According to a study released by the US Geological Survey, the mean estimate of recoverable oil resources from the Orinoco Belt is 513 barrels of crude oil. In its Magna Reserva project, PdVSA divided the Orinoco region into four distinct areas to quantify reserves. The findings to date have allowed for the huge upward revision in certified reserves mentioned in the previous paragraph.



The 2007 nationalization of the oil sector led to the emergence of newly merged companies in which PdVSA held the majority stakes. ConocoPhillips and ExxonMobil responded to the situation by leaving the country (and filed a suit against Venezuela with the ICSID), while Total, Chevron, BP, and Statoil remained. More recently, PdVSA has also engaged in partnerships with several Chinese and Russian oil companies. Development of the Orinoco Belt is Venezuela's main strategy for aggressively expanding oil production and foreign exchange inflows to the country. Capital rationing due to depressed business confidence and the pervasive role played by the state has prevented projects from moving forward at a faster pace.

Venezuela is currently the US's fourth-largest supplier of imported crude oil and petroleum products after Canada, Mexico, and Saudi Arabia. However, US imports from Venezuela have gone down in recent years. In 2011, the US imported almost 1.0mbd of crude oil and petroleum products from Venezuela. However, due to geopolitical tensions and the discovery of shale oil in the US, Venezuela's relevance as an oil supplier to the US has been declining in recent years.

The natural gas sector

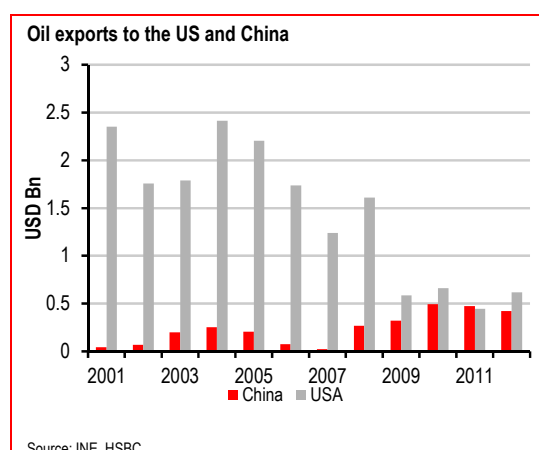
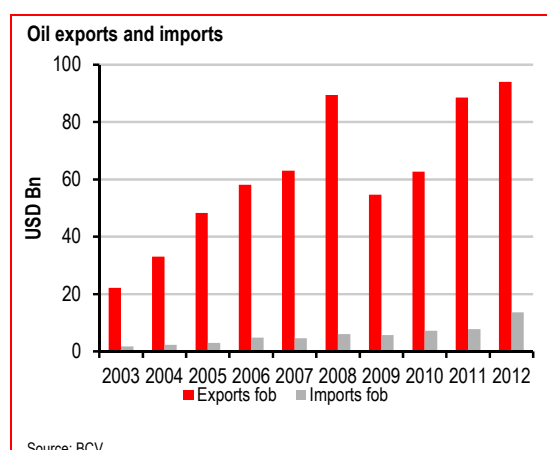
Venezuela's proven natural gas reserves of 195 trillion cubic feet (tcf) in 2012 are the second largest

after the US's. In 2011, Venezuela produced 1.1tcf and consumed almost 1.2tcf of dry natural gas. Natural gas is mostly used by the oil industry for gas re-injection, which helps crude oil extraction. In order to satisfy increasing industrial demand, Venezuela purchases gas from Colombia and the US. PdVSA is the largest producer and distributor of natural gas in Venezuela, followed at some distance by private companies such as Repsol-YPF, Chevron, and Statoil.

Around 90% of Venezuela's natural gas reserves are associated with oil reserves. In 2009, the Energy and Petroleum Ministry announced plans to increase natural gas production to roughly 14bn cubic feet per day (bcf/d) and begin exporting by 2015. Venezuela's government and the oil companies have not disclosed their shale oil or shale gas exploration activities, although the potential in western Venezuela appears to be large and of high quality.

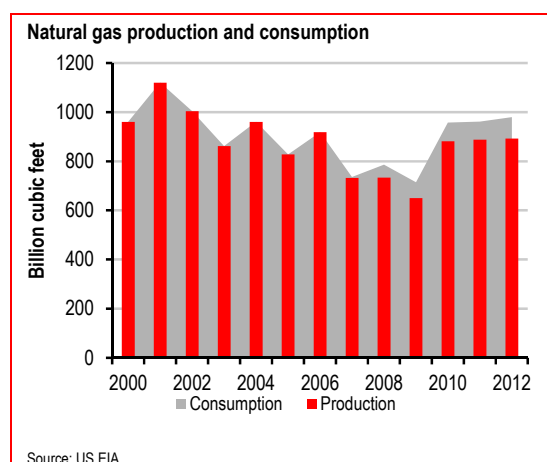
The electricity sector

In 2010, Venezuela had nearly 25 gigawatts of installed generation capacity, 72% of which originated from hydroelectric power. For most of the past decade, power consumption has expanded at more than twice the rate of installed capacity, which has been causing tensions and limiting growth over this period. A major drought in 2009-10 forced President Chávez to declare a



“power emergency,” which led to the implementation of power rationing initiatives and also to heavy investments in the set-up of thermoelectric generation capabilities.

Natural gas powers around one-half of Venezuela’s conventional thermal electricity generation, while fuel oil and diesel power account for the rest. After the drought, the government increasingly began to rely on this source of power generation. PdVSA began generating power for its own consumption in 2010 to manage power-supply risks in the oil production sector. Importantly, the expansion of conventional thermal generation capacity could have a negative impact on Venezuela’s oil exports by causing a sharp increase in domestic consumption.

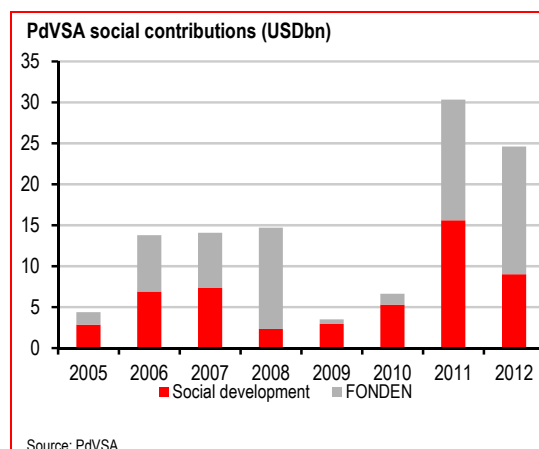


The Orinoco Belt: opportunities and challenges

PdVSA’s Orinoco Belt projects aim to increase oil output by around 50% to 4.2mbd by 2015.

PdVSA’s investment plan is capital intensive, so financing will be one of the main challenges. We are not convinced that the market will be willing to finance PdVSA given prevailing uncertainty about property rights under a *chavista* administration.

Furthermore, PdVSA’s own resources are being diverted away from the company’s core business into areas that are unrelated to the oil industry, and are also being used to finance social expenditure.



In our view, because Maduro’s administration has less popular support than his predecessor, it will need to implement more expansive fiscal policy to finance social projects. With inflation hovering near 40% per annum, non-inflationary sources of financing will have to be sought. The oil industry seems to be the easiest available option for the administration. In order to expand production, PdVSA will likely need to resort to foreign capital and/or rationalize its use of funds in the short run.

We believe the oil output growth trend envisaged by the authorities could be too ambitious in current circumstances. We target an accumulated output expansion of no more than 25% up to 2015.

PdVSA business plan (USDbn)

	2012	2013	2014	2015	2016	2017	2018	2019	Total 2013-19
E&P	12.5	16.9	20.3	23.0	28.5	32.9	34.1	33.4	189.2
PdVSA gas	2.7	1.3	3.5	4.4	4.6	3.0	2.7	2.5	22.0
Refining	2.1	2.7	6.3	5.8	4.4	2.9	1.4	2.2	25.7
Retail and supply	0.72	0.87	0.9	0.9	0.9	0.9	0.9	0.9	6.3
Other	6.6	3.5	1.7	1.7	1.7	1.7	1.7	1.7	13.7
Total	24.6	25.3	32.7	35.8	40.1	41.5	40.9	40.7	257.0

Source: PdVSA

Disclosure appendix

Analyst Certification

Each analyst whose name appears as author of an individual section or individual sections of this report certifies that the views about the subject security(ies) or issuer(s) or any other views or forecasts expressed in the section(s) of which (s)he is author accurately reflect his/her personal views and that no part of his/her compensation was, is or will be directly or indirectly related to the specific recommendation(s) or view(s) contained therein: Kevin Logan, David Phillips, Thomas Hilboldt, Nick Robins, Zoe Knight, Wai-Shin Chan, Jorge Morgenstern, Paul Bloxham, Adam Richardson, Andre Loes, David Watt, Sergio Martin, Lorena Dominguez, Simon Williams, Agata Urbanska-Giner, Alexander Morozov, Simon Wells and Ramiro Blazquez

Important Disclosures

This document has been prepared and is being distributed by the Research Department of HSBC and is intended solely for the clients of HSBC and is not for publication to other persons, whether through the press or by other means.

This document is for information purposes only and it should not be regarded as an offer to sell or as a solicitation of an offer to buy the securities or other investment products mentioned in it and/or to participate in any trading strategy. Advice in this document is general and should not be construed as personal advice, given it has been prepared without taking account of the objectives, financial situation or needs of any particular investor. Accordingly, investors should, before acting on the advice, consider the appropriateness of the advice, having regard to their objectives, financial situation and needs. If necessary, seek professional investment and tax advice.

Certain investment products mentioned in this document may not be eligible for sale in some states or countries, and they may not be suitable for all types of investors. Investors should consult with their HSBC representative regarding the suitability of the investment products mentioned in this document and take into account their specific investment objectives, financial situation or particular needs before making a commitment to purchase investment products.

The value of and the income produced by the investment products mentioned in this document may fluctuate, so that an investor may get back less than originally invested. Certain high-volatility investments can be subject to sudden and large falls in value that could equal or exceed the amount invested. Value and income from investment products may be adversely affected by exchange rates, interest rates, or other factors. Past performance of a particular investment product is not indicative of future results.

HSBC and its affiliates will from time to time sell to and buy from customers the securities/instruments (including derivatives) of companies covered in HSBC Research on a principal or agency basis.

Analysts, economists, and strategists are paid in part by reference to the profitability of HSBC which includes investment banking revenues.

For disclosures in respect of any company mentioned in this report, please see the most recently published report on that company available at www.hsbcnet.com/research.

** HSBC Legal Entities are listed in the Disclaimer below.*

Additional disclosures

- 1 This report is dated as at 22 September 2013.
- 2 HSBC has procedures in place to identify and manage any potential conflicts of interest that arise in connection with its Research business. HSBC's analysts and its other staff who are involved in the preparation and dissemination of Research operate and have a management reporting line independent of HSBC's Investment Banking business. Information Barrier procedures are in place between the Investment Banking and Research businesses to ensure that any confidential and/or price sensitive information is handled in an appropriate manner.

Disclaimer

** Legal entities as at 8 August 2012*

'UAE' HSBC Bank Middle East Limited, Dubai; 'HK' The Hongkong and Shanghai Banking Corporation Limited, Hong Kong; 'TW' HSBC Securities (Taiwan) Corporation Limited; 'CA' HSBC Bank Canada, Toronto; HSBC Bank, Paris Branch; HSBC France; 'DE' HSBC Trinkaus & Burkhardt AG, Düsseldorf; 000 HSBC Bank (RR), Moscow; 'IN' HSBC Securities and Capital Markets (India) Private Limited, Mumbai; 'JP' HSBC Securities (Japan) Limited, Tokyo; 'EG' HSBC Securities Egypt SAE, Cairo; 'CN' HSBC Investment Bank Asia Limited, Beijing Representative Office; The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch; The Hongkong and Shanghai Banking Corporation Limited, Seoul Securities Branch; The Hongkong and Shanghai Banking Corporation Limited, Seoul Branch; HSBC Securities (South Africa) (Pty) Ltd, Johannesburg; HSBC Bank plc, London, Madrid, Milan, Stockholm, Tel Aviv; 'US' HSBC Securities (USA) Inc, New York; HSBC Yatirim Menkul Degerler AS, Istanbul; HSBC México, SA, Institución de Banca Múltiple, Grupo Financiero HSBC; HSBC Bank Brasil SA – Banco Múltiplo; HSBC Bank Australia Limited; HSBC Bank Argentina SA; HSBC Saudi Arabia Limited; The Hongkong and Shanghai Banking Corporation Limited, New Zealand Branch incorporated in Hong Kong SAR

Issuer of report

HSBC Securities (USA) Inc

452 Fifth Avenue, 9th floor

HSBC Tower

New York, NY 10018, USA

Telephone: +1 212 525 5000

Fax: +1 212 525 0354

Website: www.research.hsbc.com

This material was prepared and is being distributed by HSBC Securities (USA) Inc., ("HSI") a member of the HSBC Group, the NYSE and FINRA. This material is for the information of clients of HSI and is not for publication to other persons, whether through the press or by other means. It is based on information from sources, which HSI believes to be reliable but it is not guaranteed as to the accuracy or completeness. This material is not, and should not be construed as, an offer or the solicitation of an offer to buy or sell any securities. The opinions contained within the report are based upon publicly available information at the time of publication and are subject to change without notice. HSI and/or its affiliated companies will buy or sell from customers on a principal basis the securities of the issuer(s) whose securities are recommended in this report. Employees of HSI and its affiliates not involved in the preparation of this report may have positions in the securities mentioned in this report and may from time to time add or dispose of any such securities in a manner different than discussed in this report. Past performance is not necessarily a guide to future performance. The value of any investment or income may go down as well as up and you may not get back the full amount invested. Where an investment is denominated in a currency other than the local currency of the recipient of the research report, changes in the exchange rates may have an adverse effect on the value, price or income of that investment. In case of investments for which there is no recognised market it may be difficult for investors to sell their investments or to obtain reliable information about its value or the extent of the risk to which it is exposed. In the UK this report may only be distributed to persons of a kind described in Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005. The protections afforded by the UK regulatory regime are available only to those dealing with a representative of HSBC Bank plc in the UK. In Singapore, this publication is distributed by The Hongkong and Shanghai Banking Corporation Limited, Singapore Branch for the general information of institutional investors or other persons specified in Sections 274 and 304 of the Securities and Futures Act (Chapter 289) ("SFA") and accredited investors and other persons in accordance with the conditions specified in Sections 275 and 305 of the SFA. This publication is not a prospectus as defined in the SFA. It may not be further distributed in whole or in part for any purpose. The Hongkong and Shanghai Banking Corporation Limited Singapore Branch is regulated by the Monetary Authority of Singapore. Recipients in Singapore should contact a "Hongkong and Shanghai Banking Corporation Limited, Singapore Branch" representative in respect of any matters arising from, or in connection with this report. In Hong Kong, this document has been distributed by The Hongkong and Shanghai Banking Corporation Limited in the conduct of its Hong Kong regulated business for the information of its institutional and professional customers; it is not intended for and should not be distributed to retail customers in Hong Kong. The Hongkong and Shanghai Banking Corporation Limited makes no representations that the products or services mentioned in this document are available to persons in Hong Kong or are necessarily suitable for any particular person or appropriate in accordance with local law. All inquiries by such recipients must be directed to The Hongkong and Shanghai Banking Corporation Limited. In Korea, this publication is distributed by either The Hongkong and Shanghai Banking Corporation Limited, Seoul Securities Branch ("HBAP SLS") or The Hongkong and Shanghai Banking Corporation Limited, Seoul Branch ("HBAP SEL") for the general information of professional investors specified in Article 9 of the Financial Investment Services and Capital Markets Act ("FSCMA"). This publication is not a prospectus as defined in the FSCMA. It may not be further distributed in whole or in part for any purpose. Both HBAP SLS and HBAP SEL are regulated by the Financial Services Commission and the Financial Supervisory Service of Korea. In Australia, this publication has been distributed by The Hongkong and Shanghai Banking Corporation Limited (ABN 65 117 925 970, AFSL 301737) for the general information of its "wholesale" customers (as defined in the Corporations Act 2001). Where distributed to retail customers, this research is distributed by HSBC Bank Australia Limited (AFSL No. 232595). These respective entities make no representations that the products or services mentioned in this document are available to persons in Australia or are necessarily suitable for any particular person or appropriate in accordance with local law. No consideration has been given to the particular investment objectives, financial situation or particular needs of any recipient. This publication is distributed in New Zealand by The Hongkong and Shanghai Banking Corporation Limited, New Zealand Branch incorporated in Hong Kong SAR. In Canada, this document has been distributed by HSBC Bank Canada and/or its affiliates. Where this document contains market updates/overviews, or similar materials (collectively deemed "Commentary" in Canada although other affiliate jurisdictions may term "Commentary" as either "macro-research" or "research"), the Commentary is not an offer to sell, or a solicitation of an offer to sell or subscribe for, any financial product or instrument (including, without limitation, any currencies, securities, commodities or other financial instruments).

© Copyright 2013, HSBC Securities (USA) Inc, ALL RIGHTS RESERVED. No part of this publication may be reproduced, stored in a retrieval system, or transmitted, on any form or by any means, electronic, mechanical, photocopying, recording, or otherwise, without the prior written permission of HSBC Securities (USA) Inc. MICA (P) 118/04/2013, MICA (P) 068/04/2013 and MICA (P) 110/01/2013

[386783]



Kevin Logan
Chief Economist, US
HSBC Securities (USA) Inc
+1 212 525 3195
kevin.r.logan@us.hsbc.com



David Phillips*
Global Co-head of Oil, Gas & Petrochemicals Research
HSBC Bank plc
+44 20 7991 2344
david1.phillips@hsbcib.com



Thomas Hilboldt*
Head of Oil, Gas & Petrochemicals Research, Asia Pacific
The Hongkong and Shanghai Banking Corporation Limited
+852 2822 2922
thomaschiboldt@hsbc.com.hk



Nick Robins
Head of HSBC Climate Change Centre
HSBC Bank plc
+44 20 7991 6778
nick.robins@hsbc.com



Jorge Morgenstern
Economist, Argentina, Chile, Uruguay
HSBC Bank Argentina SA
+54 11 4130 9229
jorge.morgenstern@hsbc.com.ar



Paul Bloxham
Chief Economist, Australia & New Zealand
HSBC Bank Australia Limited
+612 9255 2635
paulbloxham@hsbc.com.au



Andre Loes
Chief Economist, Latin America
HSBC Bank Brasil SA – Banco Múltiplo
+55 11 3371 8184
andre.a.loes@hsbc.com.br



David Watt
Economist, Canada
HSBC Bank Canada
+1 416 868 8130
david.g.watt@hsbc.ca



Sergio Martin
Chief Economist, Mexico
HSBC México, SA, Institución de Banca Múltiple
+52 55 5721 2164
sergio.martinm@hsbc.com.mx



Simon Williams
Chief Economist, Gulf
HSBC Bank Middle East Ltd
+971 4 423 6925
simon.williams@hsbc.com



Agata Urbanska
Economist, Central and Eastern
Europe
HSBC Bank plc
+44 20 7992 2774
agata.urbanska@hsbcib.com



Alexander Morozov
Economist, Russia
OOO HSBC Bank (RR) (Limited Liability Company)
+7 495 783 8855
alexander.morozov@hsbc.com



Simon Wells
Chief Economist, UK
HSBC Bank plc
+44 20 7991 6718
simon.wells@hsbcib.com



Ramiro Blazquez
Economist, Colombia, Peru, Venezuela
HSBC Bank Argentina SA
+54 11 4348 2616
ramiro.blazquez@hsbc.com.ar

*Employed by a non-US affiliate of HSBC Securities (USA) Inc, and is not registered/qualified pursuant to FINRA regulations.

Issuer of report: HSBC Securities (USA) Inc.