crédito y caución
Atradius Group

Gas Market Outlook
July 2014

Editorial

The price of commodities affects a wide variety of industries, from manufacturing to retailing, and can have a huge impact on company earnings, margins and thus profit. It is with this in mind that in late 2012 Atradius Economic Research began a project designed to explain to those many businesses for which this is a critical issue how commodity prices are established and what factors affect them. Our endeavours resulted in the first publication, the Oil Market Outlook of April 2013. Now we have produced the second one in the series, on gas.

Atradius' knowledge of the gas industry is extensive: our analysis and risk assessment of gas producing countries and of the gas market in general is crucial to our broader task of risk management and support for our customers in their credit management. We aim, through our series on commodities - in this case gas - to share our knowledge and, in doing so, provide the reader with a guide to that market and the direction in which it is heading.

Compiling this report required a huge amount of research. As well as drawing on our own resources, we have been assisted in our venture of capturing the essentials of the gas market by the Clingendael International Energy Programme, which designed a day's programme to grasp the essentials of the gas market. Additionally, we were helped by discussions with colleagues from the International Energy Agency (IEA), to whom we are most grateful.

I would like to thank my colleagues Marijn Kastelein and Afke Zeilstra who conducted the research on Asia and Europe, and drafted the text on those parts. Daan Willebrands carried out the indispensable task of pre-reading the manuscript, provided suggestions to to upgrade the text and was also instrumental in the final layout of the report. Simon Groves, last but not least, read the text with his usual scrutiny and improved it where he saw fit.

John Lorié, Chief Economist Atradius

Table of contents

Executive summary

This Gas Market Outlook complements the Oil Market Outlook that we published in April 2013. As in that report, here we want to guide our readers through the market so that they get a clear picture of the outlook for this industry.

With this in mind, our first task is to provide overall guidance to our readers by summing up the six major takeaways from this report:

1. Regional markets connected by trade
Unlike oil, there is no such thing as a global gas market. There are only regional markets, connected by trade: with the United States, Asia and Europe the essential regions. Trade and transport of gas is by pipelines and the more expensive Liquefied Natural Gas (LNG) vessel transport.

2. Price divergence between regions
Prices in the various regions have diverged since the early days of the millennium, highlighting underlying differences in market characteristics. US gas prices are market based and have been under pressure, reflecting the rapidly growing availability that comes with the shale gas revolution. Gas prices in Asia are linked to the price of oil and, with the surge of the latter and the growth in gas consumption resulting from economic development, Asian gas prices have tripled and are now by far the highest in the world. Europe's gas prices are partially linked to the price of oil, which explains why they have roughly doubled.

3. US shale gas revolution
This very recent phenomenon is the product of a combination of favourable technical, financial, environmental and entrepreneurial circumstances in the US. The resulting production surge depressed prices and led to the substitution of coal for gas in the power sector ('The Switch'). Imports of natural gas have halved over the past decade. The developments are likely to last into the medium-term future as the US becomes self-sufficient in gas. Over time, US exports of gas via LNG will also start to play a role in supporting further production growth, given the price difference between the US and Asia. US prices will climb gradually as a result.

4. Asian demand triggering LNG boom
Asian gas supply has been unable to keep up with the fast rise in demand. The resulting supply deficit is covered mainly by LNG imports. The surge in gas prices has triggered a flurry of investments in LNG facilities, particularly in Australia, and LNG is expected to grow further. Chinese non-conventional gas production should also take off and relieve upward pressure on prices. If Chinese production rises, US exports develop and the LNG cost can be contained, future prices can be expected to remain around the current levels.

5. European energy policy with perverse outcomes
Focus on environmental issues has led to a EU-wide trading system of carbon emission and a renewable energy policy in Germany. But, perversely, the measures have reduced gas consumption in the power sector and encouraged the use of coal: a much more polluting energy source. Gas production is gradually declining, while demand may pick up on the back of improving economic conditions. This will eventually put upward pressure on gas prices. More market based pricing (rather than oil price linked) is also expected to take place. Russia, Europe's main supplier, is expected to benefit, although commercial and political reasons will push European countries to diversify suppliers. LNG imports, even from the US, might play a role over time.

6. Price convergence between regions ahead
As US prices gradually climb, the Asian prices will remain at current levels. With European prices witnessing some upward pressure, we see price convergence between regions, reversing the trend of the past decade. Greater than envisaged US exports, like the acceleration of the erosion of oil based pricing, could reinforce this process: Asian and European prices will consequently be lower.

Return to contents page

Part 1 - Introduction

After decades with little interest happening, the global gas market has shown unprecedented dynamism in the past ten years. The application of innovative drilling technology in the US has created a new paradigm, with US gas production accelerating to levels previously unimaginable. Global reserves have risen spectacularly as unconventional drilling methods give access to previously unexplored gas wells. Meanwhile, Asian gas demand has accelerated with economic growth and growing environmental awareness. The demand spur coming from that region and the continuing high gas price have triggered a wave of investments in Liquefied Natural Gas (LNG) facilities, particularly in East Africa and West Australia. Pipeline supply simply cannot meet expected demand. Although Asia offers opportunities for US exports, because of the surplus volume accruing and the relatively low price in the US, these exports are still restrained by US law for strategic reasons. The law will inevitably be softened, further pushing up interregional trade in gas, which is now already 80% higher than in the early nineties. With this sudden market dynamism, contracting terms and pricing mechanisms are under pressure as consumers will have many more choices of suppliers. The gas market is rapidly changing.

1.1 Motivation and objective

In April 2013 we published our Oil Market Outlook: a guide and an outlook for that market. Now we are essentially doing the same for the gas market and, as with the oil market outlook, it is both a guide and an outlook. We will explore developments in the gas market in some detail and provide the reader with an overview of the key mechanisms that are at work. That will hopefully allow the reader to better assess future developments in this dynamic market. We'll sketch out those future developments too: for the period up to 2018 and, further ahead, to 2035.

1.2 Approach

Given the structure of the gas market, our approach is slightly different from the one taken in the oil market – because, unlike the oil market, there is no global gas market as such. Discussion of global demand, supply and prices would therefore not make for an easy read. Instead, we should distinguish three different regional markets, with different supply, demand, price and contract characteristics: the US, Asia and Europe. Treatment of these regional markets, including the outlook, is at the heart of this report. But, at the same time, these regional markets cannot be viewed completely in isolation, as they are increasingly connected through trade. That warrants the first and the final part of our report, in which we take a global perspective and discuss, respectively, current gas prices and their underlying characteristics, and the outlook of prices for 2018 and 2035.

1.3 Reading guide

We start, in Part 2, by sketching out the essentials of the gas market: a picture of, and developments in, global gas reserves, production, consumption and trade. We observe that global reserves have proliferated on the back of the US shale gas revolution and that US production has risen spectacularly. Asian demand is developing rapidly too, triggering the LNG investment boom. This background helps us to better understand current prices in the various regions, which have diverged markedly.

Then, in Parts 3, 4 and 5, we focus on regional market developments and characteristics in the US, Asia and Europe. We take a simple approach: first establishing the importance of gas in comparison to other energy sources - notably oil and coal - and then discussing demand, supply and price mechanism and developments. Inevitably, the US shale gas revolution is discussed in detail, as are the LNG investments generated by Asian demand developments. We also note the peculiarities of the European gas market, with its focus on environmental issues, which has led to a market outcome of increased pollution that is the precise opposite of the one intended. The analytical discussion in this section of the report is the basis for the subsequent outlooks for the three regions: the medium and longer-term perspectives of 2018 and 2035.

In Part 6 we return to the global perspective as we summarise and interpret the regional price developments for the two outlook periods, as well as identify the underlying risks to this outlook. Unless these materialise, however, we see price divergence among the regions ending by 2018, and even reversing. Notably, the US shale gas revolution and LNG expansion are driving forces behind this. There is a limit to price convergence, as the baseline outlook for 2035 underlines. Price levels will go up in that outlook period, however, as Asian demand, primarily, is expected to continue to grow.

1.4 Must reads

A comprehensive discussion of, the essentials of the gas markets requires and deserves a substantial report. However, because some readers may have limited time, we feel that we should point to sections in our report that we believe to be indispensable. In our opinion, these are:

- The sections on current prices (2.3) and the price outlooks for 2018 and 2035 (6.1 and 6.2).
- The sections discussing the major developments in the regions that have a global impact: 3.1 for the US shale gas revolution, 4.2 for LNG and 5.2 and 5.3 for the European policy intricacies.

These are the ‘must reads' of this report. Of course, we hope that reading these parts will encourage readers to turn to the other parts of the report as well.

Return to contents page

Part 2 – The Global Gas Market

To act as a guide, this part first takes stock of the basic characteristics of the gas market. We sketch the picture of, and some developments in, global gas reserves, production, consumption and trade. This will allow us to better understand current gas prices. We stress the plural -'prices' - because, unlike oil, there is no one world price for gas. More specifically, each gas region that we have identified – the US, Europe and Asia - has its own price and these prices have diverged since the early years of this millennium.

2.1 Global gas reserves and production

Gas resources can be divided, on the basis of drilling method, into conventional and unconventional resources. For unconventional gas, more complicated techniques like hydraulic fracturing and horizontal drilling are necessary to obtain gas from shale formations, limestone or even coal beds (coal bed methane). Gas drilled in this way is therefore described, respectively, as shale gas, tight gas and coal bed methane.

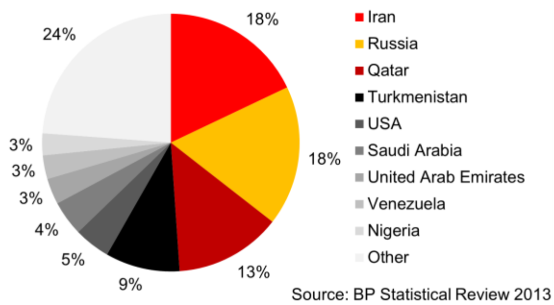
It is precisely in this area - obtaining, unconventional gas - where major changes have taken place, and are still taking place, triggered by developments in the US. These developments have been labelled 'the shale gas revolution', marking the rapid acceleration of, particularly, shale gas drilling in the US. This shale gas revolution really has had an impact.

Firstly, it has led to a considerable upward revision of global gas reserves. Following a report of the US International Energy Agency (IEA, 2013) about global shale formations, the reserves for several countries have been revised upwards. With the unconventional reserves included, the world gas reserve was 810 trillion cubic metres (tcm) by the end of 2012, an upward revision of 47%. The largest technically recoverable reserves are not in the US, but rather in China, Argentina and Algeria. However, these countries, unlike the US (and Canada), do not yet exploit shale gas in commercially viable quantities.

It is not just unconventional reserves that have increased. Conventional gas discoveries are also still being made and recently the largest of these discoveries has been made in Mozambique.

The reserves referred to are technically recoverable and should be distinguished from the more conservatively defined proved reserves. These proved reserves can be profitably extracted with available technology and under existing market conditions, and stood at 187 (trillion cibic meters (tcm) at the end of 2012 (BP Statistics, 2012). That figure has also increased: 20% higher compared to 2002 (155 tcm). The largest gas reserves in the world are in Iran and Russia (Chart 2.1).[1]

Chart 2.1 Total gas reserves
(Share in total reserves, 2012)

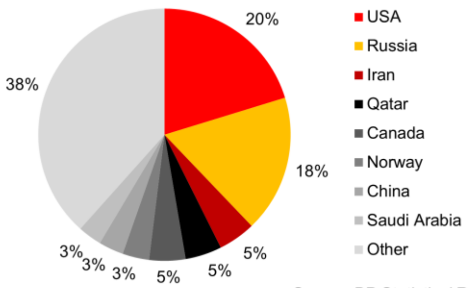


Source: BP Statistical Review 2013

Secondly, and perhaps unsurprisingly, US production has increased spectacularly over the past couple of years: 6.3% per annum growth in 2010-2012 against 0.1% in 2000-2010. This compares to global production growth of 2.4% in 2010-2012 against 1.1% per annum for the period 2000-2010. The shale gas revolution has had a major impact on production in the US and globally. In 2012 the largest global gas producers were the US, with a 20% share of total global production, and Russia, with an 18% share. The third largest producers are Iran, Qatar and Canada, each with 5%.

[1] Proven reserves are therefore a very conservative estimate of technologically recoverable reserves for which drilling success contains more uncertainty. See e.g. http://oilindependents.org/oil-and-natural-gas-reserves-definitions-matter/

Chart 2.2 Total gas production
(Production in 2012)



Source: BP Statistical Review 2013

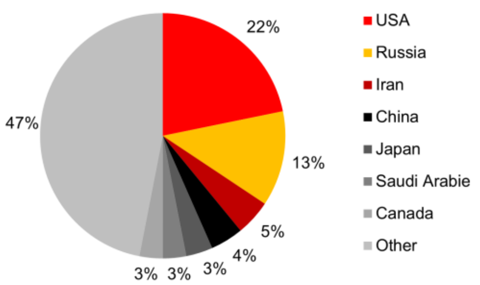
2.2 Global consumption and trade

Gas is one of the cleanest fossil fuels, but its share of the world energy mix is still behind the two main energy sources: oil and coal. Oil has a 31% share of total world energy demand, coal 29% and gas 21%. The energy mix can be different in various regions, depending primarily on the availability of fuels.

The largest gas consuming sector is the power sector, generating electricity. In the industry sector, gas is used as input for chemicals such as ammonia and plastics. In the real estate sector (residential and commercial) it is used for heating and cooking. Gas is also increasingly used in the transport sector, but usage is still quite small.

As Asian economies developed rapidly in the past decade, so did their gas consumption. Since 2002, Asian consumption as a share of global consumption has grown, to 19% in 2012, while the US and European shares have declined. However, the largest consuming countries are the US and Russia with a share of, respectively, 22% and 13%. (Chart 2.3).

Chart 2.3 Total gas consumption
(Sharing in consumption, 2012)



Source: BP Statistical Review 2013

Gas trade is effected through pipelines and Liquefied Natural Gas (LNG) distribution. In pipelines, gas is transmitted under high pressure through steel pipes. LNG trade is by way of liquefaction of gas (reducing the volume more than 600 times), transport by tankers and subsequently gasification for delivery to consumers. With costly liquefaction and gasification included in the process, LNG seems a poor competitor to pipelines. Even so, if long distances are involved, LNG is more economical: particularly if pipelines are technologically impossible or extremely costly, such as in the case of cross-ocean transport.

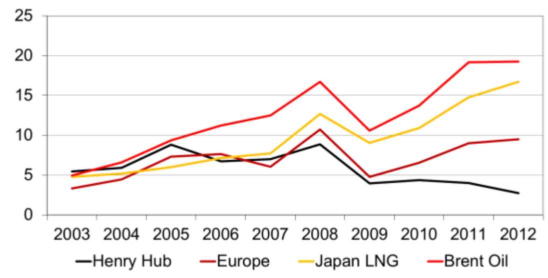
LNG trade is on the rise as a result of consumption growth in Asia, where production is limited (12.4% of global production and 22% of consumption). In 2012 Asia accounted for 30% of all natural gas trade, up from 22% in 2002. LNG accounts for more than three-quarters of natural gas trade between continents, particularly from the Middle East to Asia. Indeed, large LNG exporters include Qatar (32% of LNG trade in 2012), Indonesia (8%) and Algeria (5%). Japan is the largest importer (36%), followed by South Korea (15%). LNG is bought and sold on the basis of long-term contracts, broadly based on the oil price, but spot trades have more than doubled since 2000: to 27%.

In Europe and the US, most trade is by way of pipelines. Russia is a large exporter, with 26% of the world's pipeline trade, largely into Europe. Europe imports only 15% of its consumption by way of LNG. Pricing in Europe is still largely based on long-term contracts and oil prices, but market based spot pricing has made much more headway than in Asia. In the US, trade is by pipeline into and from Mexico and Canada, but the country is building LNG terminals to allow for exports, as we will discuss later in this Outlook. Pricing is market based, without any reference to oil prices.

2.3 Global prices

After a longer period of calm, prices started to move in the early years of the millennium. As we have already mentioned, the oil market is essentially global whereas for gas there are three, still largely segmented, markets: the US, Europe and Asia. Chart 2.4 shows the price development of oil and gas in the world. The reason that we have included oil prices is that gas prices are still largely oil price based in Europe and, particularly, Asia.[2] The graph below allows for broadly two observations. Firstly, before 2005 the oil price and gas prices in various markets showed a large co-movement. More recently, the oil price and gas prices have started to diverge. Secondly, the extent of divergence from the oil price after 2005 is different for the three markets, meaning that the gas prices for the different markets are also diverging. For Asia, and to a far lesser extent Europe, price co-movement largely still holds. However, the US price no longer shows any correlation with the oil price and diverges not just from the oil price but also the gas prices in the rest of the world.

Chart 2.4 Natural Gas and Oil Prices
(in USD/MBtu, 2003-2012)



Source: BP Statistics

The question is "What has caused these developments in the gas market?" To answer that question, we refer to the mechanisms used for contracting and pricing, which differ fundamentally between markets. We have seen in the previous section that, in Asia, long-term contracting and oil price indexation is dominant. This is the case in Europe as well, although to a far lesser extent: almost half of that market is supply and demand based (IEA, 2013). In the US the price is fully determined by supply and demand. These differences in contracting and pricing originate in a security of delivery issue: Asian and European countries are predominantly gas importers and cannot afford supply to be interrupted by e.g. political issues. In the US the security issue plays a far lesser -or perhaps no - role as gas is traded only with Canada and Mexico. This allows market forces to dominate pricing.

Until 2005 these differences in regional gas markets remained below the radar. But since then one factor rapidly started to manifest itself: the shale gas revolution in the US. With the application of technological innovation to drilling, gas became available in abundance in the US. This pushed the US price much lower as demand failed to keep pace with supply. Meanwhile the oil price continued to surge, pulling the Asian and, to a lesser extent, European gas price up: in the case of Asia, to an unprecedented level. By the end of 2012, the difference between the US gas price and the oil price had risen almost seven fold, and the difference between the US and Asian gas price more than six fold.

[2] The price of oil is adjusted to reflect energy content similar to the one of gas, which was also the rationale behind the initial linkage between gas and oil pricing (see Melling, 2010). In line with IEA (2013) we have used the factor 5.8 to adjust the oil price.

Return to contents page

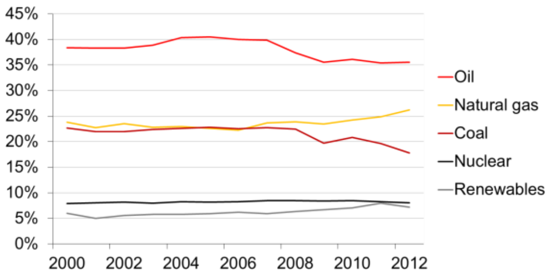
Part 3 – North America, United States

In this part we explore the developments in the region where the shale gas revolution has happened and provide the outlook until 2035. We will see that the share of gas in the US energy mix has risen significantly, at the expense of oil and coal. This highlights that the US gas market has fundamentally changed. The shale gas revolution rose due to favourable technical, financial, environmental and entrepreneurial circumstances. The resulting upsurge in shale gas production depressed prices and led to the substitution of gas for coal in the power sector ('The Switch'). Imports of natural gas have halved over the past decade. These developments are likely to last into 2018 as gas prices are expected to recover with the economic upswing, on-going consumption growth in the power sector and environmental requirements driving more gas fired power plants. The US will become gas self-sufficient. For the more distant future, until 2035, US exports of gas via LNG will also start to play a role in supporting further production growth, given the price difference between the US and Asia. For this positive outlook to materialise, the regulatory and environmental situation in the US will have to remain supportive.

3.1 The importance of gas in US energy consumption

Since 2000, US energy consumption has been at relatively stable levels. But this aggregate stability masks rapid underlying changes in its composition. At the expense of oil and coal, consumption of natural gas and, to a far lesser extent, renewables has gone up. More precisely, the share of oil and coal in total consumption declined by 6 percentage points between 2000 and 2012, with the share of natural gas and renewables benefiting from this. By 2012, 27% of total US energy consumption consisted of natural gas, making it the second most important energy source after oil.

Chart 3.1 US energy mix
(Shares in total consumption)

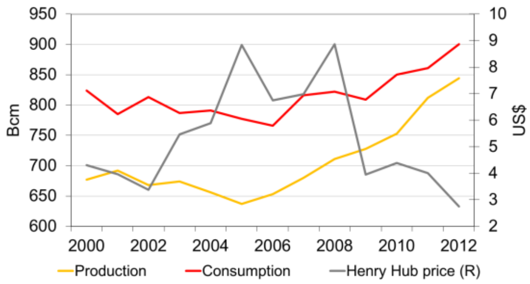


Source: IEA

3.2 The US natural gas market has fundamentally changed

Since 2005 US natural gas production has increased significantly, from 667 billion cubic metres (bcm) per annum in 2005 to 844 bcm in 2012: a 26% increase (see Chart 3.2). This has helped narrow the gap between production and consumption, and thus imports,[3] from 147 bcm in 2005 to 56 bcm in 2012. These developments are clearly reflected in the market price: Henry Hub prices were pushed down dramatically, from USD 9 per thousand British Thermal Units (MBtu) in 2005 to USD 2.8 in 2012.

Chart 3.2 US natural gas market
(Production and consumption 2000-2012)



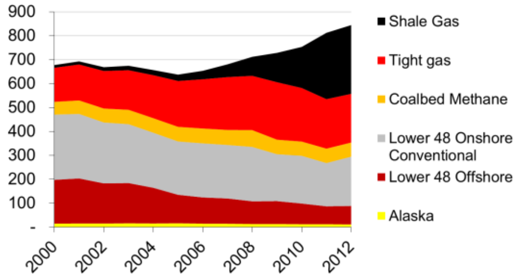
Source: BP Statistics

Underlying this state of affairs we can detect a number of developments. First and foremost, the

[3] US imports gas largely (95%) from Canada by pipeline, whereas the remainder is in the form of LNG primarily coming from Trinidad and Tobago (BP, 2013).

shale gas revolution. The production of shale gas has proliferated from 11 bcm in 2000 to 287 bcm in 2012, accounting for the lion's share of the 343 bcm increase in unconventional gas over the period.[4, 5] This unconventional gas production increase saved US gas production from significant shrinkage, as conventional gas production gradually declined due to depletion of existing wells.

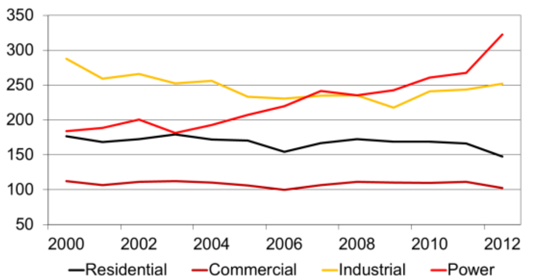
Chart 3.3 US gas production by method
(2000-2012 in bcm)



Source: BP Statistics

Secondly, this shale gas-led production boost and accompanying price decline has generated an increase in consumption of natural gas by 65 bcm over the period 2000-2012. But this was not a broad based increase. Rather, it was totally attributable to the increase in consumption in the power sector of 144 bcm. All other sectors showed a decline in consumption.

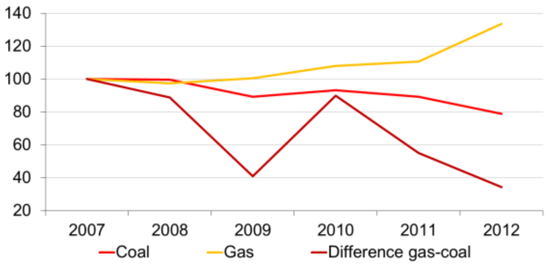
Chart 3.4 US gas consumption per sector
(In bcm)



Source: IEA (2013), Annual Energy Outlook

For the residential sector and commercial sector (encompassing all firms except industrial and agricultural) the decline was due largely to the unusually mild winter weather in 2012. This translates into a 10% drop in consumption, with residential demand alone losing 11% in 2012. The pattern of industrial sector gas consumption reflects the high gas prices in the early parts of the decade, the economic crisis of 2009 and subsequent muted economic recovery.[6] Not until 2012 did the US industrial sector return to its 2004 consumption level. Underlying the consumption increase in the power sector is a phenomenon called 'The Switch', representing the substitution of coal by gas in the power sector. While the gas price started to fall in the middle of the first decade of the millennium, due to the shale gas revolution, the coal price did not. The ever widening price difference between the gas and coal price drove the power sector to switching from coal-fired to gas-fired electricity production.[7]

Chart 3.5 The Switch: in US power sector
(Energy consumption, index 2007 = 100)



Source: IEA (2013), Annual Energy Outlook

Thirdly, the shale gas production boost has changed the trade flows of natural gas. US production rapidly expanded to unexpected levels, far exceeding the rise in consumption. This production increase was accommodated by a number of measures. Imports were nearly halved over the 2007-2012 period and storage was filled to capacity. But even that was not sufficient. Pipeline exports to Mexico and Canada began to accelerate, to 45 bcm in 2012 (5% of production), doubling over the last two years. And, conversely,

[4] Tight gas production increased by 60 bcm.

[5] 75% of the production of shale gas in the US takes place in the four major fields, Marcellus (Ohio, Pennsylvania), Barnett (Texas), Fayetteville (Arkansas) and Haynesville (Louisiana).

[6] Being a very small sector (0.1% of total demand), vehicle transport more than doubled its gas consumption, reflecting the significantly increased use of natural gas vehicles in the US.

[7] To put this in perspective, in 2012 coal-fired electricity generation fell by 216 Terra Watt hour (TWh) (13%) while gas-fired plants generated an additional 217 TWh (21%), an almost perfect substitution, as the gas prices fell 38% relative to the coal price.

Box 1 The US Shale Gas revolution explained

There are a number of factors that explain the US shale gas revolution. 150 years of drilling in the US have provided a wealth of geological experience of where to find new gas wells and where to drill. Incidentally, in many cases the unconventional wells overlie the conventional ones. By the 1980s a tax credit was designed to provide an incentive to switch from oil to gas drilling. This was further fine-tuned by way of a subsidy of 25% on the gas price. And, whereas the exploration of unconventional gas wells was initially inhibited by the lack of suitable technology, this changed in the early years of the millennium. Horizontal drilling and fracturing were increasingly applied: for example, for the Barnett Play in Mid Texas, 530 of the 920 wells were drilled horizontally in 2004, while this rose to 2,600 out of 2,710 in 2008. Moreover, regulation has been fairly free of environmental constraints, such as the potential contamination of ground water due to the use of chemicals in hydraulic fracturing.

This is largely because the unconventional technology is simply so different that it takes time to incorporate it into the existing regulatory framework. The nature of subsoil property rights assisted the development as well. The hydrocarbons to be drilled are part of the property of landowners. That implies that if drilling starts those suffering from disruptions were also those benefiting. And finally, a competitive and dynamic service industry, including financial capital, was in place to help operations, which were run by a relatively large number of smaller independent companies. Only recently have large international oil companies started to buy themselves into the market, with the apparent objective of studying the technology and applying it in other parts of the world.

imports from Canada were hit, whilst those from Mexico disappeared altogether.

3.3 Outlook for the US gas market

3.3.1 Outlook until 2018

The shale gas revolution is a game changer in the US natural gas market. The patterns of production, consumption and trade have fundamentally changed. The sudden shale gas glut has pushed up gas consumption in the power sector as the first signs of gas exports from the US become visible. This raises the question of whether the growth in shale gas production can continue.

To answer this question we need to take a closer look at recent market conditions. Henry Hub prices reached an average of USD 2.75 per MBtu in 2012, hitting a low of just below USD 2 during April of that year. That was below the marginal costs of some wells and clearly well below the level of USD 4 per MBtu that is often taken as the benchmark for healthy production. From 2012's low, the price rose to USD 4 per MBtu in early 2013, and then fell back slightly to USD 3.75.

However, low prices have not stopped the boom in production. There are a number of reasons.[8] Firstly, the financial time horizon for shale gas is less than five years: a period in which futures markets and over-the-counter derivatives are sufficiently liquid. This allows hedging opportunities against price declines for producers, and these opportunities are reportedly used routinely. Secondly, there are still ample possibilities for production efficiency improvements, with operating companies reportedly reducing production time by 40% and costs by as much as 14%. Technological developments such as multistage hydraulic fracturing and improvements in how fracturing is used also helped. The number of rigs has been dramatically reduced: from 790 in early 2012 to 370 in April 2013. Thirdly, shale gas is produced alongside liquids that provide higher profits.[9] Firms are therefore able to survive, and even be profitable, at very low gas prices. That explains

[8] IEA (2013), Gas Medium-Term Market Report 2013: Market Trends and Projections to 2018.

[9] For example prices of ethane, propane, butanes and pentanes have been relatively high, showing a strong correlation with the crude oil price.

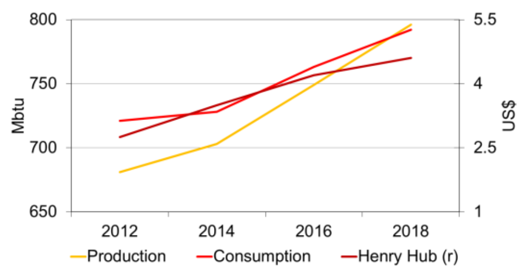
much of the absence of an impact of low prices on production growth. Moreover, prices are expected to firm up, gradually, to USD 4.6 per MBtu in 2018.[10]

This suggests that continuation of the shale gas boom is likely. There are also qualitative arguments to underpin this expectation: consumption is likely to pick up and (potential) infrastructural bottlenecks are being addressed, as we will now discuss.

Consumption is likely to pick up for a number of reasons. Firstly, as 2013 has already shown, future winters are unlikely to be as mild as that of 2012. This means that consumption in the residential and commercial sector will generally be higher than in 2012. Secondly, as economic growth in the US gathers pace, industrial sector consumption will strengthen, helped by the still relatively low prices. Thirdly, and in particular, the consumption of gas in the power sector is expected to continue to grow. Indeed, 'The Switch' from coal to gas-fired power plants is not expected to expand much further at these prices. But stringent new rules on carbon emission as from 2015 will change this picture: gas-fired stations typically emit only half the volume of carbon dioxide per unit, as coal. Furthermore, according to the Federal Energy Regulatory Commission, the closure of coal-fired power stations will accelerate and the increasing use of renewable energy sources will require more back up by natural gas plants. This supports future gas consumption.

Infrastructural bottlenecks are being addressed in two ways, allowing exports to increase. Firstly, investments in pipeline construction can be expected to support production growth. According to the IEA, around 315 bcm of natural gas pipeline capacity is at some stage of proposed or planned development, to be completed by 2016.[11] This will allow exports to Mexico and Canada to develop.[12] Secondly, with imports shrinking as the shale gas production proliferated, LNG import capacity became idle; in 2012 only 5 bcm of LNG was imported compared to an import capacity of 192 bcm per year (2.5%). With the prospect of LNG exports higher as the shale boom develops, adjusted import facilities and new LNG export facilities are being considered. This represents 300 bcm per year export capacity (40% of current US production). Export approvals of 27.2 bcm have been obtained for two projects (Cheniere in Texas and Sabine Pass in Louisiana).

Chart 3.6 US gas market 2012-2018
(Forecast)



Source: IEA

In these market circumstances the IEA expects US natural gas production to grow by almost 17% over the outlook period to 2018 (1.9% per annum, see Chart 3.6). Shale gas production and, to a lesser extent, tight gas, lead the production growth, while conventional gas production is expected to continue to decline. Consumption is projected to grow by almost 10% over the outlook period (1.6% per annum). This growth will be led by the power sector (up 10%) and industrial sector (up 7%), for the reasons discussed above. IEA projections will therefore suggest natural gas self-sufficiency for the US by the end of the outlook period. This is a net figure: in 2018 exports are projected to have doubled, while imports will continue to shrink and end up 15-20% lower than in 2012 (88 bcm). Meanwhile, LNG exports from the US are uncertain and not included in these projections.

3.3.2 Outlook until 2035

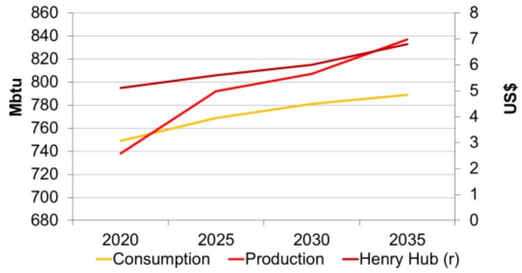
The outlook until 2018 shows that the shale gas revolution and its impact is expected to persist throughout that period. The impact should be a quite low gas price, a spur to domestic demand from the power sector and, to a lesser extent, the industrial sector, and net exports starting to gather pace. For the period up to 2035 that also holds true, although the level of uncertainty about the forecasts understandably rises. Chart

[10] IEA (2013).
[11] For some perspective of this capacity increase: the total natural gas production in the US in 2012 was 681 bcm.
[12] This will gradually solve the unhealthy situation in the market where large volumes of natural gas are to be rejected because of lack of transport capacity.

3.7 summarises the expected market development over the forecast period.[13]

The forecast implies that the increase, since 2011, in US production will be 200 bcm in 2035 (1.1% growth per annum on average). Unconventional gas production will have grown, by 280 bcm, of which almost 75% will be shale gas, indicating that the shale gas revolution is expected to continue. As consumption will increase by just 100 bcm (0.5% per annum), net exports will reach a volume of 50 bcm per annum. The Henry Hub price is expected to leap up, to USD 6.8 per MBtu in real terms, as exports, especially to Asia, tighten domestic supply. This picture is supported by a number of arguments.

Chart 3.7 US Gas Market 2020-2035
(Forecasts)



Source: IEA

Firstly, there are ample reserves of unconventional gas in the US, with a recent estimate indicating that technically recoverable reserves are in a range of 115 years at 2011 production levels. This suggests that there is little limitation on the resource side.

Secondly, on the demand side the main driver will remain the electricity sector. Whereas the dominance of 'The Switch' will fade over time, the preference for gas for new thermal generation will push up demand. As we have argued above, what underlies this are environmental concerns about the scope for using coal. Far less prominent, but still of note, is the contribution of the transport sector as it switches from petrol to electricity (for which gas is needed).

Thirdly, the price increase to USD 6.5 per MBtu in 2035 is a level where production is profitable, as we have already discussed above. At the projected consumption levels, for these prices to be sustainable US exports will have to increase on the back of higher prices elsewhere in the world. This is indeed what is expected as will be discussed later in this report.

Risks to this outlook are arguably balanced. On the one hand, the generally favourable regulatory and operating environment for unconventional gas that we have described earlier could change on the back of a shift in public opinion, such as potential concerns about drinking water, ground water and small earthquakes.[14] States have a large degree of freedom to set regulations, and indeed there is a wide variety to be detected, with some states such as New Jersey and New York (temporarily) banning hydraulic fracturing. On the other hand, there may be another revolution on the horizon. The US Geological Survey has estimated that methane hydrates may be 10 to 100 times as plentiful as US shale gas reserves. Methane hydrates are found beneath the sea floor or beneath Arctic permafrost. Some small scale projects are underway, but technology is still in its infancy and there are considerable environmental issues to be addressed, such as the greenhouse gas impact of omissions. However, if this proves viable, production may start in mid-2020.[15]

Return to contents page

[13] We have opted here for IEA (2014) projections as these are (at last in absolute figures) consistent with the previous figures presented.

[14] The US Environmental Protection Agency is preparing a report due in 2014.

[15] See for info http://www.netl.doe.gov/technologies/oil s/FutureSupply/MethaneHydrates/maincontent.htm.

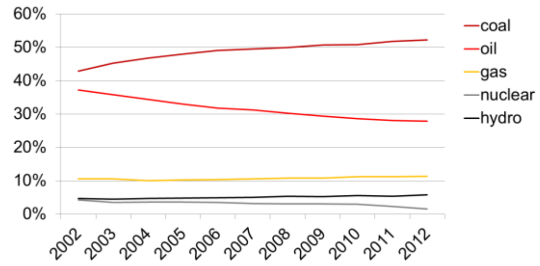
Part 4 – Asia

In this part we take a closer look at the developments on the Asian gas market. We observe that the share of gas in the energy mix is still more limited than in the US, reflecting the importance of coal in the emerging parts of Asia, particularly China and India. As these economies continue to thrive and environmental issues come more to the forefront, the share of natural gas is expected to increase significantly. That will put further pressure on the gas supply deficit that has emerged during the past decade. So far that deficit has been met primarily by LNG imports: an expensive process but one necessitated by the large distance between consumer and producer countries. The regional gas price increased fourfold between 2000 and 2013, and is by far the world's highest regional price. This has triggered a flurry of investments in LNG facilities, particularly in Asia. Indeed, continued growth in consumption should be largely met by LNG imports. In addition, Chinese non-conventional gas production should start to relieve upward pressure on prices. Indeed, if that materialises and the cost of LNG can be contained, future prices can be expected to remain around the current levels in real terms.

4.1 The importance of gas in the Asian energy mix

Over the past two decades we have seen a slow rise in the relative importance of gas in the Asian energy mix. Gas constituted only 6% of total energy demand in 1990, but rose to 10% in 2011. For the relatively poor emerging countries in Asia these figures were lower, 3% and 8% respectively, but the rise was steeper.

Chart 4.1 Energy mix in Asia
(Percent of total demand)

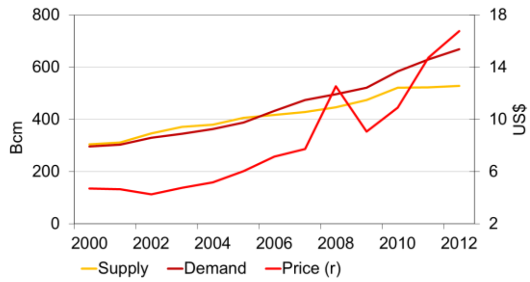


Source: BP Statistics

4.2 Rapid growth in demand has created a supply deficit

There has been a rapid increase in demand in Asia, driven by its emerging countries: China, India and the countries of South East Asia. In Asia's developed economies of Japan, South Korea and Taiwan demand has risen from 311 bcm per annum to almost 664 bcm per annum between 2000 and 2012: an average annual increase of 9.5%. But in emerging Asia, demand has risen from 180 bcm to 286 bcm: an increase of 12% per annum. Production in Asia kept pace with demand until 2006, after which imports had to fill the gap. In line with these developments, prices have risen sharply over the period: from USD 4 MBtu in 2000 to USD 16.5 MBtu in 2012. We will now provide more details of gas demand and supply and, in the next section, the picture of imports.

Chart 4.2 Gas market Asia-Pacific
(Supply, demand, prices)

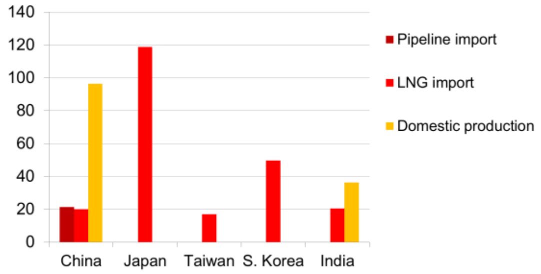


Source: IEA

The main consumer countries in this region are China, India, Japan, Taiwan and South Korea. Rapid demand growth in China and India (and the rest of emerging Asia) is due not only to the high economic growth rates in the emerging Asian countries but also to a switch from lignite (brown coal) and coal fired power generation to natural gas. China's largest cities experience suffocating concentrations of smog, so that air pollution has become a key issue. Since gas combustion produces less smog than coal or lignite combustion, gas is expected to become a more important energy source. Japan's demand for natural gas increased after the Fukuyama nuclear disaster in 2011 but has remained stable since.

As in the US, power generation is the most important application of natural gas in Asia, constituting 51% of total demand in 2012. The industrial and heating (residential and commercial) sectors account for 24% and 14% respectively and these percentages have been relatively stable since 2000. Japan stands out: the use of natural gas is even more skewed towards power generation (63%). Industry and residential use in Japan account for 9% and 29% respectively. For emerging Asia, the figures vary, with a much lower share in the power sector at 44%, industrial 29% and heating 6%: again, figures that have remained relatively stable since 2000.

Chart 4.3 Import versus domestic production
(In Bcm)



Source: IEA

Though insufficient to meet the rapidly expanding demand, natural gas production in the Asia-Pacific region has increased steadily over the past decade. The major producers in the Far East are China, Indonesia and Malaysia. Except for China, the domestic production of natural gas in the main consumer countries (China, India, Japan, South Korea and Taiwan) is very limited, so that these countries are highly dependent on gas imports. Besides pipelines, LNG plays a very important role in these imports.

4.3 The supply deficit is primarily met by LNG trade

As already mentioned, most gas imports are supplied as LNG, and it is growing in importance, accounting for 83% of all imports of gas, with the rest delivered by pipeline (so called 'dry gas').

Box 2 The essentials of Liquid Natural Gas

When natural gas is exploited it is, obviously, found in gas form. Its energy intensity per volume unit is many times lower than that of oil. This means that transport costs for gas are high and only feasible when delivered by pipeline. An alternative was found in 1914: natural gas could be liquefied by subjecting it to very low temperatures (ca. -162° C). The gas turns liquid which enormously increases its energy intensity per cubic metre. LNG has an energy intensity of approximately 60% of diesel. First the natural gas is purified by removing contaminants like water, dust, acid gases and helium. Then the gas is cooled. The liquid natural gas (LNG) is then put into specially designed cryogenic vessels, shipped to the destination, pumped ashore where it is regasified in specially designed regasification terminals. Then the natural gas is distributed by pipelines to the end consumers. This is, not surprisingly, a very expensive technology.

For example, the planned expansion of the Tangguh LNG terminal in Indonesia has an estimated cost of USD 11 billion. The complementary regasification terminal will cost an estimated USD 1 billion, while the required cryogenic vessels cost around USD 250 million each. A breakdown of the different cost components of LNG (per 1 MBtu) is as follows: USD 3 to USD 4.50 for the liquefaction process; USD 0.60 to US 3.50 for shipping (dependent on the distance) and USD 0.30 to USD 0.50 for the regasification process. The first commercial LNG plant was built in 1917 in the US, but international trade in LNG did not begin until 1964. In that year a major LNG plant was built in Algeria to serve the French and Italian markets. In 1972 a LNG plant in Brunei was opened and many others in Asia-Pacific would follow during the 1980s and 1990s.

The main suppliers of LNG to the Far East are the Gulf countries (especially Qatar), Malaysia, Australia and Indonesia, while the main suppliers of dry gas are Turkmenistan (pipeline to China), Indonesia (pipeline to Malaysia and Singapore) and Myanmar (pipeline to Thailand). Currently China, Japan and Korea together import 210 bcm of natural gas annually. Of this almost 90% consists of LNG, due to their geographical remoteness, which rules out transport by pipeline, and their relatively high energy consumption. China, and to a lesser extent India, are now also large buyers, because of their size and rapid economic development, and China also produces a considerable volume locally.

As well as the high cost of LNG, the timescale for the construction of these plants is around 10 years. Nevertheless, LNG exports to Asia are still highly profitable at the current high price in the region. Investment in LNG facilities has increased rapidly: in 2013, 360 bcm of LNG facilities were in operation worldwide (2000: 138 bcm), with 138 bcm under construction and 870 bcm under consideration.

Besides the current suppliers mentioned above, East Africa (Mozambique, Tanzania), the US and Canada are potential future suppliers of LNG to Asia. Exports from the US will stem largely from the Gulf of Mexico, where the infrastructure is already in place. Gas can be pumped to the LNG ports in Texas and Louisiana, then shipped through the Gulf of Mexico, the Panama Canal and the Pacific to markets in the Far East. Canada is logistically well placed too. Gas exploration is under way in British Columbia, which will allow shipping from ports on the Pacific coast into Asia.

Currently the cost of producing and shipping one MBtu of natural gas from the US to Japan is estimated to be USD 9, giving a profit of USD 6 per MBtu. With a rise in the Henry Hub price and increased competition in LNG, this profit is expected to decrease to USD 4.30 per MBtu in 2020. The route from East Africa, through the Indian Ocean, is shorter. However, the development of gas fields and liquefying equipment in this region is still in an early phase. The difficult business environment in Mozambique and Tanzania may discourage vital foreign direct investment. In 2013 one major new export facility came on stream: Angola LNG. While the US was originally expected to be the buyer, this is no longer feasible and the facility has started to supply Asian markets instead. Currently there are still twelve LNG terminals under construction - seven in Australia with a capacity of 83 bcm intended for export to Asian markets. Another is in Papua New Guinea (9 bcm). This terminal starts production in 2014 and will mainly supply Japanese and Chinese utilities. The others are being built in the US (24 bcm) and are also intended mainly for the Asian markets. Projects in other parts of the world, including Africa, are under consideration, but are not yet under construction.

The flurry of new LNG capacity under construction has pushed up costs, especially in Australia, where the labour is scarce. Increasing fuel and material costs and a strong Australian dollar are compounding the situation. For one of the projects - Gorgon - the cost has been revised from USD 37 billion to USD 52 billion (a 40% increase): a worrying omen for future projects.

4.4 Oil indexation and long term contracts still the norm

Gas trade is dominated by long-term contracts and relatively high prices, the reasons for which we have already briefly mentioned. Although Asia has a number of very large economies, natural gas reserves in the region are small. Geo-strategic considerations also play a role, so that countries are prepared to pay a premium for reliable gas supplies if this makes them (ostensibly) less dependent on developments abroad.

As we have seen earlier in this report, the prices of natural gas were traditionally indexed to the price of oil, and this still largely holds in Asia. A typical gas price formula in Asia would look like this:

$$P_g = b + a * P_o$$

… where P_g is the price of gas (per MBtu), and P_o the oil price per barrel (with Brent as the usual benchmark). The parameter *a* is typically set at 0.15. The term *b* reflects transport costs and is typically set between USD 0.60 and USD 3.50 (dependent on distance). A floor and a cap are often agreed in the price formula, to protect both producers and buyers from excessive movements in the oil price. Applying the above formula with today's oil price, we arrive at a gas price of (0.15 * USD 109 + USD 0.6) USD 16.7 per MBtu for

LNG supplied by Australia to Japan. This is by far the highest price of the three major global natural gas markets.

Currently gas contracts are almost always long-term contracts. However, spot market purchases are on the rise, as we have already seen, and this has been helped by developments in Japan. After the closure of its nuclear power stations, Japan had to buy significant quantities of natural gas to satisfy the sudden increase in demand. The spot market was the natural place to turn to. Apart from unusual circumstances like these, more spot trade could come from the creation of an LNG hub in the region and would be a major step towards market liberalisation in Asia. The establishment of such a hub would signal the will of the respective governments to allow increased competition and the surrender of control of a sector considered to be of strategic importance. However, this is something that many Asian governments would find difficult to do although, if it goes this way, Singapore is the most likely candidate to establish a gas hub in the medium term as it is the most economically liberal country in the region, already has a reputation as a trade and transport hub, and perhaps because it is less preoccupied with security issues than other Asian countries like China and Japan.

4.5 Outlook for the Asian gas market

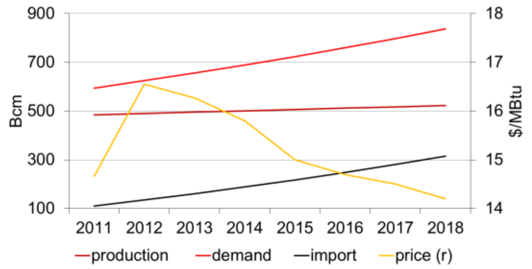
4.5.1 Outlook until 2018

Although the relative importance of natural gas in the total Asian energy mix will rise only slightly (from 10% of the total energy demand in 2011 to 11% in 2020), this translates into a substantial increase in volume: total natural gas demand in Asia will rise from 483 bcm in 2012 to 576 bcm in 2018 (20% increase).

Demand for energy in the developed countries of Japan, South Korea and Taiwan is expected to show a similar pattern as OECD countries in the West: i.e. rather flat demand. Even Japan's gas demand is expected to remain stable in the coming years, in spite of talk of phasing out nuclear energy. Indeed, under the current economic policy of prime minister Abe, a shift away from nuclear energy has become much less likely. 'Abenomics', as the policy has come to be known, includes a driving up of inflation and depreciation of the currency, resulting in higher prices for imported energy. As a result, the resumption of nuclear energy usage has become a much more economically attractive proposition, making the previously announced closure of nuclear power stations less likely to happen. Demand in emerging Asia will rise from 286 bcm in 2012 to 360 bcm in 2018 (a 26% increase), due largely to increasing demand from China and India, where ongoing high economic growth will push electricity demand and therefore demand for natural gas.

Production of natural gas is likely to increase in China, where shale gas production is expected to take off. However, as mentioned above, there is a high degree of uncertainty and production is not expected to keep up with demand, in spite of the huge reserves. Asian production (emerging plus developed) is expected to increase to 385 bcm in 2018 (2012: 337), which leaves a gap of 191 bcm, up from 146 bcm from 2012, to be filled by imports. Again, these imports will be primarily through LNG.

Chart 4.4 Asian gas market outlook
(Production, demand, prices)



Source: Atradius Economic Research, BP, World Bank

About half of the import needs will be supplied by Oceania (mainly Australia), leaving the Middle East, East Africa and the US to provide the rest. Between now and 2017 12 LNG plants will be commissioned and another 23 are planned or under consideration for the period up to 2020. In the Middle East, Qatar will remain a major LNG exporter due to the large increase of domestic energy consumption in the Gulf states. This leaves East Africa and, to a lesser extent, the US as future suppliers of LNG to Asia.

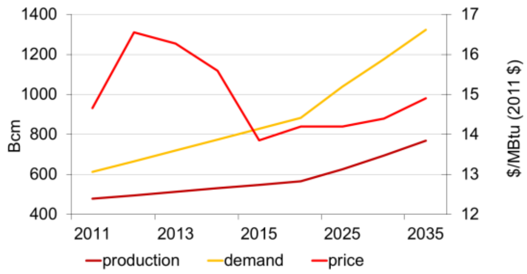
In particular, the increase in imports of LNG from the US could have a significant impact on the pricing mechanism of LNG in Asia. In several LNG contracts, international oil firms have signed Henry Hub-linked arrangements with Asian buyers, although a complete switch to hub-based indexation is not likely, and, certainly not in the short term. However, a gradual transformation from pure oil-based indexation to a system of hybrid indexation seems likely in the long term, which would lead to a fall in the gas price in Asia. Moreover, the growing number of suppliers of LNG also has the potential to undermine the oil indexation mechanism. The price forecasts for LNG in the Japanese market reflect the partial convergence with the American gas market up to 2015. Up to 2018 the price is expected to increase slightly in real terms.

4.5.2 Outlook until 2035

In the long term, i.e. up to 2035, the trend described above will be even more pronounced. Total natural gas demand will rise to around 1,324 bcm in 2035 with growth largely attributable to emerging Asia: in particular China. Demand in developed Asia will remain fairly stable.

Gas production in the whole of Asia in 2035 is forecast to be 769 bcm annually, indicating that there will be a shortfall of 555 bcm per year to be filled by imports. The main suppliers will then be the Middle East, Oceania and especially Africa. As the following chart shows, gas demand will accelerate from 2020 and import needs will increase. This will put upward pressure on the gas price. Nevertheless, the upwards effect on the gas price will be limited, since several developments will put downward pressure on that price in the long term: increased exports from the US, the creation of a gas hub in Asia resulting in a partial exit from oil indexation, and technical progress in LNG production. In particular, the liquefaction process could become less expensive due to floating LNG plants.

Chart 4.5 Future gas market in Asia
(Production and demand forecasts)



Source: IEA

As to China, the increasing dependency on imports is even more pronounced: China currently imports 15% of its gas needs, but by 2035 this is expected to be 40%, in spite of the large increase in gas production that is supposed to take place in China. Production is forecast to increase from 109 bcm in 2012 to 317 bcm in 2035. This growth in production is due to the anticipated exploration of shale gas, of which China is the world's largest holder. The exploration of these shale gas reserves might, however, prove to be difficult due to the location of the gas fields. Exploration of shale gas needs huge amounts of water to be pumped into the gas containing rocks, while the shale gas reserves are located mainly in deserts and dry areas. Even if Chinese shale gas production were successful, the expected future production implies an import need of 212 bcm per annum.

The development of Chinese production is arguably the largest uncertainty to the outlook for 2035. If Chinese shale gas production does not happen, or at least in the volumes expected, this will clearly create further upward pressure on the Asian gas price. As such, this would be beneficial to LNG projects, allowing room for the expected cost increases, and clearly US exports would be more attractive. But these secondary effects may not be sufficient to relieve the upward price pressure.

Return to contents page

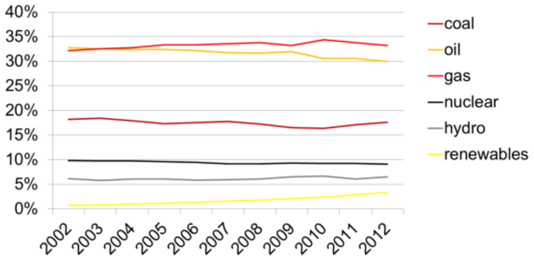
Part 5 – Europe

This part addresses the European gas market and demonstrates that it has a number of peculiarities. The first one is the still dominant link of the gas price to the oil price, causing the price to increase even when demand and supply hardly change. The second is the focus on environmental issues, which has led to a European emissions trading system (ETS) and a renewable energy policy in Germany. However, because ETS does not work well while the German renewable energy policy does, together they have led to the unintended consequence of higher coal consumption and lower gas use - despite the fact that coal is a much more polluting energy source. This has been recognised, but a lack of political will still dominates and will prevent gas demand from regaining its lost ground. There will be a modest improvement in demand, however, as the economic crisis ebbs and is replaced by cautious economic growth. As production gradually declines in Western Europe, there will be upward pressure on gas prices and more market based pricing - rather than oil price linked. The main supplier, Russia, is expected to benefit from this situation, although commercial and political reasons will push European countries to search for diversification of supplies. To this end, LNG, even from the US, might play a role in due course.

5.1 Gas is dominant in the European energy mix

In the European Union's energy mix, gas surpassed oil as the dominant energy source in 2000. Until 2010 gas maintained a stable share of around 33%, although that percentage has declined since 2010. Oil has seen a sharper decline, while the importance of coal and renewables has risen. We will discuss these developments in more detail below.

Chart 5.1 Energy mix in Europe
(Percent of total demand)



Source: BP Statistics

5.2 Weaker market conditions

The most important European sector in terms of gas consumption is the residential/buildings sector, which accounted for 40% of total consumption in 2012. This was followed by industry (23%) and power generation (31%). For residential/building, this figure has been stable since 2000, while the share of consumption has risen for power generation (from 23% in 2000) and declined for industry (29% in 2000). The large share achieved by residential/building explains the volatility in European gas demand. Cold winters increase gas demand for heating homes and offices while mild winters lead to significantly lower demand. With this in mind we can explore the developments in the European gas market.

The overall picture is one of a gradual decline in production, with consumption being more or less constant since 2000, but declining since 2010. However, prices have gone up and therefore do not reflect changes in supply and demand. The explanation is the strong link with the oil price. In line with the oil price the gas price increased steadily between 2000 and 2008 and, also in line, decreased in 2009 and 2010.[16]

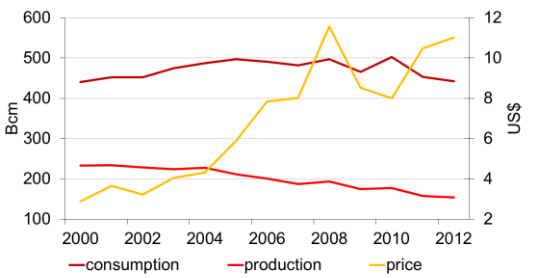
Notably, production declined in the UK, France, Germany and Italy, from 156 bcm in 2000 to 63

[16] The leading price for continental Europe is the average German import price. This is the average price for gas at the German border.

bcm in 2012, as gas wells were being depleted. The counterbalance to this was Norway, with an increase of 62 bcm over the period, leading to an overall decline in European production by 33 bcm to 277 bcm in 2012. Demand stood at 513 bcm, highlighting the case for imports, to be discussed in the next section.

As for demand, the largest consumers in Europe are, perhaps unsurprisingly, the larger countries: Russia, the UK, Germany and Italy. Consumption has declined sharply in these markets, particularly in Germany: overall consumption in 2012 was on a par with 2003. The increase in consumption in 2010 was due to the cold weather that year, but a relatively mild winter in 2011 offset the previous increase. Weak economic growth and relatively high gas prices are the main reasons for this feeble demand in Europe. This weak demand for gas has been aggravated by the low coal prices combined with low prices for carbon dioxide and the big spur in renewable energy, especially in Germany. These issues will be discussed below.

Chart 5.2 European gas market
(Price = average German import price)



Source: BP Statistics

In 2012 the sharpest drop in demand was in the power sector: a 17% year-on-year decline. Although coal is more polluting than gas, its use in the European power sector has increased in recent years as it is cheaper than gas for electricity production. The low gas prices in the US resulted in a major switch from coal to gas in the US power sector, as discussed in Part 3. The oversupply of coal in the US resulted in a decrease in coal prices and an increase in exports to Europe. Moreover, CO_2 prices are low due to flaws in the design of the European Emission Trading System (ETS) and the weak economic situation, which have led to an unanticipated decline in emissions and a surplus of allowances. Carbon prices have consequently decreased,, reaching levels unsustainable to stimulate investments in low-carbon technologies. In mid-2008 the carbon price was EUR 30/tonne, but the price dropped to less than EUR 3/tonne in April 2013. Although it is clear that the ETS system has not achieved its objectives, there is still insufficient political support for a change. Fuel switching in Europe depends on the interaction between the prices of coal, gas and CO_2. As long as the CO_2 prices remain this low there is no incentive to switch to gas.

5.3 Renewable energy boom in Germany

With a share of 23% in total pipeline imports, the developments in Germany are quite important for Europe and are also disturbing the market somewhat. In 2000 Germany introduced the Energiewende: the transition to green energy from fossil fuels. To encourage this transition, Germany set guaranteed high tariffs for power generated from renewable sources, and thus for producers, for 20 years. In 2010 a new policy was introduced with a target of 80% of total electricity to come from renewable sources in 2050. Moreover, the closure of nuclear plants has been ordered: the latest in 2022. Subsidies have accelerated the use of solar, wind and biomass energy and renewable energy sources have priority access to the electricity grid, ahead of traditional sources. These policies have led to a boom in wind, sun and other sources of renewable energy, and these resources now account for around 23% of electricity consumption, compared to just 5% in 1999.

The energy glut from renewable energy is also creating some challenges. There are regional imbalances: in northern Germany a supply surplus, in the south a supply deficit. The existing network infrastructure has insufficient capacity to transfer supply from the wind farms in the north to the large industrial areas in the south. Germany has had to use the grid of neighbouring countries to transport the energy supply to the south. But those neighbours are increasingly complaining about this, as it is blocking their networks, with some even installing special equipment at the border to prevent German power overtaking their own. Therefore, Germany needs to upgrade its transport infrastructure to cope with the increasing use of renewable energy. Another challenge is that renewable energy can never replace fossil fuels on a one-to-one basis, because on cloudy and windless days back-up is needed. However, this back-up is far from a green solution. Germany's decision in 2010 to phase out nuclear plants resulted in a rise in coal power generation. And it isn't just Germany: other countries in Europe have increased their use of coal plants due to the relatively high gas prices compared to cheap coal from the US.

It actually turns out that the green revolution in Germany is proving quite disastrous for utilities and households. For utilities, investments in gas-powered plants have not turned out to be profitable. Gas power plants are cleaner than coal power plants, but they are more expensive to build. And households are faced with some of the highest energy bills in Europe. The difference between the market price of energy and the high fixed price of renewables is being passed to consumers. About half of their energy bill is attributed to subsidies and taxes, compounded by the exemptions afforded to industrial companies to help them stay internationally competitive. In 2013 the total cost of subsidies was USD 16 billion. It appears that, with current technologies, wind and solar are more expensive energy sources than gas, oil and coal.

What we have so far discussed is characteristic of the European energy situation. The vision was that gas would complement wind as a variable sustainable energy system backed up by gas fired power. The ETS system would, by increasing the costs of pollution, ensure a transition to a low CO_2 environment. However, in reality gas fired power production has decreased in recent years and coal fired power production has increased, because the price of the combination of coal and CO_2 emissions is currently lower than that of gas for producing electricity. The transition to more renewables has led to wind reducing the role of gas in power generation. However, the combination of lower coal prices and low prices for carbon has aggravated this decline and resulted in wind being complemented by coal-fired power. This combination of wind and coal emits more CO_2 than the combination of wind and gas. Even worse, it is emitting more CO_2, and is

Box 3 European Emission Trading System

The EU ETS was launched in 2005 and is the world's largest emission trading scheme, including all member states of the European Union and Norway, Iceland and Liechtenstein. It covers around three-quarters of international carbon trading. It was introduced to cut the emissions of carbon dioxide (CO_2) and other greenhouse gases, providing incentives to invest in low-carbon technologies. It is a trading system for energy-intensive industry, power stations and commercial airlines flying within or between the countries covered. For companies operating in these sectors participation is mandatory, but some small companies may be excluded. There is an annual limit on overall emissions. This limit is reduced every year and, within this limit, companies receive (from their governments) or buy and sell emission allowances.

An emission allowance gives the holder the right to emit one tonne of CO_2, which can be used only once. Companies have to 'pay' an emission allowance for every tonne of CO_2 they emit. They can buy such allowances or draw on their saved allowances from previous years. The EU has a target of reducing emissions by 20% in 2020. Since 2013 the main method of allocating these allowances is by auction (mainly for the power sector) whereas, in the past, governments would give them away freely. The market price of allowances is the so called 'carbon price' and is determined by supply and demand. If the price is high it should give more incentive to invest in technologies to cut emissions.

even more expensive, than gas alone. Ironically, Energiewende has actually led to an increase in emissions of greenhouse gases.

5.4 Trade

With production declining in the region, the countries of the European Union are becoming more dependent on imported gas. The most important exporters to the European Union are Russia and Norway, while the Netherlands is an important exporter to other European markets. Most trade is by pipeline and, of the total European imports by pipeline, Russia contributes almost 35%, Norway 28%, Netherlands 15% and Algeria 9%. There is some trade in LNG, but this is small compared to pipeline. In 2012 LNG accounted for only 18% of gas net imports from non-EU suppliers, down from 24% in 2011. That drop was due to declining gas demand in Europe, but also high demand for LNG in Japan at higher prices than in Europe. LNG exporters to Europe are Qatar, Algeria and Nigeria, with Qatar by far the most important, contributing around 45% of total LNG supply to Europe in 2012.

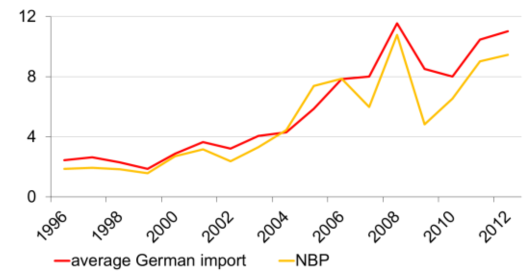
Its reliance on a few suppliers is causing uncertainties about Europe's security of supply, especially as EU production is expected to decline in the medium to long term and its reliance on gas imports to increase. As mentioned, the most important suppliers are Russia (Gazprom), Norway (Statoil) and Algeria (Sonatrach) but Europe is trying to diversify its gas supplies. There is sufficient import capacity in Europe. Both pipeline infrastructure and LNG regasification terminals are either built or under construction: enough to allow for diversified gas supply. In the Caspian region new pipelines are planned to reduce dependence on Russia and allow imports from, for instance, Azerbaijan and Turkmenistan.

5.5 Price mechanism

Gas in Europe is traditionally indexed to oil product prices. This so-called reference price mechanism has its origin in the 1960s in the Netherlands, when the Groningen gas fields (then the largest gas field in the world) were exploited. However, since 2009 European gas importers have been less willing to pay the relatively high gas prices. In Germany some major gas importers have taken Gazprom to arbitration to break or change the link of oil-indexation in contracts.

The main indices for gas prices in Europe (including the UK) are the National Balancing Point (NBP) and the German border price. Although, traditionally, the German border price was seen as a reference for the oil-indexed price, this has changed slightly in the past two years. Nowadays, it is an average of oil-indexed supplies and spot gas supplies from the Dutch border and Norwegian pipeline. This could also explain why the average German import price has not increased more in line with the oil price.

Chart 5.3 European gas prices
(US$ per million Btu)



Source: BP Statistics

Most contracts have a long tenure and these are mainly oil-indexed, but there is increasing trade via gas hubs where supply and demand are determining the price. Examples of these virtual trading hubs are the British NBP - the largest in Europe - and the Title Transfer Facility (TTF) in the Netherlands – the second largest. The NBP is the oldest trading point and is considered by the gas industry to be the most mature in Europe. It started in the mid-1990s and has a strong influence on continental hubs through the connection to two gas lines. NBP is a liquid and transparent market and also has a futures market. TFF and Zeebrugge are the most mature hubs in continental Europe. More gas hubs have been established to encourage trade based on spot prices. These spot markets have been established mainly in North West Europe, as the conditions are more suitable there.

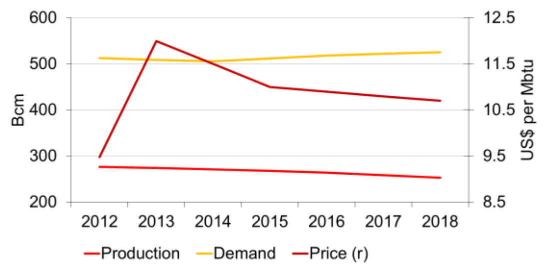
Long-term contracts typically have a tenor of 20 years. This creates security of supply for consumers and security of demand for the suppliers, and also pays for the use of the infrastructure. It creates an obligation on the seller to provide defined volumes of gas and on the buyer to buy a minimum volume secured by a 'take-or-pay' commitment (i.e. having to pay a penalty when not taking the minimum agreed volume). Most contracts have a price review clause, meaning that both parties can renegotiate the price periodically (in general once every three years) when there have been changes in prices of competitive fuels, technology and/or in market share of alternative fuels basis. There are variations in the price formula across and within regions. Weak demand in Europe, surplus supply and the availability of LNG at competitive prices put the system of long-term contracts with oil-indexation under pressure. Due to weakening demand, some exporters have given a discount in their on-going contracts or sold gas at lower prices at European gas trading hubs. According to the international Gas Union, the share of gas sold under oil indexation has decreased to around 60% of the total gas sold - the remainder being on the basis of gas-to-gas competition.

5.6 Outlook for the European gas market

5.6.1 Outlook until 2018

The situation in Europe remains different from the rest of the world. Production is expected to gradually decline in the short term, but also in the medium to longer term. Although Norway will continue to increase production, it will not be able to offset the declining trend in the Netherlands (especially after 2020) and other wells in the North Sea. The decline in conventional gas production is expected to be only modestly mitigated by a rise in unconventional gas production. The development of shale gas is highly uncertain in Europe, for instance because of environmental concerns and high population density. The results of exploration testing in Poland were quite disappointing and resulted in a scaling back of the technical recoverable reserves. This led several companies to withdraw from further exploration.

Chart 5.4 Medium term outlook EU
(Forecasts)



Source: World Bank, IEA

Russia is an important producer in Europe and its production is expected to increase over this period. Weak demand from Europe is limiting export opportunities for Russia in the short to medium term and this has recently led to Russia turning to Asia-Pacific markets. However, large investments have to be made as, although there are ample resources in Eastern Siberia, it is a remote region. To diversify its export destinations, Russia is considering expanding its LNG capacity.

The outlook for European demand in 2014 and 2015 also remains quite weak and uncertain, with demand not expected to increase until 2016, and then only gradually, in line with the pace of Europe's economic recovery. As explained above, demand in Europe also depends on the development of the prices of coal and CO_2. When coal prices rise, the use of coal in Europe as a back-up is less attractive for the power sector. Such an effect could be reinforced by an expected increase in the price of carbon due to new environmental measures (a revision of ETS).

In Europe the trend towards hub-based pricing is expected to continue, with more use of short term contracts. But large suppliers like Gazprom and Sonatrach will voice strong opposition to this, as the necessary investment in gas infrastructure in Europe and Russia is costly. This investment, in new infrastructure to reach export destinations will create a baseline for gas prices in Europe (around USD 8 à 10 per MBtu). Most investments will take place only when off takers are known in advance and therefore long-term contracts will be needed. In the short term it is expected that the price of gas will decline marginally.

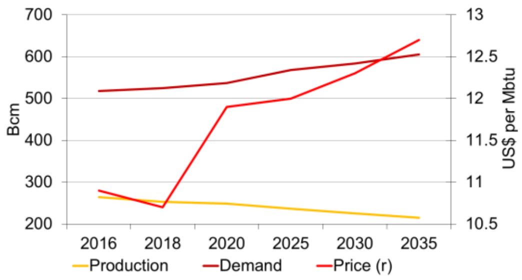
5.6.2 Outlook until 2035

Increasing demand from 2016 onwards will put upward pressure on gas prices in Europe, with higher economic growth contributing to higher demand. Production will continue to decline in Europe in the period up to 2035, especially in the Netherlands after 2020. Therefore, Europe will become more import dependent over time, resulting in a gradual increase in the gas price. Russia is expected to benefit from rising European demand, with a consequent increase in Russian production. However, the Crimean - and more broadly the Ukraine - crisis could lead to Europe looking for other gas suppliers. In 2013 Gazprom supplied 30% of European gas and, while this will not change in the short term, over the longer term Europe could find the political will to reduce its dependency on Russian gas, especially as US LNG exports progress.

There are several uncertainties for the price outlook in the longer term. Policy measures about, for example, the environment and security of supply, can change the use of energy sources. A reform of the EU ETS is inevitable in the longer term as the surplus of allowances is currently disturbing the market and the low prices are no incentive to invest in emission-saving technologies. In the medium term higher carbon prices will eventually make coal-fired power plants less attractive. The IEA expects that the prices for carbon will increase from USD 6 per tonne in 2013 to USD 20 per tonne in 2020 and USD 40 per tonne by 2035.

In the longer term, European legislation concerning air quality will lead to the closure of coal plants, increasing demand for gas and therefore upward pressure on gas prices. However, the increase in demand will be constrained by legislation concerning the rising share of renewables in energy consumption. Moreover, the security of supply will have an upward pressure on gas prices as users, in the knowledge that some suppliers may not be wholly reliable, agree to pay a higher price to be certain of delivery: especially when some suppliers turn out to be unreliable.

Chart 5.5 Long term outlook EU
(Forecasts)



Source: World Bank, IEA

However, an increase in gas prices will be restricted by the growing diversity of suppliers. This should lead to more competition and more competitive gas prices. Competitive pricing may also result from the expected increase in spot trading: something that is bound to happen, although we do not expect long-term contracts to be totally banned from the European gas market.

It is expected that contracts will become more flexible, in the sense that part of the contract will be on fixed terms and the rest will be destined for the spot markets. In the medium to longer term, gas prices are likely to increase only gradually in Europe, to a level slightly below USD 13 per MBtu.

Return to contents page

Part 6 – Outlook Global Gas Prices

In Part 2.3 we outlined a picture of global gas prices since the early years of the millennium. Two trends were noticeable. Firstly, the co-movement of the gas prices with the oil price is weakening. Secondly, differences in the weakening of gas prices in the US, Asia and Europe. While prices in Asia and Europe show a weakened correlation with the oil price, the US Henry Hub price started to drift downwards on the back of the shale gas boom. As a result, the US price diverged from the oil price as well as from the Asian and European prices. With this picture in mind, the question that we will attempt to answer in this final section is whether these trends will last over the forthcoming period. As in previous parts of the report, we make a distinction between the medium (until 2018) and long term (until 2035). In that respect, we follow the IEA, whose price projections are presented and discussed.

6.1 Price Outlook until 2018

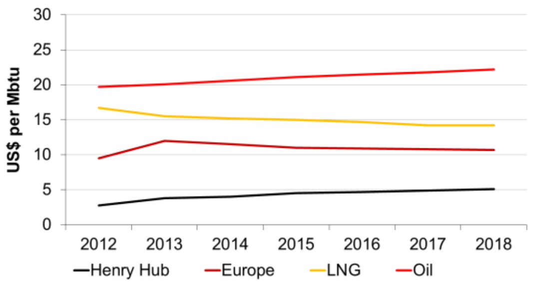
We have argued in our review of the US that the low prices of USD 2 - 2.8 per MBtu that were seen in 2012 would not be sustainable. They were the result of unusual circumstances, such as a very mild winter and still muted economic growth. Indeed, as these circumstances fall away, and new regulation comes into force to back up renewable energy consumption of gas will grow and prices will recover to around USD 4.6 per MBtu in 2018.[17] Gas production, especially shale gas, is expected to continue to thrive as production capacity is largely untouched despite the relatively low prices. Infrastructure bottlenecks are being addressed by pipeline investments and (re)building LNG facilities.

Those LNG facilities can be used for exports, primarily to the Asian market, where prices are around USD 16.5 per MBtu. This level is high because a number of large countries, including China and Japan, are gas importers and are willing to pay relatively high, oil indexed, prices under long-term fixed contracts that provide security of supply. But these high prices appear not to be sustainable either and we expect a decline to USD 14 per MBtu in 2018. The underlying forces are the production surge coming from the 12 new LNG facilities in Australia and East Africa and, indeed, the gradual growth of US exports made attractive by their price advantage of USD 10-12 per MBtu. This difference provides ample compensation for the USD 4.5 – 8.5 additional cost due to liquefaction, regasification and transport that come with LNG. The supply side dynamic that pushes up the number of gas providers also has an impact on the pricing mechanism: the share of long-term contracts based on oil price indexation is under pressure. And that, in turn, creates further downward pressure on Asian prices over the outlook period. The increased consumption that comes with economic expansion cannot prevent lower prices.

Meanwhile, developments in the European gas market are relatively muted. Neither shale gas production nor LNG imports are expected to play a large role. Production is slowly declining but demand is weak given the protracted economic recovery. Gradually more imports will be required, but this in itself is unlikely to affect prices. However, prices are expected to slide somewhat, to USD 10 - 11 per MBtu, as the number of oil price indexed long-term contracts continue to reduce as a result of weak demand and the LNG flux that will become available over the outlook period. Further pressure may come from US exports as the price difference of USD 5 - 6.5 per MBtu may still be attractive for LNG export to Europe at a costs of around USD 4.5 (the lower end of the range).

[17] To allow for proper comparison over time, all prices mentioned in this section are prices in real terms.

Chart 6.1 World Gas and Oil Price 2012-2018
(Forecasts)



Source: World Bank, IEA

The outlook until 2018 therefore demonstrates a noticeable change to the current picture drawn in Part 2.3. Firstly, the suggestion that co-movements of the gas price with the oil price will gradually disappear is confirmed. The roles of the US shale gas revolution and the considerable investment in LNG are dominant in this development. Secondly, the price divergence between the three major global gas markets will come to a halt and, even reverse as we see convergence towards a more global gas price. Again, the same factors - shale gas an LNG capacity expansion - come into play as driving forces. In addition, the mere weakening of the link of the gas price with the oil price supports this development: prices will become more market based, with ultimately only supply and demand (and not regional market characteristics) driving global price differences.

While this is the most accurate future picture that we can draw, it is by no means inevitable, simply because we have had to make a number of assumptions about underlying trends. For instance, while LNG capacity expansion should indeed materialise, if there are 'hiccups' in that process - for example due to cost overruns as skilled labour becomes more expensive in Australia and/or political risks materialise in East Africa - that capacity expansion may come under pressure. Price pressure in Asia and, to a lesser extent, Europe could then become indistinguishable in actual prices. There is also the possibility that US exports will not expand enough to provide support for the LNG capacity based price pressure in Asia. Indeed, so far the US government has been fairly reluctant to issue export licenses for gas. And finally, the change to more market based - and therefore lower - prices is not straightforward. There is strong resistance to market based pricing in the market from leading suppliers such as Gasprom and Sonatrach. Moreover, LNG projects are 80% oil price based to lower risk and capital costs.

6.2. Price outlook until 2035

The picture that we have drawn for the period up to 2018 is one of the convergence of gas prices. Under the set of assumptions that we have discussed above, the gas price in the US will be USD 5 per MBtu, while in Europe and Asia levels of USD 10-11 and USD 14 can be expected. The question now is whether this convergence level is sustainable in the long run: that is to say until 2035. We believe that it is, and that not much further convergence can be expected provided that two conditions are fulfilled during the outlook period. These are, firstly, that US exports will only gradually come on stream (to a level of 100 bcm) and, secondly, LNG costs remain broadly unchanged. We will now discuss the trends in the regions under these assumptions.

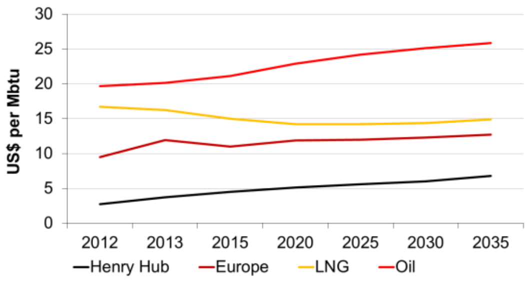
In Asia the steep increase in demand is on-going, particularly from China and India, and this is putting upward pressure on the gas price: pressure that will be largely countered by supply side developments. Indeed, US exports and further provision of LNG from suppliers in the rest of the world will contribute. Perhaps more critically, Chinese production, including shale gas, is expected to take off. These developments should be sufficient to largely check the underlying price pressure from 2020 onwards. As a result, there will be only a marginal and very gradual rise, to USD15 per MBtu, by the end of the outlook period. Under this scenario, the dominant fixed oil price based pricing will further erode over the outlook period, but slowly. Downward price pressure from that (institutional) source will therefore be limited.

In Europe there will also be underlying upward pressure on the gas price from 2018 onwards, as expectations are that demand will increase while supply declines. Increased demand will come from various sources. Anaemic economic growth will not last forever, and peripheral Eurozone countries in particular can be expected to grow as the impact of the crisis fades. Environmental concerns are unlikely to allow the current non-functioning ETS system to persist over the outlook period. That suggests that, with the price of carbon emissions finally going up, there will be a demand surge for alternative sources such as gas and renewables. European air quality legislation will lead to the closure of coal plants, and, again, a search for gas as an alternative. Supply will decline in countries like the Netherlands, while technical and environmental issues will prevent the development of significant shale gas production in Europe. The result of these forces will be that the gas price in Europe is expected to reach a level of around USD12 per MBtu during the outlook period. The movement away from fixed oil price based pricing will continue, but will lose force and reach its limit. As a consequence, price pressure will be constrained.

Ample shale gas reserves in the US indicate that its shale gas boom will last. This will be supported by environmental concerns about the use of coal for new thermal power generation and the expectation that the transport sector will start to contribute more substantially by switching from petrol to electricity. The price level of USD 4.5 – USD 5 per MBtu that we see developing up to 2018 further underpins this expected production increase: an increase that will make the US self-sufficient and therefore create the need to be able to export any production surplus. In our baseline scenario we assume that such export will be allowed, because the US government is, in the end, expected to give in to pressure from the energy sector. That will bring the aforementioned export level of 100 bcm on stream. It also allows the gas price to climb to a level of USD 6.5 per MBtu in the US.

The upshot of this is that prices in all regions will climb from 2018 onwards: in the US, to US 6.5, and in Asia and Europe to USD 15 and USD 12 respectively by the end of the outlook period. Therefore, global gas prices will rise from 2018. At the same time, further gas price convergence between regions is hardly discernible under the baseline scenario.

Chart 6.2 World Gas and Oil Price 2012-2035
(Forecasts)



Source: World Bank, IEA

However, there does seem to be room for price convergence: the price difference of USD 8.5 between Asia and the US market is at the upper end of the cost difference of USD 5.5 – USD 8.5 per MBtu. The price difference between Europe and the US is USD 5.5, while the cost difference is USD 4.5. It simply seems that more US production will create movement towards more convergence. As said though, US production hinges on the export opportunities that the US government allows the energy sector to take. In the baseline scenario it is constrained to 50 bcm. If exports are allowed to grow to levels significantly above this - to 100 bcm - and if liquefying, transport and regasification costs of LNG are contained, another scenario will present itself. This is what the IEA calls the price convergence scenario.

Under such circumstances, prices in Asia may be USD 2 lower and end up at USD 13 per MBtu. This process will be helped by the implied acceleration of the erosion of the oil indexed fixed prices: US deliveries at market prices will trigger arrangements for setting up more trading hubs. Similarly, the additional supply on the market will help reduce prices in Europe somewhat compared to the baseline scenario, to USD 11.5 per MBtu. US prices will be lower as well, albeit marginally, at USD 7 per MBtu. The overall picture that appears is then one of more price convergence, supported by an LNG cost increase containment. Otherwise, clearly the price differences will no longer be sufficient to warrant the expansion of LNG. Indeed, it is precisely that expansion that is needed to achieve price convergence between the world's regional markets.

Return to contents page

Literature overview

British Petroleum (2013), Statistical Review of World Energy.

Clingendeal International Energy Program (2013), Presentation training gas markets.

Deloitte (2013), Oil and Gas Reality Check 2013 A look at the top issues facing the oil and gas sector.

Deloitte (2013), Exporting the American Renaissance.

Economist (2012), Special report: Natural gas.

Ernst & Young (2012) Global LNG: Will new demand and new supply mean new pricing?

Eurogas (2013), Statistical report 2013.

Melling, A.J.(2010), Natural Gas Pricing and its Future: Europe as the Battle Ground, Carnegie Endowment, Washington, D.C..

International Energy Agency (2012), Medium Term Gas Report 2012, OECD/IEA, Paris

International Energy Agency (2013), Medium Term Gas Report 2013, OECD/IEA, Paris.

International Energy Agency (2012), World Energy Outlook 2012, OECD/IEA, Paris.

International Energy Agency (2013), Developing A Natural Gas Trading Hub in Asia, OECD/IEA, Paris

US Energy Information Administration (2013), Annual Energy Outlook 2013

The Global Market for Liquefied Natural Gas, Reserve Bank of Australia, Bulletin September Quarter 2011

David Jacobs

Return to contents page

Crédito y Caución
Paseo de la Castellana, 4
28046 Madrid
Spain

www.creditoycaucion.es