Deutsche Bank

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European Gas: A First Look At EU Shale-Gas Prospects

Commodities Special

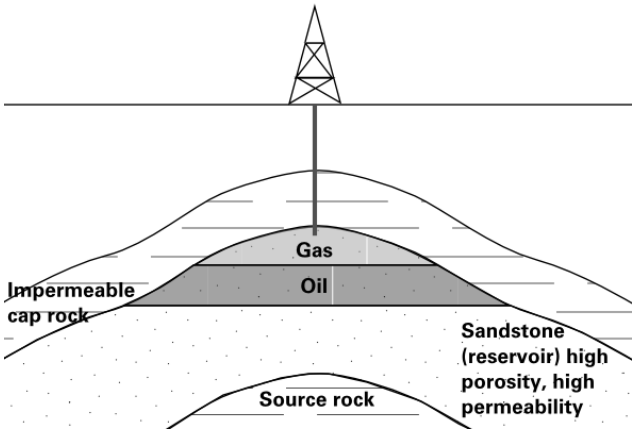
- **Recent estimates of UK shale-gas resources raise the possibility that declines in existing domestic production may in the future be offset to some extent by unconventional gas, although many uncertainties remain.**
- **Prime among these uncertainties are the size of the recoverable resource, the rate at which production can be achieved, and the extent to which the concerns of local residents and environmental groups can be accommodated.**
- **Owing to advantages in drilling-services infrastructure, mineral-rights law, and population density, the US is arguably better suited to the rapid development of shale-gas resources, implying that the rate at which shale-gas resources can be exploited elsewhere in the world will be more drawn out.**
- **Accordingly, while we expect the development of shale-gas resources to proceed in the EU, North Africa, and China, we also see limiting factors and higher costs than those in the US.**
- **As a result, whilst we think that EU shale-gas deposits certainly have the potential to contribute meaningfully to indigenous production over the next 10-20 years, we do not expect the impact of shale-gas production on EU gas prices to be anywhere near as great as has been the case with US shale-gas production on Henry Hub prices.**

Shale-gas basics

Shale-gas deposits hold a combination of free gas (trapped in the pores and fractures of shale) and adsorbed gas (adhered to the surfaces within the shale), falling midway on a continuum of unconventional gas resources between tight-gas deposits (only free gas) and coal-bed methane (only adsorbed gas).

Conventional gas deposits differ from unconventional deposits in that they are reservoirs of gas that have migrated from the original source rock. These reservoirs, typically composed of sandstone or carbonate, hold oil and gas which has migrated from the source rock, under pressure beneath an impermeable rock layer. The gas can be recovered through a vertical well since the combination of natural reservoir pressure and high porosity allows gas from a relatively large area to travel up the well bore (Figure 1).

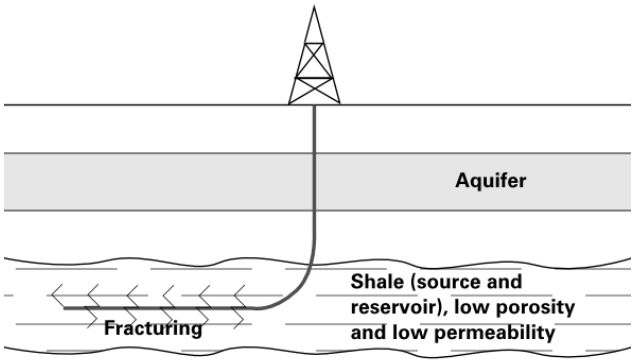
Figure 1: Conventional gas deposit and recovery



Source: Deutsche Bank

In contrast, shale gas is held in rock which has retained the bulk of its hydrocarbon content and which acts as both source and reservoir. This rock typically has smaller, less well-connected pores and requires horizontal drilling to expose the wellbore directly to a greater volume of the source rock. Shale-gas wells also require multi-stage hydraulic fracturing to create a network of connected faults in the source rock which allow commercial amounts of gas to travel to the wellbore (Figure 2).

Figure 2: Shale-gas deposit and recovery



Source: Deutsche Bank

High initial flow rates result from the release of free gas which declines relatively quickly over the first several years, after which productivity levels out at a lower, steady rate during which adsorbed gas is released from the rock formation. High production rates can be enhanced and prolonged by drilling across naturally existing fractures and repeatedly stimulating a well by additional fracturing. Nevertheless, decline rates tend to be higher than for conventional wells.

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Shale-gas exploration outside the US in early stages

In assessing the productive potential of gas shales outside the US, we should remember that exploration of US shale began in 1977 with the Eastern Gas Shales Project (EGSP). Under this programme, geologists mapped Devonian shale formations in the Appalachian, Illinois and Michigan basins, while engineers investigated fracturing and directional drilling methods.

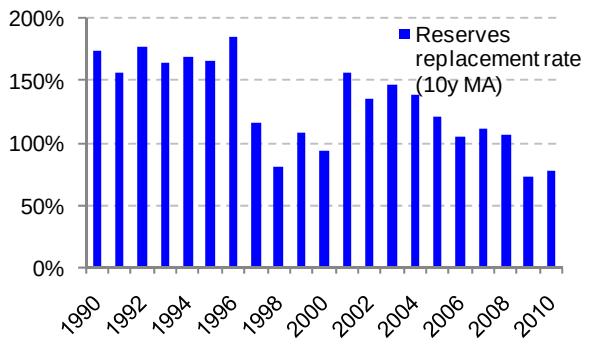
In the late 1990s, Mitchell Energy was the first to develop a light-sand fracturing technique which uses less water and is more economical. Subsequently, production from the Barnett Shale rose from very low levels to 10bcm in 2004 and 45bcm in 2008, according to the Centre for Global Energy Studies. Today, the fracturing of a shale-gas well requires between 1 and 5 million gallons of water, according to the US Shale Gas Subcommittee.

While US exploration efforts have not been uninterrupted since the EGSP, and development efforts outside the US will certainly benefit from technology transfer, this nonetheless points to a significant headstart. As such, resource potential outside the US has been judged primarily on the basis of geological similarity to various US shale basins. Such estimates are fairly speculative as a result, and confidence in these estimates would only be strengthened as and when exploratory wells are drilled.

Expected declines in EU conventional production

Across Europe, conventional gas resources are well understood, while recent discoveries have been trending smaller in size, resulting in a reserves replacement rate of only 78% in the ten years ending in 2010, according to the BP Statistical Review of World Energy (Figure 3). A reserves replacement rate of 100%, over the long term, is necessary to maintain production at the current level.

Figure 3: Reserves replacement rate (10y average) in Netherlands, Denmark, UK and Norway combined

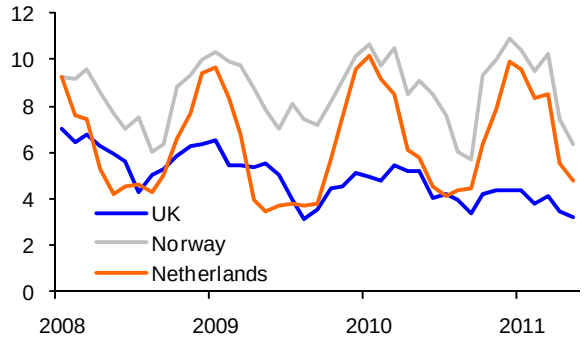


Source: BP Statistical Review of World Energy 2011

A decline in domestic production is already well underway in the UK, with volume dropping by 9% annually on average since 2004. Even in the Netherlands, one of Europe's largest exporters, gas production will likely begin to fall towards the end of the decade.

In Norway, recent downgrades of recoverable reserves are a source of worry, although recent exploration in the Barents Sea is promising. Wood Mackenzie expects Norwegian production to maintain the current level through 2017, but for Dutch production to fall by 11% in 2017 in total from this year's level, and UK production by a further 19% in total from this year's level.

Figure 4: Gas production in Europe and Norway (bcm/month)



Source: DECC, NPD, NLOG, Deutsche Bank

UK shale gas holds out hope

Recent estimates of the total reserves contained in UK shale-gas deposits hold out the hope that the decline in UK production could be slowed in coming years.

On 21 September, Cuadrilla Resources estimated the total gas-in-place in the Upper Bowland Shale of the Pennine Basin near Blackpool at 5.7tcm. We should be careful to distinguish the size of the total resource from the recoverable resource, which may be significantly less than the total gas-in-place, although higher recoverabilities can be achieved when either natural fractures are present or refracturing is performed. By way of reference, the UK consumed 0.09tcm of natural gas in 2010, excluding exports to Belgium.

Too early to estimate impact of UK shale-gas resource

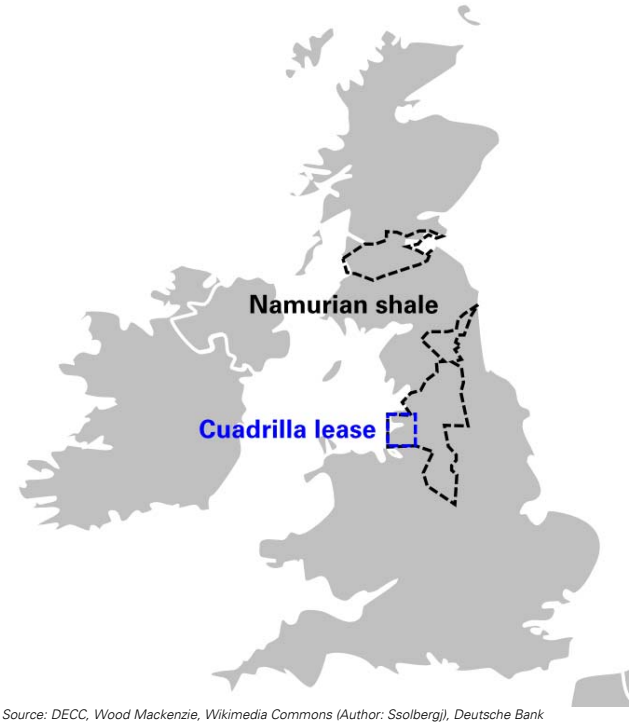
However, there remains considerable uncertainty regarding the size of the recoverable resource and the production rates that could be sustained. The stated resource estimate is based on only two wells having been drilled, whereas seven wells may be required before recoverable reserve estimates can be made.

Therefore, we believe it is too early to judge the recoverable resource size, let alone what commercial production rates may be possible. According to the British

Geological Survey (BGS) in December 2010, "there are no reliable indicators of potential productivity" of shale gas in the UK in advance of drilling and testing.

Previous estimates on the size of the UK shale-gas resource have varied widely, and have generally been based on analogy with similar known shale gas plays in the US. The BGS estimated the UK shale-gas reserve potential at 150bcm, while the US EIA estimated technically recoverable reserves at 560bcm in April 2011.

Figure 5: Namurian shale (incl. Upper Bowland Shale)



Source: DECC, Wood Mackenzie, Wikimedia Commons (Author: Ssolbergj), Deutsche Bank

Environmental concerns are paramount

Aside from the technical challenges, environmental risks are a key concern which will need to be addressed.

On 11 August 2011, the Shale Gas Subcommittee of the U.S. Secretary of Energy Advisory Board released a 90-day interim report concerning the environmental impacts from shale gas production (a 180-day final report is expected on 18 November 2011). It identified four major areas of concern: (i) possible pollution of drinking water, (ii) air pollution, (iii) community disruption, and (iv) cumulative adverse impacts on communities and eco-systems.

The subcommittee recognised that although a single best engineering practice cannot be applied universally, identification and employment of best practices can reduce environmental impacts. The recommendations of the sub-committee are wide-ranging and indicate that many existing technologies can be deployed to effectively reduce many of the adverse impacts listed above.

These recommendations are to (i) improve availability of information to the public through the creation of a national database on shale-gas development and production, (ii) improve air quality through (a) capture or flaring of methane emissions and (b) conversion from diesel to natural gas or electric power for oil-field equipment, (iii) protect water quality by (a) adopting a life-cycle approach to water management and (b) through proper disposal of flow-back and produced water, (iv) background water-quality measurements and (v) disclosure of all chemicals used in fracturing fluids, not just those appearing on Material Safety Data Sheets (MSDS).

Specifically on the issue of methane migration into drinking water, the sub-committee identified two primary modes by which this can occur as (i) the loss of well integrity owing to poor well completion and (ii) the uncontrolled vertical growth of hydraulic fractures. The sub-committee indicated that best practices such as pressure testing of well casings and frequent micro-seismic surveys can effectively curtail the occurrence of methane migration in these modes. Limiting vertical fracture growth also has the positive side benefit of reducing the volume of water required.

If these findings are true, then it means that environmentally safer development practices, although likely to be more costly and time-consuming, will meaningfully mitigate the most troublesome adverse impacts attributed to shale-gas development and production.

Cumulative impact may still be high

However, the sub-committee also recognised that the intensive development can have serious impacts on the local community and ecology even when operators abide by all applicable regulations, especially in regards to transport traffic, water use, noise, air and visual pollution. Therefore, local officials should adopt a holistic view when evaluating cumulative impacts.

In addition, we would agree with the subcommittee that a credible assessment of the end-to-end emissions profile of natural gas through the life-cycle of development, production, delivery and consumption is long overdue given the emphasis which has been placed on natural gas as an environmentally desirable replacement fuel for coal and crude oil.

UK government supports exploration

The UK government's position on unconventional gas is positive for shale-gas prospects in the UK. The

Environment Agency has previously reviewed and approved drilling plans in the Bowland Basin, based on an assessment of the risks to the environment and water resources. Charles Hendry, the Minister of State for the Department of Energy and Climate Change (DECC), supports unconventional gas exploration for its potential in improving security of supply.

In addition, the environmental furor over hydraulic fracturing could arguably be a positive for UK unconventional production. The absence of serious adverse events thus far in the UK means that UK producers have the benefit of a "clean slate," at least locally. However, we would emphasize that no production has yet taken place, and drilling on a commercial scale will carry greater risks than exploratory work.

In light of the fact that highly publicised environmental concerns in the US have halted exploration in France and slowed development in Germany, we believe that UK exploration companies will take extra care to ensure the safety of drilling operations. This would safeguard what is so far a clean record, a crucial advantage in the current climate.

However, there are at least four factors which we think could work against the large-scale production of shale gas outside the US: (i) population density, (ii) mineral-rights law, (iii) well costs, and (iv) the structuring of oil-and-gas leases.

Factor 1: Population density

The first factor applies in any country which is relatively densely populated. The wider distribution of shale-gas resources, relative to conventional deposits, requires a larger number of wells for a given volume of production. Shale-gas production also requires large volumes of water, which must be transported by many truckloads, creating traffic and noise on local roads. Produced water must also be held in reservoirs on-site.

In the UK, with a population density of 259 people/km² (compared with the US, 34 people/km² and China, 139 people/km² according to July 2011 estimates from the CIA World Factbook), the impact to the landscape and quality of life of drilling operations will likely be felt more acutely. A point of caution is in order, however, as regional population density in shale-gas regions may differ materially from the national average.

In Cuadrilla's mid-case scenario for its UK lease, 400 production wells could be drilled at 40 well pads, or sites, which cumulatively would have an impact on local populations. While a completed gas well head is unobtrusive compared to a drilling rig, each site would likely cover several acres and include a containment pond, condensate storage tanks and compressor station, all of which disrupt the landscape and create noise.

This may make it difficult and time-consuming to acquire local planning permission. We believe this is a real issue, as in the case of the proposed construction of a natural gas pressure-reduction installation at Corse in Gloucestershire, UK, the Forest of Dean District Council refused planning permission in October 2007 owing to the adverse impact of industrial installations on the appearance of the countryside. Permission was eventually granted in December 2010 at a nearby site, although community opposition continues to this day.

In the worst case, similar objections could prevent producers from obtaining planning permission for gas drilling pads, and require a greater spacing between the pads that can be permitted, leading to a lower recovery rate of gas-in-place and lower productivity rates. At the very least, it may be more costly to produce gas if additional measures are required to minimise the visual and auditory impact to local communities.

Factor 2: Mineral-rights law

The rights to all oil and gas in the UK have belonged to the government since the Petroleum Production Act 1934. We note that this is the case in most countries around the world, to which the US is an exception. In the US, both surface rights and mineral rights belong to the landowner.

This fact results in two important differences with regard to the development of shale gas. In the US, up-front bonus payments and production royalties accrue directly to the landowner. This income is substantial enough that it can offset the potentially negative impacts to the local resident. In addition, since the landowner stands to benefit directly, the licensing process can proceed more quickly. In other countries including the UK, licensing rounds for exploration and production involve central government approval and can be a more protracted affair, lengthening development times and adding to costs.

This point has not been lost on producers, including Cuadrilla which stressed the possible tax revenues of £120m to local councils and £5-6bn to the government, according to Reuters.

In the short term, we note that hydraulic fracturing is currently suspended in the UK pending an investigation into seismic activity nearby. Cuadrilla has stated that commercial production could start in mid-2013.

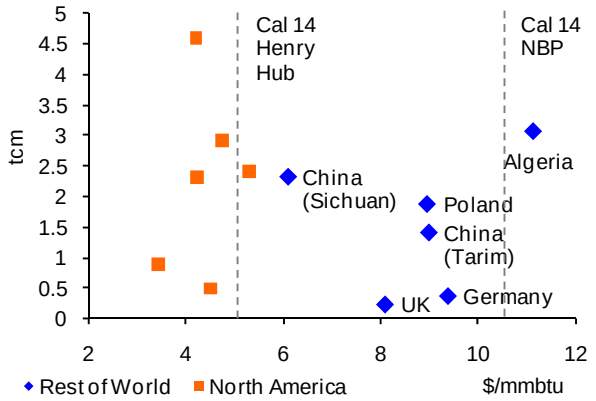
Factor 3: US well costs significantly lower

A third obstacle currently faced by European and North African shale-gas ventures is relatively high well costs, ranging from $6.5 million (m) to $14m, in comparison to $4m at the Marcellus Shale in Pennsylvania. This gives higher post-tax gas breakeven costs (Figure 6) versus the US.

The US shale-gas industry derives this pricing advantage from the presence of a well-developed drilling-services sector. At the peak in 2008, roughly 1,600 gas drilling rigs were in operation in the US, while fewer than 100 such rigs are in operation in Europe. According to Wood Mackenzie, only 100,000 horsepower (hp) of hydraulic-fracturing equipment is available in Europe, compared with 8.0 million hp in the US.

As exploration investment rises, new drilling companies enter the market, and competition increases, costs are likely to fall. However, we would be hesitant to claim that this would necessarily reduce costs to the level of current US projects since labour costs, health-and-safety regulations, and more stringent environmental requirements may result in a persistently higher cost base.

Figure 6: Shale-gas post-tax full-cycle breakeven costs ($/mmbtu) and resource potential (tcm)



Source: Wood Mackenzie, Deutsche Bank

As a result, unless full-cycle production costs can be significantly reduced, the widespread development of shale-gas reserves around the world may contribute to reserves and production, but is unlikely to lead to a pricing revolution at the current Henry Hub level. At the same time, higher forward prices in Northwest Europe mean that some European shale plays can nevertheless be economical (Figure 6).

Factor 4: US oil-and-gas leases are uniquely structured

A fourth and final factor which serves to differentiate the US operating environment from other jurisdictions is the existence of continuous drilling obligations. US oil-and-gas leases commonly contain a provision which requires that producers maintain ongoing drilling and developmental activities, with no cessation of longer than 90 days.

In truth, this is an indirect effect of US common law which places mineral rights in the hands of landowners. Lessors benefit from a royalty share of production revenue before costs, and so have an interest in sustained production rates regardless of profit margin. This factor has often been cited to explain why production from US gas acreage continues at high rates despite prices being near breakeven costs. To our knowledge, such provisions do not typically exist in oil-and-gas leases outside the US.

Shale-gas initiatives in or affecting the EU market

Globally, shale-gas initiatives are underway in a number of regions, having taken inspiration from the US example. Of the countries with shale-gas projects in progress, those with a direct influence on European gas balances are Algeria, Libya, France, Germany, Poland and Ukraine.

However, the resource in China also bears mention, both because of its sheer size and because its development could well influence China's demand for Central Asian gas resources, which are also sought after by European countries for a new generation of Southern Corridor gas pipeline projects.

Algeria

In Algeria, ENI signed a cooperation agreement with Sonatrach, the Algerian state utility, in May 2011 to assess technical and commercial feasibility of shale-gas exploration. By law, Sonatrach is accorded 51% ownership of any exploration project. The motivation for developing shale resources will likely be tied to the decline of the giant Hassi R'Mel gas field. To the extent that this decline rate is gradual, Algerian interest in developing shale gas may be somewhat muted.

Figure 7: EIA estimates of technically recoverable shale-gas resources (tcm)

Country	Technically Recoverable Shale Gas Resources (tcm)
China	36.1
United States	24.4
Argentina	21.9
Mexico	19.3
South Africa	13.7
Australia	11.2
Canada	11.0
Libya	8.2
Algeria	6.5
Brazil	6.4
Poland	5.3
France	5.1

Source: U.S. EIA

Libya
In Libya, the EIA estimate of technically recoverable shale-gas reserves is 8.2tcm based largely on an assessment of the Sirt and Etel Shales in the Sirt Basin of eastern Libya. However, no exploratory projects have yet been announced.

France
In France, the government issued two exploration licenses to Schuepbach Energy and one exploration license to Total last year, valid for a period of five years. In May 2011, the government banned hydraulic fracturing on the basis of environmental concerns.

For a while, it appeared that shale exploration could proceed using conventional techniques, and Total stated in September 2011 that it would explore without the use of hydraulic fracturing, according to Reuters.

Those hopes were dashed on 4 October 2011 when the government cancelled the three exploration permits issued in 2010, citing drilling plans recently submitted by Shuepbach and Total which still included hydraulic fracturing. No exploratory drilling had been accomplished on the permits.

On the same day, President Sarkozy has stated that France would not permit hydraulic fracturing until it is proven to be "environmentally clean."

Germany
In Germany, ExxonMobil has been drilling vertical study wells since 2008, completed four exploratory shale wells by January 2011, and previously had planned for investment of $1bn over the five years to 2015. However, the state of North-Rhine Westphalia instituted a moratorium on further shale-gas drilling in March 2011. A history of politically active environmental groups in Germany may continue to hamper exploration progress.

Poland
Poland perhaps represents the most aggressive environment for shale-gas development as the government aims to reduce its reliance on Russian gas exports. Prime Minister Donald Tusk has indicated that commercial production could begin as early as 2014, and expects that Poland may be self-sufficient in natural gas by 2035. According to Reuters, ExxonMobil has six licenses and is now planning a second test well near Siennica, while state-owned PGNiG holds 15 shale concessions and is planning to drill six test wells in 2012.

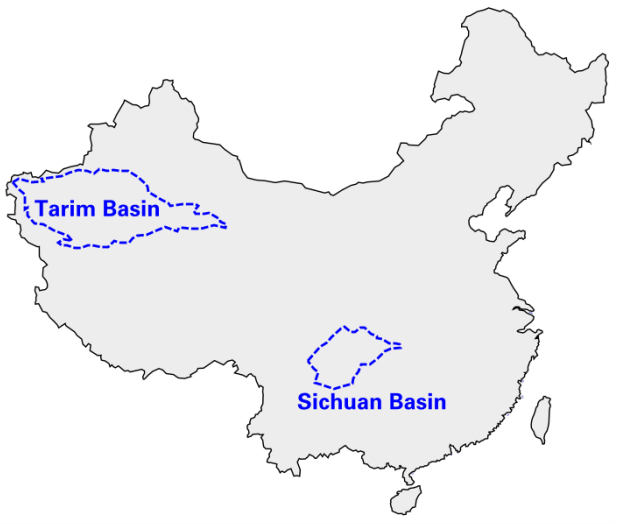
Ukraine
In Ukraine, similar motivations are likely behind the first shale-gas exploration contract, awarded to Royal Dutch Shell in September 2011. On 30 September, the state energy company, Naftogaz, signed a preliminary agreement with ExxonMobil on shale-gas exploration and development. Energy and Coal Minister Yuriy Boyko believes that exports of shale gas could be possible in the next seven to 10 years.

China
In China, the government campaign to develop shale gas is in an early stage, having begun in late 2009. The US-China Shale Gas Initiative of November 2009 was signed to promote technology-sharing, joint technical studies and investment to accelerate shale-gas development. According to an official at China's Ministry of Land and Resources (MLR), the government will encourage investment into exploration and development of shale gas, while seeking to introduce competition and pass laws on resource management, according to Xinhua News.

China's interest in developing shale gas is an extension of its overall energy plan, which aims at an 8.3% share of natural gas in primary-energy consumption by 2015, up from 3.8% in 2008. In 2010, the Strategic Research Centre for Oil and Gas set goals to locate 1tcm of recoverable shale gas, and build 15-30bcm of production capacity by 2020. In June 2011, the MLR awarded two shale-gas blocks to CNOOC and Chesapeake Energy.

Given the very early stage of many exploration programs, we note that estimates of the volume of technically recoverable gas reserves vary significantly depending on the source of the information, and are subject to change.

Figure 8: China's major shale-gas basins



Source: EIA, Wikimedia Commons (Author: Joowwww), Deutsche Bank

There is particularly large variability in estimates relating to China shale-gas reserves in the Sichuan and Tarim basins. While in Figure 6, Wood Mackenzie indicates resource

potentials of only 2.3 and 1.4tcm, respectively, the April 2011 EIA report estimates technically recoverable shale gas from the Sichuan Basin at 19.6tcm and from the Tarim Basin at 16.5tcm for a total of 36.1tcm.

Both of these measures are "risked" gas-in-place figures, meaning that they represent only the portion of total gas-in-place which can likely be recovered through currently available technology, but without regard to profitability.

Although the EIA states that reservoir quality remains uncertain, the Central Uplift of the Sichuan Basin is promising owing to its simple structure and relatively few faults. Notably, PetroChina reportedly experienced gas kicks while drilling in the Sichuan Basin, indicating overpressure, which is a necessary condition for high production rates. The Sichuan Basin also benefits from an existing infrastructure for bringing gas to market.

On the negative side, relatively high clay content in some areas of the Sichuan Basin may be problematic as it causes swelling during the process of hydraulic fracturing. Also, the population density in the Sichuan Basin in southeast China is much greater than that in the Tarim Basin in northwest China, which would likely necessitate a greater spacing between wells and therefore lower productivity.

Global shale-gas development is promising

Overall we believe that shale-gas developments worldwide have the potential to add meaningfully to gas production in the long term, provided that the industry can allay environmental fears and cost-effectively minimise the impact felt by local populations.

However, there are four factors which differentiate the US operating environment from other countries and lead us to believe that those waiting for a shale-gas "revolution" outside the US will likely be disappointed, in terms of both price and the speed at which high-volume production can be achieved.

Furthermore, timeframes, economics, resource sizes and productivity rates are subject to large uncertainties which will only be resolved over time, through the exploration process.

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Appendix 1

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