DIVERGING GAS PRICE INFLUENCES – IS A GLOBAL GAS PRICE POSSIBLE?

Chris Holmes [1]

1. IHS Purvin & Gertz

Keywords: 1. Gas Demand; 2. LNG Demand; 3. Gas Supply; 4. LNG Supply; 5. Shale Gas; 6. Gas Price; 7. LNG Price

1 Background

The global gas industry has experienced unprecedented change at the macro level over the last 2-3 years. Over this period an increase in global gas supply, as a result of the development of shale gas resources in North America and an unprecedented expansion in global liquefied natural gas (LNG) supply, came to the market at a time of weak global demand caused by the global economic crisis although demand has since started to recover. This environment has caused both a convergence and divergence of regional spot gas/LNG prices and a shift in the attitude of both gas/LNG sellers and buyers with regard to pricing terms for supply.

Although the commercial terms under which gas and LNG are traded have become more flexible in some parts of the world, a true global consensus on the value and price of gas has yet to emerge. Gas prices in North America are determined as a result of gas-gas competition while LNG buyers in Asia appear to be content with oil indexed LNG supply to meet the bulk of their import needs and prices in Europe exist somewhere between these two extremes. Based on analysis of recent historical gas/LNG trade data it is clearly evident that regional pricing differences have become increasingly influential in the direction of flexible LNG trade flows, pipeline gas import levels into Europe and off-take of LNG supplied under dedicated long-term contracts.

The development of gas and LNG prices in regional markets faces considerable uncertainty over the near to medium term and prices in each region will be subject to different influences and factors. In North America the economics of shale gas development will be a key determinant of regional gas prices while in Asia oil indexation will continue to be influential in the cost of LNG imports under medium and long-term supply agreements. The region with greatest uncertainty with respect to gas pricing is Europe where the longevity of oil indexed pipeline gas supply under medium and long-term agreements continues to be threatened by the increasing influence of prices at Europe's main gas trading hubs. Finally, the price of spot or flexible LNG supply will be determined by a number of factors including global LNG supply and demand fundamentals, regional gas supply and demand fundamentals, global and the price of gas in regional markets.

2 Aims

This paper is subdivided into two main sections: the first section examines the various factors that have influenced regional LNG and gas prices over the last few years while the second section examines the factors that are expected to be influential in gas and LNG price formation over the medium term and assesses the prospects for creation of a global gas price.

The historical review of gas and LNG prices examines the drivers of gas price formation since 2008 in each of the world's three main regional gas markets, these being

North America, Europe and Northeast Asia. For North America, the paper examines the increasing influence of shale gas production on prices and the linkages between gas production, drilling activity, gas demand, and inventory levels. For Europe, the paper examines the historical gas trade dynamics that includes displacement of pipeline gas imports by LNG imports, the response by pipeline gas exporters to loss of market share and the increasing influence of traded gas hubs on pipeline gas prices. For Northeast Asia, the paper examines recent changes in the price of LNG supplied under medium and long-term dedicated supply agreements. Finally, this section of the paper examines the factors that have influenced the price of spot and flexible LNG supply and the impact of regional price variations on flexible LNG trade flows around the world.

The second section of this paper examines the factors that are expected to influence regional gas and LNG prices over the medium term. As such the sustainability of the aforementioned factors affecting regional gas and LNG prices are discussed and any new influences are identified. This section of the paper also presents a short-term outlook for regional gas supply and demand and the impact of regional gas market fundamentals on global LNG trade patterns. The paper concludes with an outlook for gas and LNG prices around the world and assesses the possibility for the emergence of a global natural gas price.

3 Discussion

a. Historical review of gas price influences in North America

Natural gas pricing in North America is complex and determined primarily by gas-gas competition, being influenced by many factors including supply/demand pressures, seasonal/regional weather patterns, inventory fluctuations, the cost of gas supply and market perception. Since liberalisation of the U.S. gas market in the mid 1980s, natural gas prices have rarely been closely linked to the price of alternative fuels (primarily distillate and residual fuel) with the result that producer competition has been the primary determinant of absolute pricing levels for much of the last 20-30 years. This has meant that, during times of abundant supply, prices have tended to be much lower than the reference prices set by alternative fuels with the primary determinant being the cost of supply.

The U.S. natural gas market has undergone many profound changes since 1990 as the market tightened gradually through the decade with the result that gas was more frequently in competition with alternate fuels (distillate and residual fuel oil) for large industrial and electric power companies that had fuel-switching capability. The ability to switch fuels, or simply the threat of fuel switching, played an important role in moderating gas prices in the second half of the 1990s. While gas markets had tightened somewhat relative to the early 1990s, there was still sufficient gas to meet all potential gas demand.

During the late 1990s, two important trends developed that resulted in a significant shift in market fundamentals and pricing. The first phenomena was a significant expansion of U.S. electric power generation capacity and an over-reliance on gas as the source of incremental power fuel as much of the new electric power plants built in the late 1990s and early part of this century were based on natural gas. The second important development was the deterioration in conventional gas exploration and production activity. Throughout much of the 1990s, companies were able to maintain and increase their productive capacity in the Lower 48. This helped gas prices remain reasonably low during most of the decade and facilitated growth in all consuming sectors of the gas market. Technological innovations and efficiency gains also helped keep drilling and production costs low. At the turn of the century, exploration drilling failed to result in sufficient gas reserves additions and even though the rig count was relatively high in the early part of the century, productive capacity actually declined. The consequent upward pressure on price caused by these two factors resulted in gas prices for much of the period between 2004 and 2008 to trade in excess of $6/MMBtu and peak at more than $12/MMBtu in late 2005 and, again, in the middle of 2008 although this latter peak was supported somewhat by record international oil prices of nearly $150/bbl.

A tightening of gas supply/demand dynamics in North America in the ten years leading up to the middle of the last decade had two significant, yet polarised, consequences. The expectation of declining indigenous North American gas production prompted widespread investment in LNG import and regasification capacity with some commentators predicting that the U.S. would be come the world's largest importer of LNG within 20 years. Of greater significance was the fact that higher domestic gas prices supported ongoing development of technology for the exploitation of domestic unconventional gas resources, primarily from shale gas.

As noted above, high gas price expectations spurred investment in unconventional sources of natural gas which together with rapid technological advances in horizontal drilling and hydraulic fracturing, partly as a result of these investments, expanded the economically recoverable portion of the shale gas resource that, hitherto, had been only technically recoverable. The net effect has been a significant increase in the recoverable gas resource base of North America with technically recoverable resources estimated in 2010 to be 85% higher in 2010 than ten years earlier and more recent resource estimates suggesting an even greater increase. The increase in resources is such that the region is now expected to become self-sufficient for the foreseeable future and increasingly likely to become an exporter of LNG in the near term. It is this largely unanticipated and rapid increase in shale gas production that has brought significant additional supply sources to the market and changed the natural gas landscape in North America for the foreseeable future.

The increase in gas production caused by the shale gas revolution coincided with the exceptionally deep economic recession that took hold in 2008 and prevailed through much of 2009 resulting in a collapsing of gas prices from the high levels reached in mid 2008. The economic downturn caused a decrease in demand for natural gas in 2009 but demand has since recovered, being supported by abundant supply and low prices. Gas demand grew by 7.3% in 2010 and an estimated 4.0% in 2011 with power generation demand, a significant beneficiary of low gas prices which has meant that the fuel has been competitive with coal and displaced coal for power generation, increasing by 4.1% and 0.4%, respectively.

While low gas prices in 2009 caused a decline in drilling rig activity (from a peak of nearly 1,600 rigs in late 2008 to around 700 rigs in the middle of 2009) and consequent decline in production, this was short-lived. A combination of: the requirement to drill for shale gas to retain acreage production rights; continued reductions in drilling costs and improvements in well productivity; and migration of drilling activity towards shale resources with higher natural gas liquids content have all served to increase drilling rig activity (that has stabilised at 900-1,000 active rigs) with the result that gas production has been on an increasing trend since the beginning of 2010. An interesting observation in the relationship between gas price and drilling rig activity is that rig activity appears to have become more responsive to changes in prevailing gas price over the last few years. In the period to the beginning of 2006 changes in drilling rig activity appeared to lag changes in gas price by about six months. There then followed a 2-3 year period during which rig activity and gas price became disconnected. During this time supply was constrained and the prevailing price trended towards that of competing liquid fuels at a level that was above the cost of marginal production. It was during the latter part of this period that production from shale gas resources became increasingly influential in total domestic production with the result that, following the collapse in gas prices in the second half of 2008, rig activity and gas price reconnected. However, since this time rig activity has appeared to be more responsive to changes in gas price with the time lag reduced to three months.

Shale gas production, therefore, has become increasingly significant in domestic U.S. natural gas supply as production has risen from less than 3 billion standard cubic feet per day (Bscfd) at the beginning of 2007 to 18 Bscfd in late 2011, during which time total U.S. production has risen from around 50 Bscfd to nearly 63 Bscfd in the third quarter of 2011. This represents an increase in contribution to total indigenous production from around 6% to nearly 30% and presents clear evidence that the development of shale gas resources has not only arrested the decline in domestic gas production but is the prime driver behind the reversal in the trend.

A consequence of the changing gas supply/dynamic in North America is the changing impact that inventory movements have had on Henry Hub prices. Reporting of weekly inventories in the U.S. has long been an indicator as to whether the market is over or under-supplied and changes in weekly inventory levels have typically resulted in changes in underlying gas price, being dependent on whether movements in a particular time period are in line, above or below typical movements for that time of year. This is phenomenon is changing. Prior to the advent of shale gas higher-than-expected withdrawals from inventory would often result in near exponential price appreciation while higher-than-expected injection into storage would contribute to some price weakening but not to the same extent that a comparable change in withdrawals had. With the apparent availability of abundant shale gas supply working inventories in recent years have tended to be at the higher end of the historical inventory range with the result that prices have become less responsive to changes in inventory when compared to historical changes for the same time period to such an extent that the price/inventory change curve has been almost flat i.e. prices have not moved when changes in inventory have been different to historical movements.

It is now clearly evident that the North American gas industry is entering an era of abundant supply during which time prices will be determined primarily by the cost of supply rather than by the value of gas when compared to the price of an alternative fuel. Thus, it is appropriate to consider the cost of production in North America when evaluating the region's role in a global gas market and its contribution to the formation of a global gas price. In the early days of the shale gas era, production costs were generally estimated to be in the region of $5.0-7.0/MMBtu. Ongoing development of the technology required to develop shale gas resources and migration to the wetter gas plays has reduced the estimated cost of production cost for dry gas to around $5.5/MMBtu while that for wet gas is significantly lower at $2.5-3.0/MMBtu although it should be noted that the location of production is a significant factor in the evaluation of any shale gas resource in terms of price that can be realised. Furthermore, the production cost curve appears to be elongated to such an extent that the expectation exists for a sustained period of relatively low gas prices in North America.

b. Historical review of gas price influences in Europe

Since the beginning of the natural gas industry in Europe, importers and exporters have based gas trade on long-term contracts with duration of the order of 20–25 years. The price of gas under these contracts has been widely based on the principle that the price of gas should generally be competitive with the prices of alternative (non-gaseous) fuels – known as the "market value principle". The market value principle developed after the oil price increases of 1973–74 when the relative value of fuels competing with gas in the energy market became subject to major fluctuations. Initially, the market value principle was used in negotiations between the Dutch state gas company, Gasunie, and its customers in the early 1980s and has been the basis of Continental European gas pricing for supply under long term contracts to the current day.

Two main alternatives to the market value principle have been used in Europe. The first was parity with crude oil export prices but this became a major issue in the late 1970s and early 1980s, particularly in the Algerian LNG contracts with France and Belgium. This method of pricing led to gas becoming more expensive than the fuels against which it was competing in end-use markets with the result that gas lost market share. This was a major factor in the buyers' preference for the market value principle. The second alternative was "Cost-Plus" pricing that was used in the U.K. by the state-owned British Gas Corporation in its purchases of gas from North Sea producers. Because all gas produced on the U.K. Continental Shelf was, by law, required to be offered to British Gas, the company was able to determine the cost of production and transportation of gas to the beach, and to offer sellers that price plus a profit margin.

The rationale for oil-linked gas pricing was that natural gas and oil are substitutable in both the short and the longer term. Price formulae were designed to ensure that the customer base continued to burn gas rather than returning to oil products since the majority of customers had switched from oil products to gas and, given a price incentive, retained the ability to switch back. If customers switched back to oil in large numbers, this would not only deprive gas importers of their market, but force them to incur take-or-pay penalties in their long term contracts with exporters. Until the mid 1990s almost all the gas supplied into the European market included some form of indexation, mainly to refined oil products although other indices have also been used.

With progressive liberalisation of European gas markets over the last 20 years, traded gas exchanges have started to emerge and the price of contracted gas supply is becoming increasingly referenced against prices on these exchanges. However, there has not been a uniform movement towards exchange-based pricing.

There was wide variation in the pricing of gas throughout Europe in the middle of the last decade although oil indexation dominated with two refined oil products (light fuel/gasoil and heavy fuel oil) used as references for nearly 75% of gas sold in the EU wholesale market. At this time gas accounted for nearly 10% of the index with the rest being a range of other energy products, inflation and non-energy elements as shown in the table below.

GAS PRICE INDEXATION BY CONSUMING REGION - 2004 (1)

Index	U.K.	Western Europe (2)	Eastern Europe (3)	European Union	Total Europe (4)
Heavy Fuel Oil	14.6%	30.0%	48.1%	29.5%	28.2%
Light Fuel Oil / Gasoil	16.2%	50.1%	47.2%	44.8%	41.9%
Traded Gas Price	40.0%	4.9%	0.0%	9.8%	12.6%
Electricity Price	7.0%	0.6%	0.0%	1.5%	2.0%
Coal Price	1.1%	2.6%	2.1%	2.3%	2.2%
Other	1.1%	0.0%	0.7%	0.0%	0.3%
Fixed Price	2.9%	5.2%	0.8%	4.4%	4.2%
General Inflation	16.5%	2.0%	1.1%	4.1%	5.3%
Crude Oil	0.6%	4.6%	0.0%	3.6%	3.2%
Demand, Bcm (5)	97.4	276.3	42.4	485.0	416.1

Notes: 1) Source : Preliminary Report, Presentation of DG Comp's Findings, Competition Directorate-General, 16 February 2006

2) Western Europe consists of Austria, Belgium, Denmark, France, Germany, Italy and the Netherlands

3) Eastern Europe consists of Czech Republic, Hungary, Poland, Slovakia and Slovenia

4) Weighted average of U.K., Western and Eastern European countries

5) Source : BP Statistical Review of World Energy 2009

At this time, the U.K. market, widely viewed as being the most liberalised in Europe, had 40% of its has supply priced against the NBP hub with most of the remaining supply as legacy contracts priced against oil products and inflation. Other indices accounted for less than 13% of price formation. Exchange prices had only a small influence (less than 5%) on the price of gas supply into Western Europe with the major determinant of price being either refined oil products or crude oil. In Eastern Europe where supply from Russia was dominant, gas was priced almost exclusively against refined oil products.

From a producer or supplier perspective, long term contracts with suppliers from the Netherlands, Norway and Russia had extremely similar pricing mechanisms with 35-40% indexation to heavy fuel oil and 50-55% indexation to light fuel oil/gasoil. For these three exporters, these two refined products comprise around 90% of indexation. There was a significant contrast between these three exporters and Algerian contracts, U.K. and other EU supply. Algerian contracts had high linkage to oil (95%), with crude oil the dominant indexation element. Typically Algerian LNG contracts were indexed against crude oil only whereas sales of pipeline gas have been indexed against refined oil products and crude oil as shown in the table below.

GAS PRICE INDEXATION BY PRODUCING REGION - 2004 [(1)]

Index	U.K.	Netherlands	Norway	Other EU	Algeria	Russia
Heavy Fuel Oil	9.2%	36.5%	35.2%	38.9%	5.6%	39.0%
Light Fuel Oil / Gasoil	11.0%	55.5%	52.1%	29.3%	19.3%	53.0%
Traded Gas Price	37.0%	1.8%	4.0%	30.2%	0.0%	0.3%
Electricity Price	9.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Coal Price	1.2%	0.9%	3.1%	0.6%	0.0%	3.1%
Other	0.2%	0.0%	0.6%	0.0%	0.0%	0.0%
Fixed Price	3.3%	4.4%	2.3%	0.0%	5.6%	4.4%
General Inflation	28.1%	0.0%	2.7%	0.0%	0.0%	0.2%
Crude Oil	0.8%	0.9%	0.0%	1.0%	69.5%	0.0%
Net Production/ Exports, Bcm [(2)]	96.4/10.4	68.5/53.6	78.5/76.3	62.5/0.0	82.0/56.9	573.3/200.4

Notes: 1) Source : Preliminary Report, Presentation of DG Comp's Findings, Competition Directorate-General, 16 February 2006

2) Source : BP Statistical Review of World Energy 2009 & IEA Natural Gas Information 2009

More recently it has become evident that the price of gas at traded hubs has become increasing influential in gas formation in the European market at the expense of oil price and other indices. As noted above the price of an increasing amount of gas supplied into the U.K. market is referenced against traded prices at the NBP hub. It has been reported that in 2007/2008 there were only a few legacy contracts remaining in the U.K., estimated at around 15% of total supply, which would have had some form of indexation to oil and other indices. However, in Eastern Europe, where imports of gas dominate as a percentage of total supply and the Former Soviet Union (FSU), mainly Russia, is the dominant source of imports (in 2007 the FSU accounted for nearly 93% of total imports and nearly 75% of total supply) a change in pricing policy is not understood to have taken place in the last few years. In other words oil price indexation remains the main determinant of price.

Although the vast majority of gas supplied into Western Europe remains indexed to oil, indexation to traded hub prices does appear to have increased in recent years. In part this has been due to an increase in the amount of spot or flexible LNG supplied into the European market over this period, much of which has been priced against a gas index such as the NBP price. Increasing pipeline connectivity between the U.K. and Continental

European markets and increased LNG supply flexibility have enabled gas traders to use the U.K. as a gateway to the European market and this opportunity has clearly been exploited in recent years. Although the U.K. has become increasingly dependent on imported supply since 2004, exports of gas to Continental Europe have actually increased over this time as imports of LNG plus pipeline gas from Norway and the Netherlands have effectively been re-exported to the European market. During this time the U.K. has provided a deep, liquid market into which gas could be sold with gas resold into the oil-indexed market of Continental Europe.

Much of the world's surplus gas supply in recent years has found its way into the European market in the form of LNG at prices that have been at significantly lower levels than that of oil-indexed pipeline gas. Over the period 2006 to 2011, Europe's net import requirement has increased from 254 billion cubic meters (Bcm) to an estimated 266 Bcm. During this time imports of LNG have increased from 42 million tonnes (47 Bcm) to 71 million tonnes (99 Bcm) while imports of pipeline gas have declined. Of the LNG imported into Europe over this time, the share of flexible LNG supply increased from around one-third of supply to 50% of supply. Thus, it is clearly evident that pipeline gas has lost market share to flexible LNG supply in recent years. After much pressure from their buyers, exporters of pipeline gas to Europe agreed in late 2008 and early 2009 to introduce an element of gas price indexation into their long-term contracts, albeit on a temporary basis and official statistics clearly show divergence between the traditional oil-indexed gas price and that actually reported for deliveries into Europe. While exact details of the degree to which gas indexation has been introduced into pipeline contracts varies between exporter, in general terms it appears to be that take-or-pay volumes have retained oil indexation while the price of incremental off-take beyond this level have been linked to hub prices.

c. Historical review of gas price influences in Northeast Asia

The initial long-term contracts for LNG sold to Japan from Alaska and Brunei in the late 1960s and early 1970s were concluded at a fixed price of around \$0.50/MMBtu on a delivered basis. The first "oil price shock" in 1973-74 caused oil prices to escalate sharply and LNG suppliers renegotiated their pricing terms with the Japanese with the introduction of a linkage to crude oil prices with the degree of oil linkage varying between the various contracts in force at the time. In the early 1980s, to support the expansion projects at the Arun and Bontang plants, the Indonesians signed a second round of sales contracts with Japanese buyers that increased the price linkage to crude oil from the previous 90% to 100%. Similar contract terms were used for sales to Korea and by the Malaysians for their initial contracts with Japanese buyers.

The formula used in most of the Asian LNG contracts that were developed in the late 1970s and early 1980s was of, or could be reduced to, the following general form:

$$P_{LNG} = \alpha \times P_{crude} + \beta$$

where, P_{LNG} = FOB or CIF price of LNG in \$/MMBtu;

P_{crude} = Price of crude oil in \$/Bbl;

α = Crude linkage slope; and

β = Constant in \$/MMBtu.

The value for α, or slope, dictated the degree of linkage between LNG and crude oil prices with the slope typically in the range 0.1485-0.1525, thereby representing a linkage of 85-90% to crude oil. Historically, there was little negotiation between parties over the slope for most of the LNG contracts agreed during this period, with most negotiating effort focused on the value of β, i.e. the constant. Typically, for LNG sold on a delivered ex-ship basis (DES), the value for β lay in the range $0.70-0.90/MMBtu, although would be lower for FOB sales.

With the exception of Indonesian LNG sales, all contracts that contained the above formula used what is known as the Japan Customs Cleared price for crude oil, otherwise known as the Japanese Crude Cocktail (JCC), in the formula. The JCC price represents the average price of crude oil imported into Japan, as reported by the Japanese Ministry of Finance. The actual JCC price input into the formula typically incorporates a three-month lag from the date of lifting or delivery, i.e. delivery in June would be based on the March JCC price. The crude oil price reference for Indonesian LNG contracts was based on the Indonesian Contract Price or ICP instead of JCC.

The price linkage to crude oil essentially remained unchanged from 1973-74 until the oil price crash of 1986 that was prompted by OPEC's decision to abandon the use of Official Government Selling Prices for crude oil. The severe weakening of oil prices had a significant impact on LNG project revenues and, again, suppliers sought co-operation from the Japanese buyers. The Japanese were receptive to these requests with the result that the so-called "S-curve" was introduced into the price formula. The introduction of the "S-curve" into Asian LNG pricing formulae in the mid 1980s served to reduce fluctuations in LNG prices by providing a bigger premium over oil for the seller at low oil prices but conversely capped the LNG price at higher oil prices. Most LNG contracts that incorporated the "S-curve" also had floor and ceiling oil prices that determined the Applicable Range over which the contract formula could be applied or set the minimum or maximum oil prices that could be used in the pricing formula.

In relative terms, LNG term contract prices evolved slowly over the 1970s, 1980s and 1990s with buyers and sellers reacting to external factors in an orderly way thereby reflecting the conservative nature of the business. The status quo changed dramatically in the late 1990s and in the early part of the last decade as new buyers entered the market at a time when LNG production capacity remained unsold with price terms that were radically different to those that had occurred previously.

In 2002 RasGas managed to reach agreement with India to supply LNG on an FOB basis from the RasGas 2 project for a 25-year period from 2004. For the period to 2008 the contract price was fixed at $2.53/MMBtu but thereafter the contract price was linked to JCC. However, in a significant departure from traditional contract price terms the contract did not include a β constant in the formula. The most radical departure from traditional Asian pricing terms involved the supply of LNG to China. Sensing a buyer's market, and in an attempt to get the lowest possible price, China launched a tender for LNG supply to Guangdong that was won by Australia. The structure of the Guangdong contract's pricing terms is similar to traditional oil indexed LNG contracts although the degree of indexation is far lower (α slope), the β constant higher. It has been reported that the α slope has a value of 0.0525 resulting in only 30% indexation to crude oil. A second similar deal was concluded into Fujian with supply from the Tangguh project. As a further indication of the surplus supply that existed in the market at the time, Korea departed from its traditional pricing terms and managed to secure a deal with Tangguh that had similar characteristics to the Chinese deals.

The Tangguh contract with Sempra signed in 2004 and based on the Southern California (SoCal) border gas price, was the first time an Asian LNG producer had sold LNG on a term basis on anything other than a linkage to JCC since the early days of the LNG industry when the initial Alaska and Brunei contracts were priced on a cost-plus basis. A willingness to depart from traditional Asian pricing terms was accepted by others with Qatari sales into the Atlantic Basin priced against Henry Hub in the U.S., the National Balancing Point (NBP) in the U.K. and Zeebrugge Hub in Belgium. All of these markets trade at prices that are more reflective of gas-to-gas competition than in Asia. In another departure from traditional Asian contract pricing terms, some contracted supply into India and BG's contract to supply Singapore are reported to include indexation against Brent crude oil.

Despite weak LNG market fundamentals in the last 2-3 years, contract prices in the Asia-Pacific region have managed to remain relatively strong. Much of the production capacity that has come on-stream in the last couple of years was contracted before construction commenced although a significant portion of it, particularly from Qatar, was destined for the Atlantic Basin market and sold under FOB contracts to the equity partners in each project with supply having destination flexibility. However, Qatar Petroleum retains a high degree of control over the marketing of these volumes and, whenever possible, has converted tranches of supply into dedicated oil-indexed contracts with Asian buyers. In doing so, Qatar Petroleum has remained of the view that the relatively weak prices of the last couple of years are a short term phenomenon, and buyers should look to secure long-term deliveries in order to guarantee supply once the current supply surplus has been drawn down.

Pricing terms for long-term LNG supply to Asian buyers peaked in 2008 with deals reported to be done with a slope to the JCC index of around 15%. It is understood that an agreement for Qatari supply to China was concluded at near parity with crude which would imply a slope of 17.25%. However, with weak market fundamentals in the last couple of years, term prices appear to have weakened as evidenced by the agreements signed for LNG supply from Papua New Guinea to China, reported with a slope as low as 13.5-14.0%, although other reports indicate that deals were concluded at a slope of 14.85%. However, even at a slope of less than 15%, the deals reported to have been concluded by ExxonMobil attracted a negative reaction from Qatar. As ExxonMobil is a shareholder in projects in both locations, the Qataris felt that the Papua New Guinea deals undermined its own marketing efforts as they had been trying to achieve prices as close to parity with oil as possible. Thus, currently the market for term LNG supply appears to be settling at slopes at or above those used historically, i.e. 14.85%.

d. Historical review of the price of flexible LNG supply

The price of flexible LNG supply or the so called "spot" price is a fairly recent phenomenon that has come to the fore only in the last five years or so as LNG off-takers have expressed a willingness to take increasing market and price risk for supply from new projects that came to market in the latter part of the last decade. As such, from a position of virtually no flexible trade at the turn of the century it is estimated that 83 million tonnes of the 237.0 million tonnes of LNG delivered in 2011 (thereby representing 35% of all deliveries) was under flexible terms, i.e. supply that had no destination restrictions with the ability to be sold into the market of highest return.

A liquid short-term or spot market for gas has existed in North America for many years and is rapidly becoming established in Europe, mainly northern Europe. As described above these market hubs have been used increasingly for pricing of natural gas and LNG delivered into these locations. However, the structure of the gas market in Asia has meant that a similar market hub, against which the price of spot or short–term trades can be referenced, has yet to be established. However, in the latter part of the last decade a spot market has developed for LNG in Northeast Asia, known as the Japan-Korea Marker (JKM) price. Although trading volume in the market has expanded, the market is not particularly liquid and volatility is relatively low, especially when compared to the oil markets. LNG sold at the JKM price is priced on a DES Northeast Asia basis and has been influenced by several factors in the last few years.

The JKM market really came into prominence after a large nuclear power station operated by Tokyo Electric Power Company (TEPCO) had to be shutdown following a major earthquake in Japan in the middle of 2007. At the time the global LNG market was very tight and TEPCO (and other Northeast Asian buyers and utilities) had to pay very high prices for spot LNG supply to its gas-fired power stations to replace lost nuclear capacity. Failure to secure LNG supply would mean TEPCO having to increase its purchases of oil to burn in its oil-fired generation capacity. Thus, the price of oil delivered into Japan's power sector, after taking into account differences in thermal generating efficiency, set the upper limit for the price of spot LNG sold into the JKM market at the time. In the 12-month period to the middle of 2008, JKM prices were very strong and were disconnected to prices in the Atlantic Basin. As a result, flexible LNG supply flowed out of the Atlantic Basin market to meet Asian demand.

The combined effects of weak global demand for gas and LNG caused by the global economic crisis and an unprecedented amount of new gas liquefaction capacity coming on-stream created a global gas and LNG surplus during 2009 and into 2010. As oil prices declined in late 2008 and early 2009, spot LNG prices weakened with the result that LNG prices in Asia and hub prices in northern Europe and North America converged. In essence the market took the view that the U.S. would be the market of last resort as it had the storage capacity to absorb any LNG supply surplus that existed. At this time it could be viewed that a truly global market for LNG (and gas) had developed. However, the advent of shale gas in North America and with European traders demonstrating the ability to import LNG cargoes in preference to higher priced pipeline gas supply in late 2009 and beyond, a disconnect developed between NBP and Henry Hub prices. Thus, with northern Europe viewed as the default outlet for surplus LNG supply, spot prices in Northern Europe became the reference against which spot LNG was traded in both the Atlantic Basin and Asia-Pacific markets.

This situation again altered following the major earthquake in Japan that occurred in March 2011. As was the case with the earthquake that occurred four years earlier, TEPCO suffered a major loss in terms of its nuclear capacity although the effects were far more widespread on this occasion with much of the country's nuclear capacity shut down for safety reasons. The net impact was for the power generation companies to increase purchases of oil and flexible LNG supply with the result that the JKM LNG price appreciated through the remainder of the year relative to the NBP price and prices in the two markets diverged. Again, it appeared that the alternative fuel for Japan's power generation sector was oil and it was the price of this commodity that was providing upward support to regional spot LNG prices.

e. Expected medium term gas price influences

It is clear from the above that the gas market has experienced significant change in recent years at both the regional and global level. The questions are whether these changes are temporary or permanent and whether any other influences are expected to emerge over the short to medium term.

The North American market appears to have an abundance of low cost supply to such an extent that the regional landscape has changed beyond all expectation. While the cost of production is expected to be the dominant influence in North America, there are three other factors that are seen to have a possible influence on future price levels in the region, these being:

- The comparable value of gas in the power sector relative to coal;
- The development of potential LNG export projects; and
- Imposition of tighter regulations on shale gas operations.

The price of coal sets a floor for natural gas prices in the power generation sector and this has been evident for some months now in North America with the displacement of coal-fired generation by natural gas being one of the main drivers of recent gas demand growth.

With a coal-fired power generation capacity expected to retire over the medium, the main beneficiary will be gas and this structural change will support further growth in gas demand. Nevertheless, significant coal-fired power generation capacity will remain in the region and therefore will continue to provide a floor for gas prices over the medium term.

Not so long ago North America was widely expected to become a significant importer of LNG but the advent of the sale gas revolution has totally flipped this dynamic to such an extent that numerous LNG export projects are being developed and the region is now expected to become a significant exporter of LNG. At the time of writing three projects are targeting to commence LNG exports in 2015 with a total export capacity of 7.4 Bscfd (equivalent to nearly 55 million tonnes p.a.) with a further four projects less well-developed having a similar total export capacity. Only one of these projects (Cheniere Energy's Sabine Pass project with a capacity of 2.8 Bscfd or 20.7 million tonnes) has received Department of Energy approval for exports to both Free Trade Agreement (FTA) and non-FTA countries, but has yet to receive Federal Regulatory Energy Commission (FERC) approval. However, studies by the Energy Information Administration (EIA) that have reduced estimates of U.S. shale gas resources and concluded that exports would raise domestic gas and power prices have only served to ensure that the rate of development of LNG export projects will likely be less than straightforward. The counter view is that while estimates of recoverable resources contain considerable uncertainty, the production cost curve is sufficiently long such that gas prices are unlikely to be significantly affected unless export projects are developed at an uncontrolled rate. Nevertheless, although some export projects are targeting a 2015 start-up, this schedule is considered to be overly optimistic by a couple of years meaning that any impact on prices will occur in the longer term rather than in the short to medium term.

Probably the single greatest near term unknown relates to environmental concerns over such issues as ground water contamination as a result of the technology and practices used for the extraction of shale gas. To this extent, state and industry regulators have started to impose stricter regulations on shale gas operations that will undoubtedly result in higher production costs. It is probably too early to be able to assess the impact of tighter regulations on production costs but, based on what is known at the time of writing, it would appear that an increase in production cost of $0.5/MMBtu is likely with this cost increasing to $1.0/MMBtu under the tightest regulatory scenario. Thus, by including these higher production costs, the prospect for a prolonged period of low natural gas prices in North America remains.

In Europe the supply / demand dynamic is not expected alter materially over the short to medium term although there will be an increasing dependence on imported gas supply. Although indexation of long term gas prices to traded gas prices has increased at the expense of oil indexation in recent years, neither one of these mechanisms has been able to achieve dominance with the result that a hybrid market has developed. The question over future pricing influences in Europe really comes down to whether one of these two mechanisms can become the dominant influence in the market. While the European Union would favour increasing indexation to hub prices it has limited powers to enforce such mechanisms on extra-regional suppliers unless an extended period of excess global gas supply materialises in which case buyers will invite their suppliers to negotiating table in order to secure supply at competitive price levels. Unfortunately, the expectation is for a tightening of the global gas market to the year 2015 with LNG being pulled increasingly to the Asian market with the result that LNG imports into Europe are expected to decline, being replaced by increased imports of pipeline gas.

In a scenario of increasing pricing power, Europe's pipeline gas suppliers are expected to stand by their preferred pricing mechanisms i.e. oil indexed prices. However, traded gas hubs have developed to such an extent in recent years that they are unlikely to become redundant. This leads to the expectation that these two methods of price determination will continue to co-exist over the medium term with the relative mix of oil indexed and gas indexed pricing influences varying over time, being dependent on prevailing market conditions. In any event, with the expectation that the global LNG market will have absorbed the supply surplus that has existed in recent years over the near term, the market will again be tight with the result that traded hub prices will strengthen and move closer to the price of gas imported by pipeline under long term agreements, thereby reducing the influence of gas hub prices in the cost of supply under long term pipeline contract.

Recent agreements for the supply of LNG under long-term agreement in the Asia-Pacific region suggest that there continues to be a desire on the part of the sellers to retain indexation to crude oil and an acceptance by buyers to maintain the status quo. Furthermore, a combination of the geographic isolation of Asian markets, strong demand for LNG (and other energy forms) from China, and the high cost of developing new sources of LNG for a variety of reasons all present a challenge to new project developers. As each of these factors create momentum for higher prices, it would appear that future LNG selling prices and the degree of indexation to oil will have to remain high in order for new projects in high cost areas to progress to sanction. Thus, it is the expectation that oil indexation will remain in existing and be used in future LNG contracts in the region.

The future price of spot LNG in Europe and the Asia-Pacific region is expected to remain a function of the price of gas in the NBP market and the cost of oil for power generation in Northeast Asia. Global LNG market fundamentals are expected to tighten such that by 2013/2014 the global LNG market will have absorbed any supply surplus that exists and the market will again be tight with the result that NBP (and Continental European) prices will strengthen and move closer to the price of gas imported by pipeline under long term agreements. Additional spot LNG demand from Japan to cover the loss of nuclear and coal-fired power plant capacity from the earthquake/tsunami damage is expected to reduce the expected potential LNG supply surplus in the global market and provide a measure of support to European gas prices. Thus, it is expected that spot LNG prices in Asia will strengthen in the 2014/2015 period until the next wave of Australian (and possibly North American) LNG supply projects come onto the market. For a couple of years after this time some weakening in spot prices is expected as this new capacity is absorbed into the market.

4 Summary and Conclusions

The oil market has shown that a global price can be achieved if the hydrocarbon stream concerned can move freely between markets in order to exploit regional price differences and thereby realign those regional prices. In order for this to happen the quality of the hydrocarbon stream must be accepted in all markets, infrastructure must exist to transport the hydrocarbon between locations and a liquid market must exist in the regional market into which the hydrocarbon is sold. For many years the prerequisites did not exist in a global gas market that was dominated by captive pipeline supply infrastructure and an LNG industry that involved rigid point-to-point trade.

In recent years the introduction of increasing LNG supply flexibility, extensive investment in gas liquefaction, LNG transportation and LNG import and regasification infrastructure as well as the development of liquid gas markets in North America and, in varying degrees, in Europe plus a nascent spot market for LNG in Asia have all gone someway to creating the required enabling environment for a global gas market to develop. Market events for a short period in 2009 have shown that the concept of a global gas price is not wishful thinking and LNG has proved itself to be the mechanism through which such an objective can be achieved.

The advent of abundant shale gas supplies in North America has created a long-standing dislocation between that market and the global market with gas priced in the former on the basis of gas-gas competition, the primary influence being the cost of production or supply. For reasons of supply security Asia is expected to retain oil indexation for term LNG supply while spot LNG prices in Northeast Asia are expected to be influenced by both European hub prices and oil prices depending on the degree of tightness in the flexible LNG market. With gas-gas competition to the west and a high degree of oil-indexed gas prices to the east, gas prices in Europe are expected to remain a hybrid of the two mechanisms. These factors would suggest that a global gas price is unlikely to materialise over the near term and while this may be true there appears to be sufficient linkage between European and Asian markets to suggest that gas prices between the two markets will be connected on an intermittent basis rather than on an ongoing basis, the major determining factor being the degree of market tightness in the flexible LNG market.

In conclusion, while a true global gas price still appears to be some way off the degree of market connectivity is significantly greater than has been the case in the past. Flexible LNG supply has been the enabling factor in achieving this and the expectation is that the existence of flexible LNG supply in the future will enable varying degrees of future connectivity between Asian and European gas markets.