

**ARABIAN GULF LNG IN NORTH WEST EUROPE:
MANAGING RISKS**

5TH DOHA CONFERENCE ON NATURAL GAS: STRETCHING FRONTIERS

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Mr Frisch has provided consulting services to clients or projects in West, Central and Eastern Europe, Russia, the Middle East, North and West Africa, Japan, Australia and New Zealand. He is a chartered engineer in his home country of Norway and an economist (degrees from Newcastle upon Tyne, UK and Massachusetts Institute of Technology (MIT), USA). He is a member of the Society of Petroleum Engineers (SPE) (since 1975), the International Association of Energy Economics (IAEE) and the British Institute of Energy Economics (BIEE). He has published a number of major articles addressing strategic and commercial gas issues in the international energy press.

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Mr Lapuerta directs the London office of The Brattle Group, an international consultancy specialising in the economic and financial analysis of the energy industry. His practice focuses on the valuation of natural gas businesses, the analysis of competition in natural gas markets, and on the appropriate design of regulations for the liberalisation of the gas industry. He advises companies on the optimal strategies for purchases and sales of natural gas, considering future market developments and regulatory uncertainties. Much of the work involves business economics, performing rigorous numerical analyses of business questions such as the optimal use of natural gas storage to meet the fluctuating demand of customers, or measuring the financial value of flexibility offered under long-term purchase contracts, or valuing a potential investment in a new pipeline. His regulatory expertise focuses on the liberalisation of the gas industry, particularly its rules for third-party access to pipelines, and its effects on commercial gas operations. He has considerable experience with the electricity industry, which natural gas companies find useful to tap when assessing future developments in the European power market and their likely impact on natural gas markets. Mr. Lapuerta has presented expert witness testimony on behalf of companies in disputes over the market price of gas and concerning the economic rationale for particular clauses in long term contracts. Mr Lapuerta has degrees in law and economics from Harvard University.

Disclaimer

This presentation is meant to provide an insight into current and future developments in European gas markets. Although we believe that the presentation reflects a correct view of the current situation and future developments in these markets at the time of its drafting during late 2004 and January 2005, the authors of this paper and/or Morten Frisch Consulting (MFC), The Brattle Group Inc and The Brattle Group Ltd. cannot be held responsible if this should prove not to be the case or if any of the conclusions drawn from this presentation should prove to be inaccurate. No representation or warranty is made as to the accuracy or completeness of the presentation and no person is entitled to rely on its contents.

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Abbreviations

BBL = Pipeline interconnector from Bacton in the United Kingdom to Balgzand in the Netherlands.

Bcm = billion cubic meters.

DG TREN = the European Commission's Directorate General for Transportation and Energy.

EIA = the Energy Information Administration of the United States Department of Energy.

EU 15 = the first fifteen members of the European Union

mBtu = million British thermal units.

Mt = million tonnes.

NBP = the National Balancing Point in the United Kingdom's pipeline network.

Sm3 = a standardized cubic meter of pipeline-quality gas with gross calorific value of 39 MJ.

ToP = Take-or-pay, referring to purchase commitments in gas sales agreements.

TTF = the Title Transfer Facility, the national balancing point in the Dutch pipeline network.

Executive Summary

To date, the Far East has been the primary market for Arabian Gulf LNG, currently produced by Abu Dhabi, Oman and Qatar and in the future also by Iran and Yemen. However, several developments in recent years point to the growing importance of Europe as an export market. Recent developments include serious price reductions in Asian markets, forecasts for significant increases in European gas consumption over the next two decades, and a forecast reduction in European natural gas production. This reduction is likely to occur while Europe's current main external source of gas, Russia's Gazprom, faces increasing problems in maintaining the gas production level required to fulfil its long-term gas export obligations, and in the operation of its transportation systems including pipelines in transit countries such as Belarus and the Ukraine.

Gas consumption will also increase in the United States as gas production declines in the lower 48 states. However, serving the US market will involve significantly higher shipping costs than serving Europe. Furthermore, environmental restrictions raise major questions about the ability to construct new LNG terminals that can serve the US market. Alaskan and Canadian pipeline gas may even displace the need for a further expansion of LNG imports to the lower US 48 states beyond the total of the LNG capacity in operation, under construction and permitted for construction. In contrast, several European countries have recently allowed the construction of new LNG terminals or the expansion of existing terminals. Arabian Gulf LNG producers have already become involved in some of these projects. The participation of Arabian Gulf LNG producers in all aspects of the European gas market represents the commencement of a trend that should continue.

Successful participation in the European market will require careful analysis of the supply and demand in specific countries, their pipeline interconnections, gas quality constraints, availability of storage for pipeline quality gas as well as for LNG and, last but not least, regulatory developments. For example, the Iberian Peninsula has demonstrated a favourable regulatory environment for the construction of new LNG terminals. However, the Peninsula has recently secured adequate gas supplies for the next few years, and current limitations in the pipeline capacity to France will prevent the short-term development of any significant export potential in the form of pipeline gas to other European countries. The existing LNG supply contracts to Spain permit the diversion of significant volumes to other destinations, protecting existing gas suppliers from the potential emergence of excess capacity. The structure of these contracts indicates that gas suppliers view excess capacity as a real danger.

In contrast to the relative isolation of the Iberian Peninsula, strong links exist between gas markets ranging from the United Kingdom to Italy. Italy is a logical place for the construction of new LNG terminals, because of its proximity to the Arabian Gulf as well as competing gas supplies in the form of pipeline gas and/or LNG from Egypt, Libya and Algeria, and because of the significant pipeline capacity that currently links Italy to other European countries such as Austria, France, Germany, the Netherlands and Switzerland. LNG supplies could serve south east and central Germany as well as other countries indirectly through Italy, by prompting a reduction in the transit flows that currently originate from or pass through these countries into the Italian market. To date, two factors have inhibited Italy's potential as an outlet for Arabian Gulf LNG, but both factors are in a state of flux. First, environmental restrictions have posed difficulties to terminal developers in Italy. Second, serving central Europe successfully through Italy will require progress in the liberalisation of natural gas markets in destinations like Germany and France.

Like Italy, the United Kingdom lies at one geographic end of Europe, but already has a significant link to major European markets through the Bacton-Zeebrugge interconnector to Belgium, and will soon develop another with the completion of the Balgzand to Bacton or BBL pipeline from the Netherlands. The United Kingdom does not enjoy Italy's geographic proximity to the Arabian Gulf, but the UK's favourable regulatory environment and its impending natural gas shortage have provided significant offsetting advantages.

We have analysed the supply/demand balance in Northwest Europe including Spain, Italy and the United Kingdom. Despite the long-term promise for Arabian Gulf LNG, we see some significant short-

term risks. Prices may fall significantly for a period of up to five years, commencing around 2007. Continental Europe will in this period witness gas supply pressure from both the North and the South.

The completion of major infrastructure projects in the United Kingdom should prompt re-exports to continental Europe, and Italian supply should independently exceed demand without the major participation of Arabian Gulf LNG. Northwest Europe already has a slight excess of supply relative to demand, but this has not affected prices in part because of its moderate size and in part because of the existing regulatory environment. As the excess supply grows, and as regulators take pro-active measures to increase competition, Europe can witness serious price declines. Price reductions will extend to long-term contracts signed well prior to the shift in the supply/demand balance. In Europe, typical long-term supply contracts involve several risks for the producer including market-based pricing or price clauses including price review and re-opener provisions, and commercial force majeure clauses. In addition, we can anticipate changes in the ways of structuring new contracts, including delivery flexibility provisions, the take-or-pay clause and the pricing methodology.

A typical response to the threat of excess supply involves the cancellation or delay of new infrastructure projects. However, in this case it would not seem best to delay or cancel projects involving exports of Arabian Gulf LNG to Europe. Regulatory uncertainties are too great. The United Kingdom is now permitting the construction of new terminals. This willingness to allow new permits is at least in part the result of a political fear that gas supply shortages could develop, but there is no guarantee that the current favourable regulatory environment for terminal construction will continue in the future. Furthermore, prices can decline significantly from current levels without destroying the economics of new LNG-based gas supply projects in Europe. The markets for natural gas liquids or NGLs removed from the liquefaction feed gas and the liquefaction process themselves make important independent contributions to the economics of LNG projects. It seems prudent to proceed with investments while the construction and regulatory environments are favourable, and to design commercial strategies that will help protect investments against adverse shifts in the North West European gas supply/demand balance while securing at the same time as longer term market positions. Furthermore, banks that provide loan capital for projects forming part of LNG supply chains, and the rating agencies these banks rely on when evaluating risks associated with such finance packages, are all becoming concerned about the need for LNG project promoters to mitigate downstream gas market risks.

We discuss a three-step commercial strategy to mitigate gas supply risks in North West Europe:

- a) Developing a gas sales portfolio that mixes long-, medium- and short-term gas supply contracts with spot sales;
- b) the development of independent gas trading capabilities, including hedging capabilities;
- c) a strategy of serving European markets from different geographic locations that can be pooled to satisfy gas supply commitments and to support spot sales and trading while maximising gas netback values in the Arabian Gulf.

Arabian Gulf LNG in the International Gas Trade

Cedigaz has estimated that the international gas trade grew by 7.1% between 2002 and 2003, to 761.5 billion cubic metres (Bcm) ¹ expressed in units of standard cubic metres of pipeline quality gas with a gross calorific value of 39 MJ (Sm³). This growth, which continued in 2004, has been the result of improved economic climates in a number of regions, combined with increasing gas requirements outside North America resulting from higher than expected oil prices and a fall in gas production in the lower 48 states of the USA, prompting increased US imports.

Gas trade in the form of LNG rose by an impressive 12.1% to 168.8 Bcm in 2003. This corresponds to 125 million tonnes (Mt) of liquefied product, of which the USA imported some 9%. US imports more than doubled from 2002 to 2003.

During 2003 and 2004 the sheer availability of LNG constrained the growth of global LNG trade. Constraints should last another year, even though global liquefaction capacity in 2005 is estimated to increase by some 23 million tonnes (Mt) ², more than 30 Bcm/y of pipeline-quality gas. LNG shipping and terminal receiving capacities are currently expanding more rapidly than liquefaction capacity. Receiving capacities are projected to be adequate for the available quantities of LNG in the short term.

Figure 1: International Sea-Borne LNG Trade (2003, bcm)

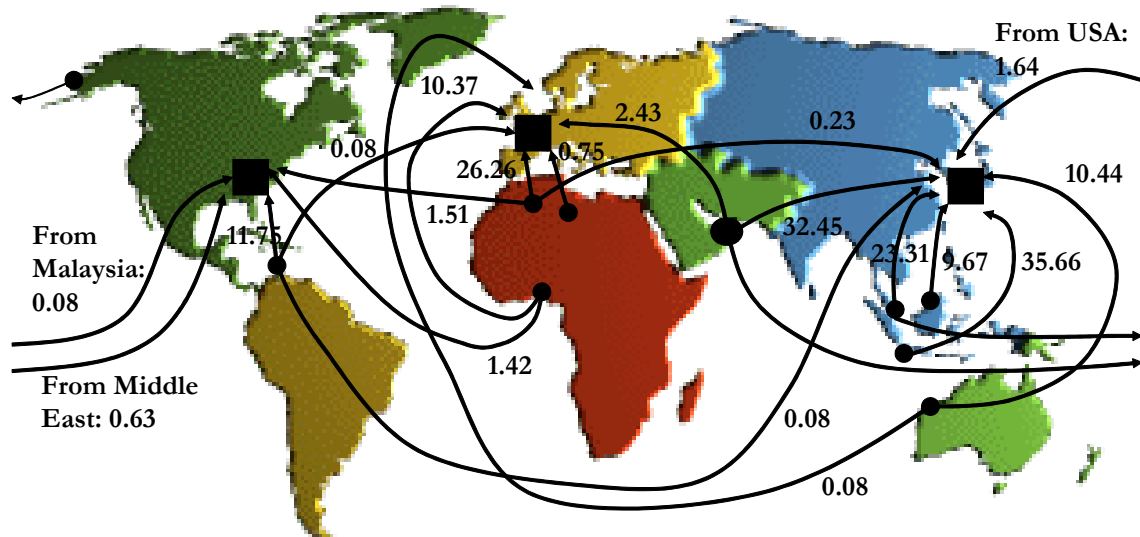


Table 1: World LNG Trade in 2003 (Bcm)

		From											
To	Middle East			Asia-Oceania		Other Exporters *	Total Imports	% Change on 2002					
	Abu-Dhabi	Oman	Qatar	Indonesia	Malaysia								
North America USA**		0.24	0.39		0.08	14.68	15.39	116%					
Europe	0.24	0.32	1.87										
Belgium									3.15	3.15	-8%		
France									9.87	9.87	-14%		
Italy									5.52	5.52	-5%		
Spain & Portugal									13.46	15.89	24%		
Turkey & Greece	5.54	5.54	-5%										
Asia-Oceania	6.87	2.16	9.05	24.05	16.72	20.92	79.77	10%					
Japan									6.93	3.79	1.14	26.23	9%
South Korea									4.68	2.80		7.48	4%
Taiwan													
TOTAL EXPORTS	7.11	9.21	19.19	35.66	23.39	74.28	168.84	12%					

* USA, Trinidad & Tobago, Algeria, Libya, Nigeria, Australia, Brunei and Japan.

** Including Puerto Rico and Dominican Republic.

1 m3 liquid = 0,45 ton = 561 Nm3=593 Sm3

Source: Natural Gas in the World - CEDIGAZ 2003.

Figure 1 above shows international LNG flows in 2003, and Table 1 summarises the information, expressed in billion Sm³ of pipeline quality gas. One can see from this table that Abu Dhabi, Oman and Qatar exported in total 35.5 Bcm of gas in the form of LNG in 2003, representing 21% of the total international sea-borne LNG trade. In the future, these three countries are likely to be joined by Iran and Yemen as the fourth and fifth LNG exporters in the Arabian Gulf area. For the purposes of this paper, "Arabian Gulf LNG" will include present and/or future LNG exports from Abu Dhabi, Iran, Oman, Qatar and Yemen. LNG exports from the Arabian Gulf area are projected to increase very substantially over the next ten years. Increased volumes will in particular come from Qatar but also from Oman and potentially from Iran and Yemen. If all currently planned liquefaction projects should materialise, then the Arabian Gulf area could potentially produce in excess of 130 mt/y of LNG equivalent to export of some 170 Bcm/y of pipeline quality gas by 2015.

Table 2: Asian LNG Price Developments (4th Quarter 2004)

Supplier	Buyer	C.I.F LNG Price (\$/mBtu)
<u>New Contracts*</u>		
India (Reliant)	India (NTPC)	2.70
Australia (NWS)	China (CNOOC)	2.80
Qatar (RasGas)	India (Petronet LNG)	2.80
<u>Traditional Contracts**</u>		
Various	Average Japan (Nov)	5.45
Various	Average Korea (Oct)	6.37

* Source: Petroleum Intelligence Weekly, Issue 5 July 2004.

** Source: Petroleum Intelligence Weekly, Issue 19 January 2005.

As is evident from Table 1, most Arabian Gulf LNG was in 2003 delivered to Japan and South Korea. This was also the case in 2004 when India became a new customer. The audience might ask why we address the North-West European gas markets at this conference. Table 2 above, "Asian LNG Price Developments", indicates that recent long term agreements for the supply of LNG to India and China

have c.i.f. prices in the range US \$ 2.70 to US \$ 2.80 per million British thermal unit (mBtu). We understand that these prices in effect have been frozen for up to five years. This is in sharp contrast to the traditional contracts with Japanese and Korean buyers, which have prices linked to the price of crude oil. In early 2004 these contracts on average had c.i.f. prices of less than 5 US\$ per mBtu³. The current high level of crude prices has raised these average gas prices to some US\$5.45 per mBtu in the case of Japan for deliveries during November 2004, and US\$6.37 per mBtu for Korean deliveries during October 2004⁴. These high average price levels are likely to continue in 2005.

The price disparity outlined above has placed strain on old long-term LNG supply arrangements with Japanese, South Korean and Taiwanese buyers. Older LNG supply agreements between Arabian Gulf LNG producers and their traditional Far-Eastern buyers might not be renewed upon expiry. This situation, and the increased attractiveness of gas markets in the Atlantic Basin to Arabian Gulf LNG producers, is together drawing LNG marketing efforts of LNG away from Asia. Many LNG sales negotiations are currently taking place between Arabian Gulf LNG producers on the one hand and North American and European buyers on the other. Arabian Gulf LNG producers are at the same time investing or planning to invest heavily in North American and European LNG receiving terminals.

The North American Market Option

Forecasts indicate the scope for significant increases in LNG exports to the United States in particular, but also to the Bahamas, Canada and Mexico. Developers have proposed approximately forty different projects to construct new LNG terminals that could serve the United States. We have analysed the US gas market situation, and conclude that the demand projections are likely too optimistic. We see tension between the twin assumptions that support the LNG forecasts: high prices and expanding gas demand. High US gas prices have caused demand to stagnate over the past five years. Forecasts indicate that high prices will continue. The high prices seem logical given the increased costs of supply. Demand will no doubt expand, but we have serious questions concerning the reliability of the forecasts that dominate industry discussion: those prepared by the US Energy Information Administration (EIA). For example, the EIA's projection for gas demand in 2015 has fallen by more than 100 Bcm/y since 2001, a trend that is likely to continue in the future due to inter-fuel competition. In the short term this competition is, in particular, expected to come from fuel oils while in the longer term coal could be the fuel competing most aggressively with gas. Another important factor is "demand destruction", which describes the negative impact that high gas prices have on the chemical industry, the largest industrial gas consumer in the US. One by one fertiliser and petrochemical plants are closing in the US while new capacities are being constructed in areas with plentiful and low-cost gas supplies such as the Arabian Gulf area and Australia. This situation is augmented by the gas burn of the US power generation industry. The high cost of natural gas coupled with US low electricity prices are keeping most new gas-fired power plants idle, because they are too expensive to operate. Gas demand by US power generators decreased by 13% in 2003, while their demand for fuel oils increased by 40%. In the longer term coal is likely to play an increasingly important role in the US as a primary fuel for steam rising in general and power generation in particular.

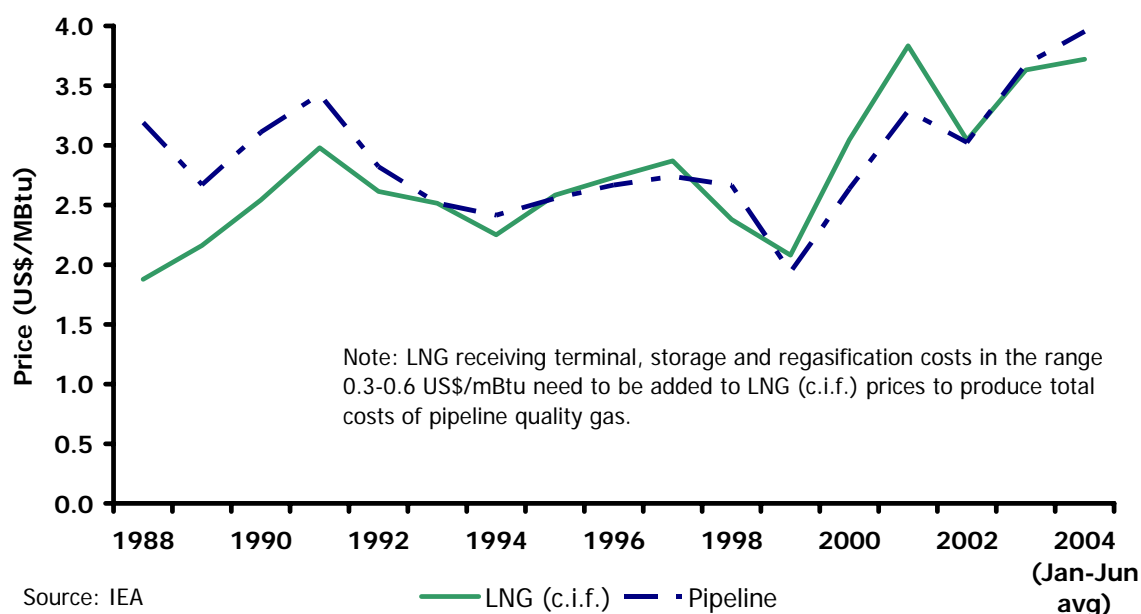
Another development that likely will impact on LNG demand in the US involves the timing and extent of Alaskan and new Canadian gas supplies by pipeline to markets in the lower 48 states. The Alaska Highway Pipeline Project from Prudhoe Bay and the Mackenzie Valley Pipeline from Canada could at their peak supply 80 Bcm/y, equivalent to some 10% of total US gas demand in 2015 based on the latest, but in our opinion still optimistic, demand projection from the EIA. The cost of imported energy is becoming an ever increasing burden on the US balance of payments. Pipeline gas from Alaska should be the gas supply of choice for the lower US 48 states.

Based on the above considerations, a likely scenario is that in addition to the existing four LNG terminals in the US only ten of the forty proposed grass-root projects will proceed, and that the US will still have significantly more terminal capacity than needed through 2015. Prices in US gas markets will likely demonstrate significant volatility, at times dipping low enough to prompt LNG producers in Europe, Africa and the Arabian Gulf area to divert cargoes to Europe, or merely to stop cargoes in Europe on their planned voyage to North America.

The European Gas Market

The historical LNG and pipeline gas import price data presented below in Figure 2 for the first fifteen European Union member countries (EU 15) indicates that the European gas market is becoming increasingly attractive to Arabian Gulf LNG producers. These prices approached 4 US\$ per mBtu at the beginning of 2004 while the average EU 15 border price during 1st quarter 2005 is expected to reach 5.50 to 6 US\$ per mBtu. At this level the European price is approaching the c.i.f. price under traditional long-term contracts for the supply of LNG to Korea and Japan. As a result the quantities of Arabian Gulf LNG that in the future will be destined for the European gas market are likely to increase substantially. A high number of medium and long-term LNG sales contracts are either in place or being negotiated between Arabian Gulf LNG producers and European buyers. Arabian Gulf LNG producers are at the same time investing heavily in European LNG receiving terminals. Up to 45 Mt/y of Arabian Gulf LNG, equivalent to some 60 Bcm/y of pipeline quality gas, could, in ten years' time, potentially be destined for European markets.

Figure 2: Average EU 15 LNG and pipeline gas import prices

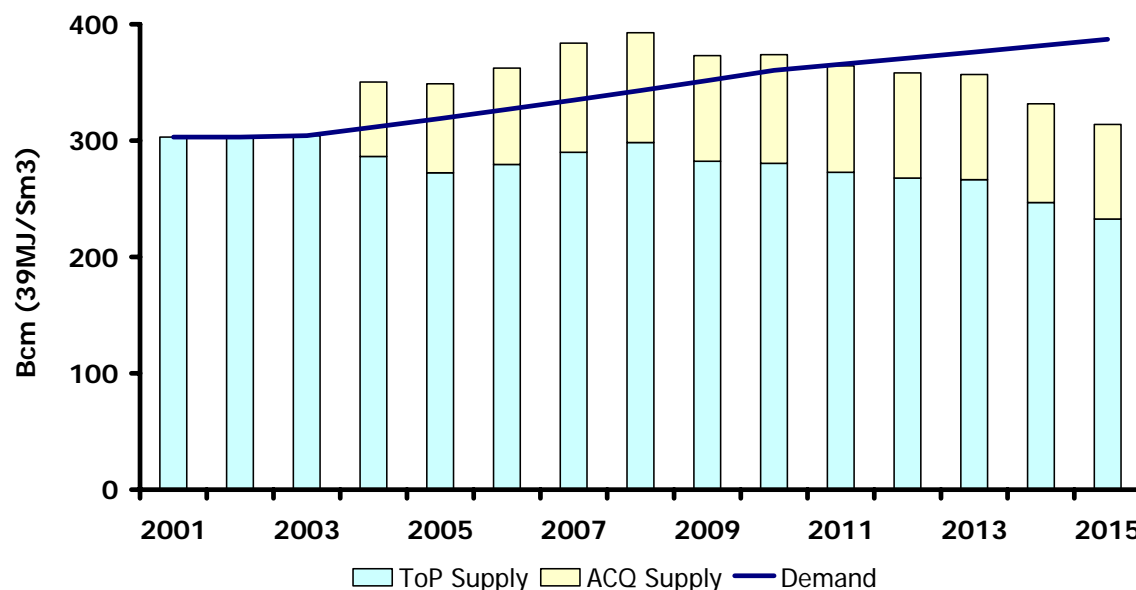


One could argue that Arabian Gulf LNG exporters already have a risk-management system in place. When European gas markets were over-supplied in 2003 and 2004, surplus quantities of LNG were diverted to markets in the Far East and North America. To some extent, this is also likely to happen in the future. However, diversions of cargoes to Far-East markets will become more difficult. Some of the advanced new infrastructure required along the LNG chain to move large quantities of LNG from the Arabian Gulf area to Europe will impede cargo diversions. Gas quality constraints in European gas markets may pose further complications. It is therefore imperative for Arabian Gulf LNG producers to focus on the structure of their European gas supply operations. Alternative operational structures can seriously affect the netback value from the delivery of gas to Europe.

We now turn to the gas market in North West Europe, by which we mean Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Sweden and the UK. Based on gas demand projections published by the European Commission's DG TREN⁵ for each country in North West Europe, we develop projections to 2015 for the balance between gas demand and supply for each country as well as North West Europe as a whole. We forecast gas supply by analysing domestic production within each country together with pipeline and LNG imports for the country concerned.

We consider both annual contract quantities (ACQs) and delivery flexibilities expressed as take or pay (ToP) levels. The difference between ACQ and ToP levels indicates the supply flexibility for each country as well as the whole market area represented by North West Europe. As is the case in the European gas market at present, long distance gas pipeline supplies have been assigned a high ToP level reflecting the base-load nature of these contracts. For LNG receiving terminals ACQs have been set at 90% of the design capacity while ToP levels reflect the ability to divert LNG cargoes to markets outside Europe.

Figure 3: Gas Supply and Demand Balance in North West Europe (ACQ and ToP)



Note: North West Europe includes Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Sweden and the UK

Figure 3 above shows the gas supply and demand balance for North West Europe expressed as ACQ as well as ToP. Two countries in North West Europe, Belgium and France currently import gas in the form of LNG while the UK will most likely become an LNG importer again in 2005. A total of three LNG terminals are under development in the UK while an expansion project is taking place at the Belgian terminal at Zeebrugge. New terminal projects are planned for France.

When preparing the gas supply and demand balance shown in figure 3 we assumed ToP levels of 50% ACQ for the terminals in Belgium and the UK, while assigning ToP levels of 75% ACQ to the existing LNG terminals in France. The different ToP levels reflect the greater likelihood of diverting cargoes away from Belgium and the UK. We see less scope for diverting cargoes from France, where LNG should play a more important part of base load supply.

Our analysis suggests that North West Europe as a whole is likely to have a balanced position between projected demand and supply over the next few years. The demand curve for this gas market area intersects supply at a level between ACQ and ToP until 2010/2011. However, the situation within the North West European gas market area itself is far from homogeneous, and Italy and Spain located outside this gas market area are developing substantial gas oversupply situations.

We address the situation in Spain first. The Spanish gas market is integrated with that of Portugal. The two countries together form the Iberian Peninsula. Figure 4 below shows the Iberian gas supply and demand balance, indicating that Iberia was already in a ToP paying position in 2004. We project

Figure 4: Iberian (Spanish + Portuguese) Gas Demand and Supply Balance (ACQ & ToP)

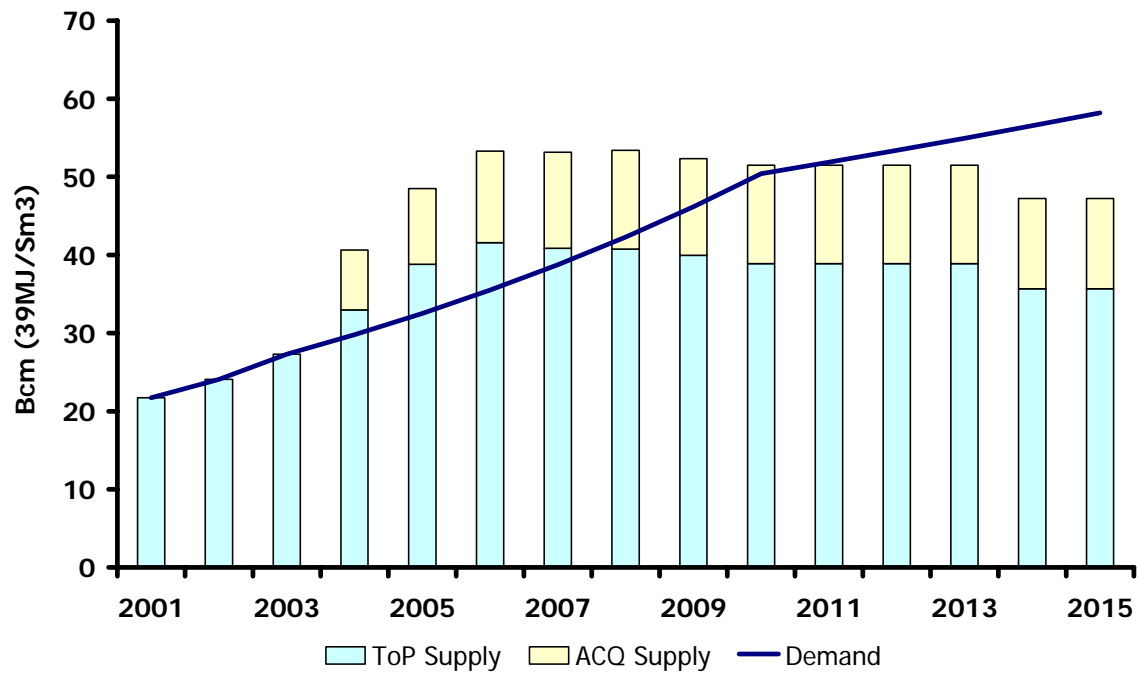
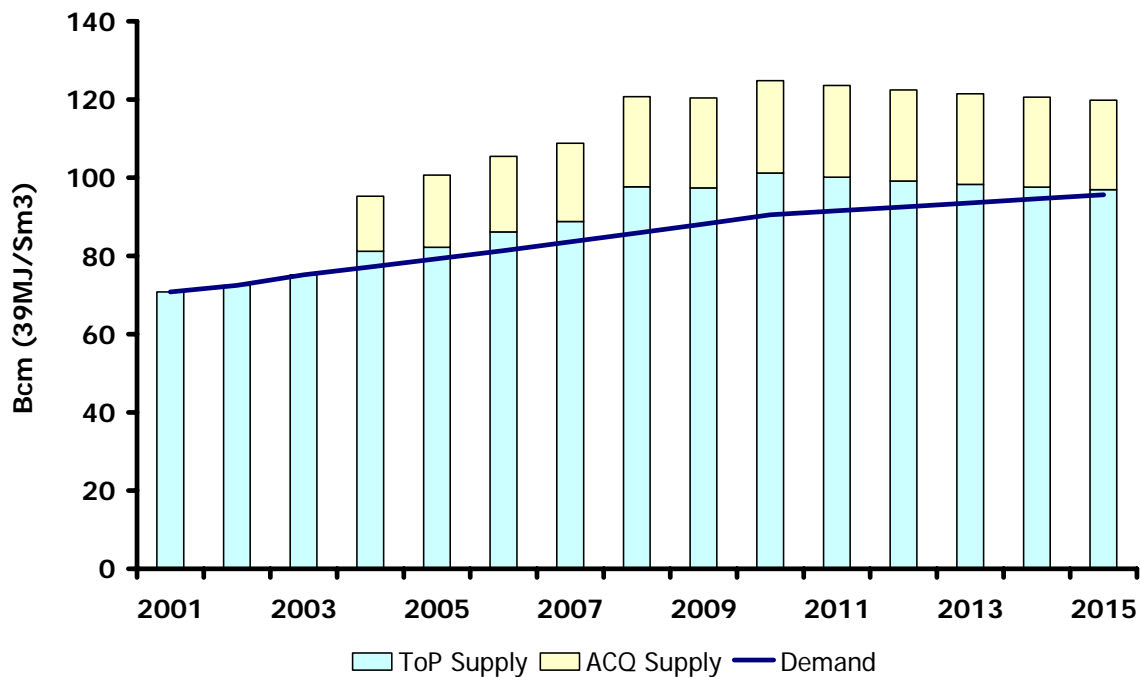


Figure 5: Italian Gas Supply and Demand Balance (ACQ & ToP)



a significant gas surplus lasting until 2008. Construction of the second gas pipeline between Algeria and Spain, Medgaz, which now seems likely⁶, would prolong this surplus by 2-3 years.

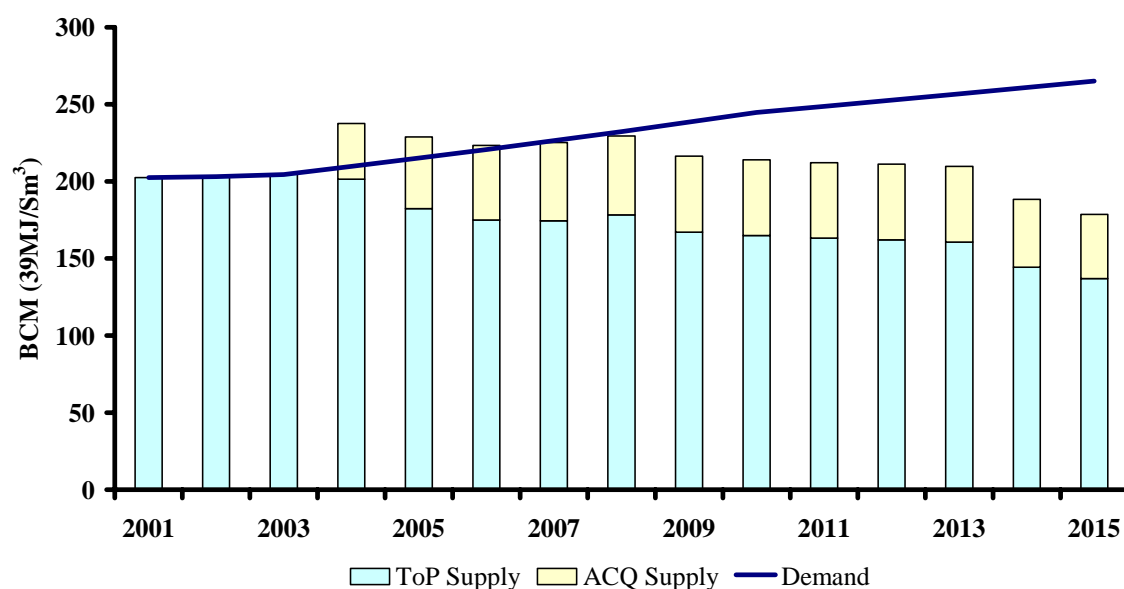
The Iberian gas market area does not have the ability to re-export surplus gas quantities by pipeline, due to the limited pipeline capacity that currently interconnects the Spanish gas market with that of France to the north. However, Spain is in a unique position in Europe since it currently has contracted approximately 75% of its gas supply, based on ACQs, in the form of LNG. Spain and the Iberian Peninsula are therefore likely to adjust their market positions through the onward sale of LNG cargoes. Indeed, in total, Spanish LNG contracts have the flexibility to re-sell the equivalent of 10 Bcm of pipeline quality gas on a yearly basis⁷. The Spanish oversupply together with this flexibility could in turn influence gas markets in North West Europe, as well as Italy, if LNG terminals in these two geographic areas should be the only viable outlets for Spain's surplus LNG cargoes. However, due to the current shortage of LNG we believe that this situation should commence during 2006 at the earliest.

We forecast a large gas surplus in Italy as well. Figure 5 above shows that Italy already might have confronted ToP problems during 2004, a situation that could continue beyond 2015. European transit pipelines serving Italy pass through Austria, Germany, France and Switzerland. Italy could reduce its imports by re-selling surplus gas quantities to these countries via backhaul. This has already to some extent happened with gas destined for Italy being delivered to Germany.

Italy currently has one small LNG terminal. The construction of a second terminal is due to start shortly while two further terminals have obtained or are in the process of obtaining the necessary consents for construction. The analysis presented by Figure 5 has included the ACQs for three LNG terminals at Panigaglia, Brindisi and Rovigo, including their planned extensions. The political climate at a national level in Italy is currently positive for the construction of additional LNG terminals. With a further seven to eight LNG import terminals being planned it is therefore possible that Italy in total could have four or five operational terminals by 2010.

Italy would prove an especially attractive place for Arabian Gulf LNG producers to deliver cargoes on a regular basis or to divert cargoes destined for terminals further to the west in the Atlantic Basin. Italy's geographic proximity to Arabian Gulf sources of LNG would prompt significant savings in shipping costs, and Italy's backhaul possibilities with countries to its north and west would create the possibility of serving a broader continental European market.

Figure 6: North West European Supply and Demand Balance (excluding UK and Ireland)

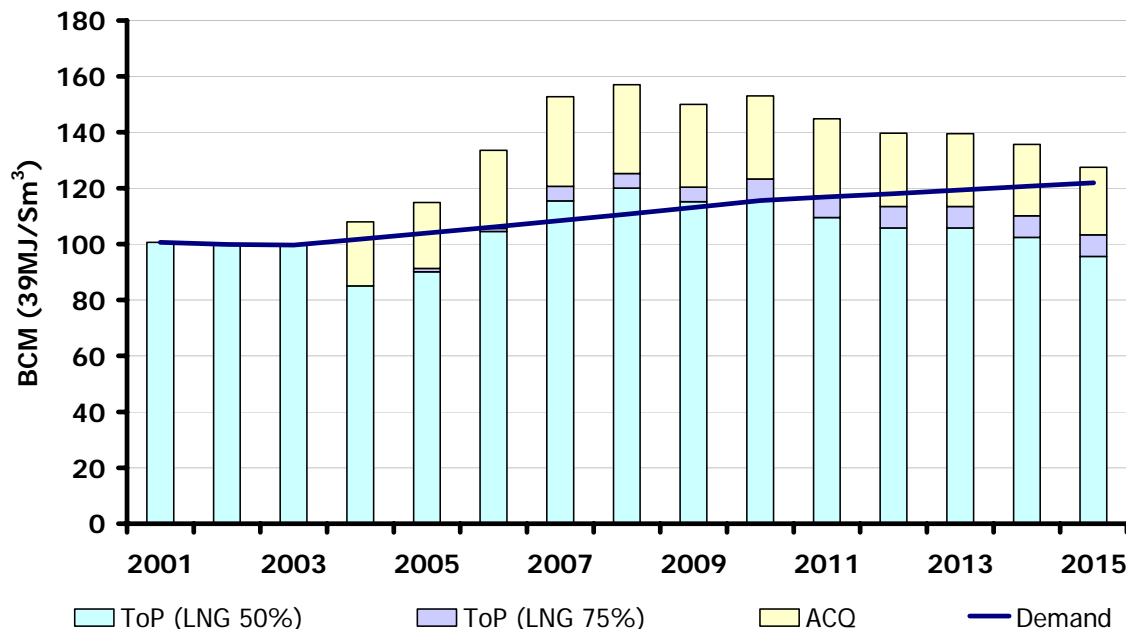


Note: North West Europe includes Belgium, Denmark, France, Germany, Luxembourg, Netherlands, and Sweden.

We now return to the gas supply and demand balance in North West Europe. Figure 6 above presents the balance for this gas market area less the UK and Ireland. Based on average ACQs, the continental European part of North West Europe is projected to require additional gas supplies already in 2007. This is in sharp contrast to the market area represented by UK and Ireland as shown in Figure 7 below. We predict that already in 2006 this part of North West Europe may start to encounter ToP problems, a situation that could last until 2010 assuming that LNG terminals in the UK are operated at a ToP level of 50% ACQ. Should ToP for LNG imports be set at 75% ACQ then our analysis shows that this problem could continue until 2011.

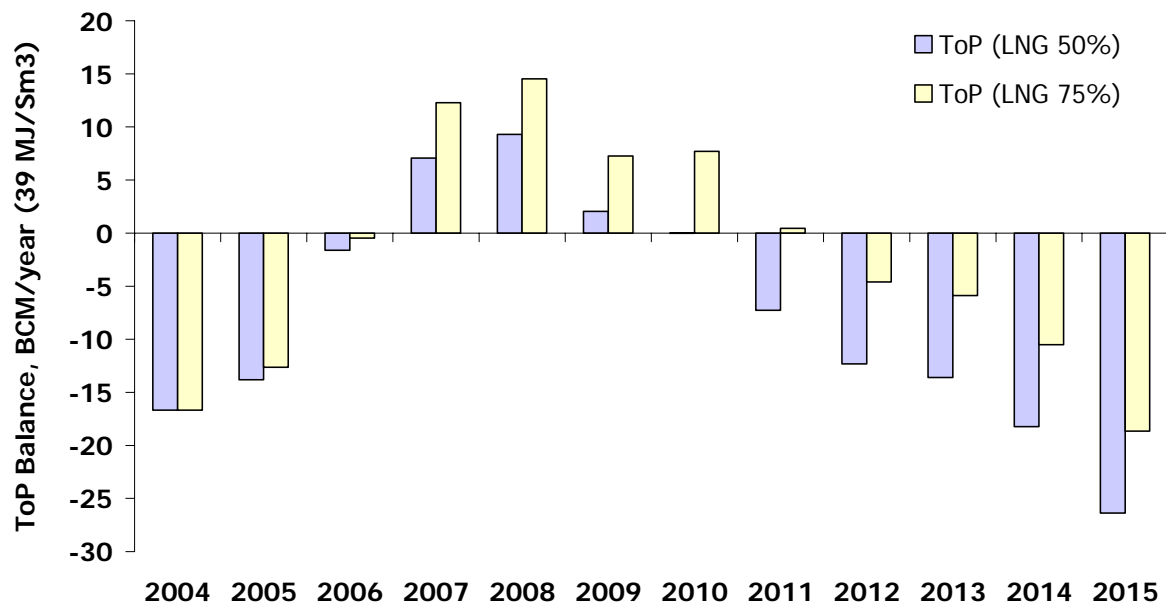
The gas market in the UK is fully liberalised, and gas supplies entered into after 1996 have in effect been priced in accordance with the spot price or forward price curve at the national balancing point or NBP of the pipeline network. Figure 8 below shows the magnitude of the total ToP problem for UK and Ireland under alternative assumptions that LNG receiving terminals have ToP levels equal to 50% or 75% of their ACQs.

Figure 7: UK and Ireland Gas Supply and Demand Balance, ACQ & ToP (ToP 50% and 75% for LNG)



At a lower ToP level we estimate the gas supply surplus for the UK and Ireland gas market area at 7 Bcm and at a higher level above 12 Bcm, both in 2007. This surplus is, in effect, the UK gas supply position after exports to Ireland. It represents between 6% and 12% of UK gas demand. Past experience in the UK market has shown that a developing surplus of this magnitude exerts a major downward adjustment in NBP gas prices. The gas surplus and deficit for the UK and Ireland shown in figure 8 suggests a commencement of this process during the second half of 2006, manifesting itself properly during the spring of 2007. Nominal prices at NBP could fall from a current (Feb-05) level of US\$5.50 per mBtu to some US\$ 3.20 to US\$3.80 per mBtu reflecting the marginal cost of LNG supplies to terminals in England.⁸ As indicated earlier, our analysis assumed that 50% ACQ of LNG terminal capacity in England can be diverted elsewhere. If less than 50% ACQ can be diverted e.g. the 75% ACQ ToP case discussed above, perhaps in part because price declines in the US market limited the amount of LNG cargo diversions there, then UK NBP prices could fall to even lower levels.

Figure 8: UK and Ireland Gas Surplus/Deficit (ToP)



Negative value indicates deficit.

There will be three LNG receiving terminals under construction in the UK in 2005. They are Dragon LNG and South Hook LNG in South Wales and Isle of Grain LNG south east of London. Figure 9 below shows the position of these three terminals in relation to North West European natural gas infrastructure and gas trading hubs. The United Kingdom already has a significant link to the continental North West European markets through the Bacton-Zeebrugge interconnector to Belgium, and will soon develop another with the completion of the Balgzand to Bacton or BBL pipeline from the Netherlands scheduled for early 2006. The gas surplus developing in the UK after exports to Ireland in 2006/07 will be exported to Belgium and the Netherlands through the Bacton-Zeebrugge interconnector and the BBL pipeline respectively. This process will start when the price for gas at the NBP has fallen to a level below the price levels at the Dutch gas balancing point, called Title Transfer Facility or TTF, and/or the Zeebrugge Hub in Belgium that makes gas supplies from the UK attractive at either of these trading hubs after transportation charges. As demonstrated by figure 6 above, a market for the UK surplus is projected to develop in continental North West Europe after 2007.

Figure 9: North West European Natural Gas Infrastructure



Price Review and Price Re-opener in a Changing Market

Gas price fluctuations caused by oversupply and gas-to-gas pricing in the UK market are likely to have consequences for the continental “legacy contracts”, which are long term contracts with prices indexed to petroleum product prices. When gas prices in the UK market fall below those in continental North West Europe due to oversupply, surplus gas quantities will be exported to the Belgian and Dutch gas markets as outlined above. If gas prices in the Belgian and Dutch gas markets should reflect a lower UK price level over an extended period of time, we would expect buyers to invoke price review and price re-opener clauses in continental legacy contracts for the supply of Dutch, Norwegian and Russian gas. Below we explain the operation of price review and price re-opener clauses in continental European legacy contracts, to demonstrate the forces that a gas surplus in the fully-liberalised UK market can unleash.

Price review and price re-opener clauses were introduced into Continental North West European contracts in the early 1980's. During the late 1970's the price adjustment mechanisms in gas contracts had failed to capture fully the rapid increase in the value of liquid hydrocarbons products. At the same time both gas producers and their customers observed that price adjustment clauses normally functioned as planned for no more than some three years. They recognised the potential need to adjust or possibly change the base price and also the indexation in price adjustment formulae at regular intervals during the life of long-term gas supply arrangements. The oil price crash in the second half of 1986 drove home this point.

By the end of the 1980's price review mechanisms had been introduced into new as well as existing gas supply arrangements in the continental North West European market areas. Originally price review and price re-opener clauses could only be triggered every three years but many contracts have now reduced this period to two years due to rapidly changing market conditions. We understand that some gas buyers and sellers are now discussing annual price reviews. To protect the continuity of the seller's operations as well as the buyer's gas supply, long-term gas contracts stipulate that a

price review and/or price re-opener recognition or arbitration shall not in any way disrupt the flow of gas under a gas sales agreement. Delivery nominations and the supply of gas take place in accordance with normal operations under a contract even if the buyer and seller should disagree about the price or go to arbitration.

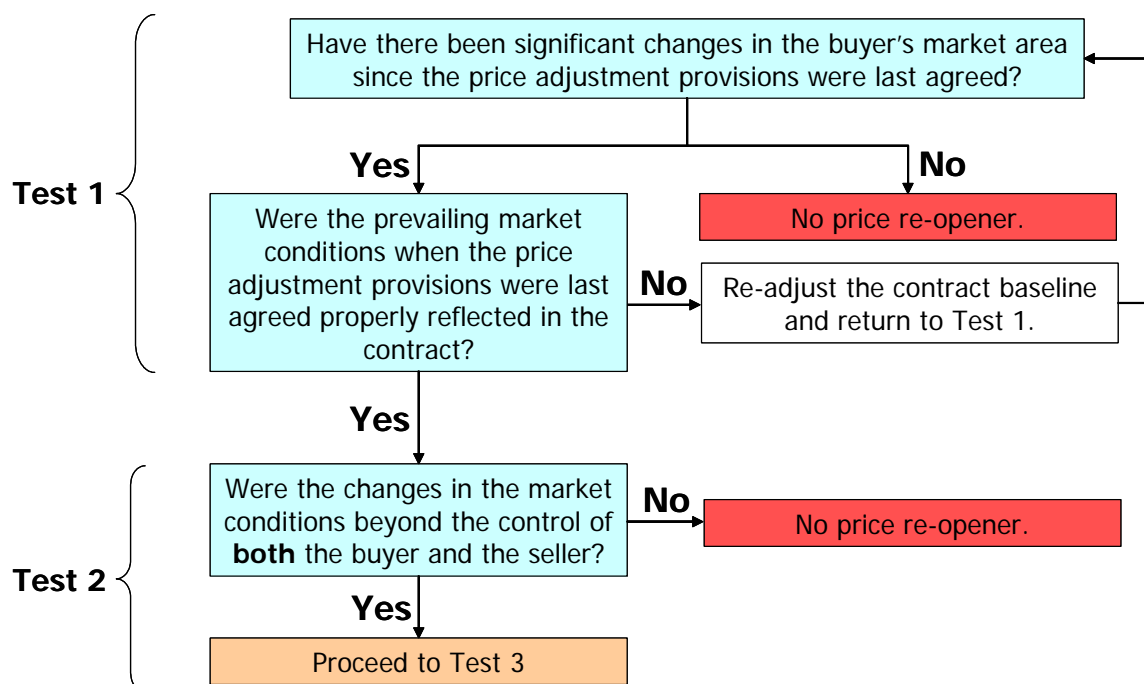
Continental North West European price review clauses are normally based on three main principles. The first of these principles relates to the economic condition or circumstances in the buyer's market area for gas and how these conditions change over time. This first principle applies universally to all gas and its value in the buyer's market area.

The first main principle results in the following two price review tests. It must be demonstrated that:

- (1) economic conditions have changed significantly in the buyer's market area when compared to when the price adjustment provisions were last agreed; and
- (2) the changes outlined in (1) above are beyond the control of both the buyer and the seller.

Satisfying both tests would entitle either the buyer or the seller to an adjustment of the price provisions in the gas sales agreement. In practice the first test has prompted parties to revisit the previous price agreements, with some arguing that the last price negotiation or arbitration result did not reflect prevailing market conditions accurately. Figure 10 shows the various steps of the process.

Figure 10: Two Tests in the Price Review and Reopener Process

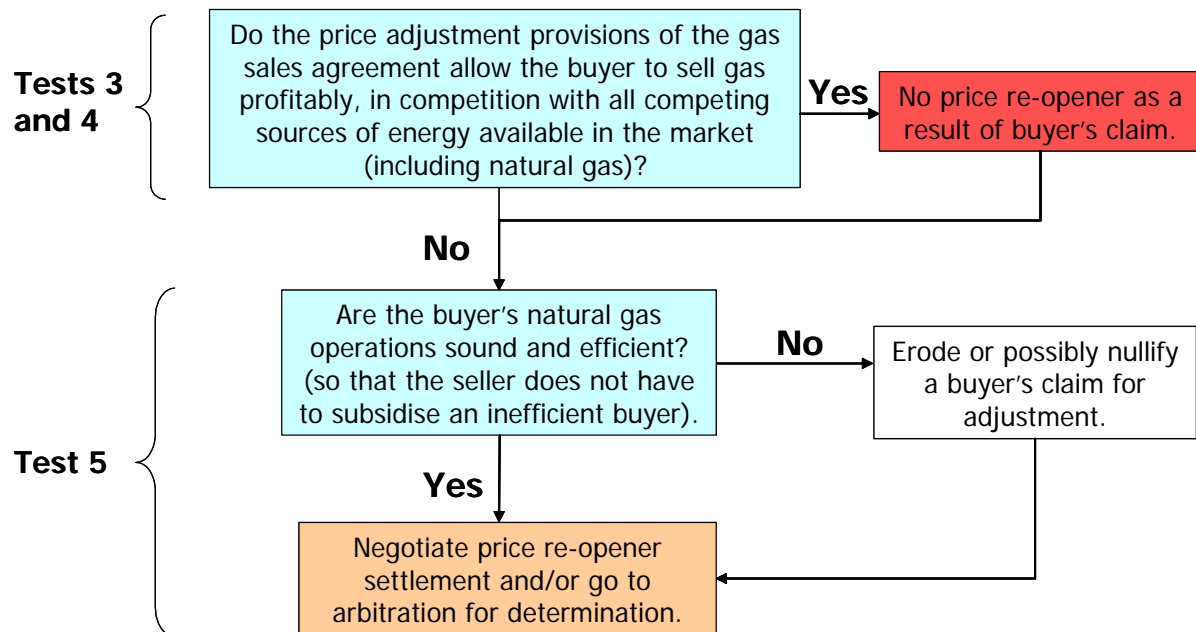


The second main principle relates to the gas delivered under the gas sales agreement in question (the Sales Gas). This principle has been adopted to protect the buyer's market position since no company can operate a long-term gas supply agreement at a loss over a substantial period. It gives rise to the following three tests. It must be demonstrated that:

- (3) the applicable price resulting from the operation of the price adjustment provisions of the gas sales agreement in question allows the buyer to economically market the Sales Gas delivered under the agreement in his natural gas market area;
- (4) the buyer shall, in particular, be able to undertake the economic marketing of Sales Gas under (3) above in competition with all competing sources of energy including natural gas available in the end user market within his natural gas market area; and
- (5) the buyer's gas marketing practices and physical gas operations are sound and efficient when measured against general business standards in the buyer's country as well as against gas companies in the geographic region in which the buyer's natural gas operations are located.

The outcome of the tests which are defined in (3), (4) and (5), overrides the tests as defined in (1) and (2) above.

Figure 11: Buyer's profitability test; decision diagram



Test (4) is essentially a more specific restatement of test (3). Older legacy contracts did not include the third test, and therefore did not state explicitly whether the need to market natural gas economically referred to potential competing sources of natural gas, as opposed to other energy sources. Commercial practice emerged to include the insertion of the fourth test as a clarification. If the buyer can demonstrate that the Sales Gas fails tests (3) and (4) while the buyer satisfies test (5), then the buyer is entitled to an adjustment of the price provisions and/or other commercial provisions in the gas sales agreement that together will rectify the unsatisfactory position of the Sales Gas in the buyer's market. Figure 11 outlines the operation of tests (3), (4) and (5).

The third main principle relates to changes in the tax regime for gas and/or competing fuels in the buyer's market. Taxes and associated tax levels levied on energy are part of the economic conditions or circumstances in the buyer's market. Test (1) would therefore appear to cover taxes, but

continental North West European gas buyers have in some contracts managed to extract separate tax-based price review provisions from their gas suppliers.

A buyer can request a separate price review upon demonstrating that a change in the tax regime for gas and/or its competing fuels has significant negative economic consequences. If tax changes have the opposite effect in the buyer's market—improving the buyer's trading position and/or profit level from the re-sale of Sales Gas, then the seller can request a separate price review.

Some gas sales agreements with continental North West European buyers contain a fourth main price review principle. This fourth principle specifies that the buyer and the seller of the Sales Gas shall share the economic rent generated by the production and sale of such Sales Gas on an equitable basis. This provides a guarantee to the buyer as well as the seller. If the first five tests above have been met in full, then the fourth principle can prevent one party from making an undue profit relative to the other under the gas sales agreement.

Price review based on an equitable sharing of economic rent can be very valuable to the seller during periods of low energy prices. This principle, if adopted, in a gas sales agreement, will prevent the buyer from receiving a guaranteed margin on the Sales Gas at the same time as the seller operates at a loss. To be of maximum effectiveness for the seller, price review provisions based on this principle must override or be allowed to offset the contract specific tests set out in (3) and (4) above concerning the buyer's need to market natural gas economically.

The normal definition of economic rent excludes all taxes levied against the Sales Gas. The government of the buyer's country can therefore introduce a gas tax that reduces the economic rent available for sharing between the buyer and the seller, which could therefore reduce the price that the buyer has to pay for the Sales Gas. It is important to tie the tax-based price review provisions of a gas sales agreement to the treatment of a gas tax and/or similar impost under any economic rent principles mentioned in the contract.

Experience has shown that price review and price re-opener clauses in continental European legacy contracts are most effective during periods of gas oversupply and falling prices. The Buyer's Profitability tests, the operation of which are outlined in figure 11 above, have proved a very powerful tool for gas buyers in the lowering of gas prices in the past. Gas producers and sellers have only infrequently used these clauses successfully to raise prices during periods of scarcity and rising market prices.

The summary above reveals several avenues through which market changes could affect the prices in long-term legacy contracts. To illustrate we discuss the predicted UK surplus. Buyers in Belgium and the Netherlands may witness re-exports of surplus gas from the UK through the Bacton-Zeebrugge interconnector and through the new BBL pipeline, claiming that these re-exports represent a significant change in circumstances that lie beyond their control.

The buyers will cite the downward price pressures in the liberalised market to seek a reduction in the prices in their long-term contracts. Liberalisation has prompted the emergence of spot markets in Belgium and the Netherlands. The export of surplus gas would probably reduce spot market prices significantly. Buyers may claim that they cannot sell the gas economically unless the prices in their long-term contracts fall sufficiently to match the prevailing prices witnessed in the Belgian and Dutch spot markets. If oil prices remain high, buyers may also claim that oil-indexed prices give disproportionate economic rents to the sellers.

Buyers can make claims that are fundamentally mistaken, or that arbitrators may disregard. However, experience indicates that the emergence of a gas surplus will prompt the types of claims outlined above, and that price review and re-opener provisions can subject the seller to significant risks. Sellers cannot trust that the indexation formulae in their long-term contracts will protect them fully from the emergence of a gas surplus, not even over relatively short periods. With the increased frequency of price reviews to two and possibly one-year periods, long-term contracts will offer minimal protection to the seller against a gas surplus.

Conditions for Market-based Changes in Continental North West Europe

Figure 3 above indicates that the gas market area in North West Europe should have a reasonable balance between supply and demand until 2010 or 2011. The surplus gas in the UK should therefore be able to find a home in other North West European countries through delivery by pipelines. This could also be the case for Italian surplus volumes re-exported to other European countries by pipeline backhaul and for LNG cargoes surplus to Spain's needs. However, the ability of the UK, Spain and Italy to export their surpluses will depend to a large extent on progress with gas market liberalisation, and in particular the development of third-party access to pipeline systems in countries such as France and Germany.

If liberalisation does not progress further, then the impact of UK surplus might be limited to the UK, Belgium and the Netherlands. Successful liberalisation in France and Germany will facilitate re-exports of gas from the UK not only to Belgium and the Netherlands, but most likely throughout the whole of the North West European gas market area. Our analyses demonstrate that pan-European gas market liberalisation could mitigate serious price declines in Belgium, Ireland, the Netherlands and the UK while avoiding potential price increases elsewhere in North West Europe.

A failure to implement proper third-party access would leave Italy and the UK in particular, but also Belgium, Ireland and the Netherlands, witnessing significant price decreases already by 2007/08, while other interconnected countries in North West Europe would experience a more gradual price adjustment through the application of price review and price re-opener clauses. This is in particular the case in Germany where the gas market area considered as part of a price review and price re-opener test tends to be restricted to the German national market or even only parts of this. German legacy contracts can therefore to some degree be isolated from gas price developments in the legacy contracts of other European countries that tend to consider energy price developments throughout Western Europe as part of price review and price re-opener tests.

Our experience is that the mere emergence of a surplus in a neighbouring country can create significant political pressure to proceed with liberalisation. If prices fall dramatically in the UK, and German industrial customers are not witnessing the benefits despite the existence of ample export capacity in the BBL pipeline and its connections to the German market, the German government and regulator will no doubt witness increased pressure or receive additional support to reform and improve the third-party access arrangements in Germany. It should not be forgotten that gas bubbles in both the United States and the United Kingdom coincided with the effective implementation of third-party access.

Gas Market-based Risks in North West Europe

The risks of the North West European gas market area could take many forms. The introduction of gas market liberalisation within the 25 countries now constituting the European Union introduces at least five major risk factors.

The first factor is regulatory risk. Liberalisation has already commenced in all European countries, and some countries such as the UK in effect have completed the process. However, history has revealed the unpredictable nature of regulatory implementation. The extent and timing of implementation remains uncertain in different European countries. The only thing we can say with certainty is that liberalisation will present a considerable risk for gas sellers and buyers alike, and that the risk will most likely be concentrated over the next five years.

A key aspect of regulatory risk involves "gas release programmes". All indications are that incumbent gas importers in Italy, Germany, France and probably in other countries have been hoarding gas in order to stave-off the development of competition in their traditional gas market areas. National regulators are likely to force the release of surplus gas supplies on the books of incumbent gas importers and this could lead to a sudden drop in the price of gas within the national market concerned. Gas release programmes have already played an important role in the liberalisation of the

gas markets in the United Kingdom, Spain and Italy.

When a major surplus gas position develops, as is currently the case in Italy, the incumbent gas importer's ToP position may force the release of gas. Signs are that Italy has already started doing this through the backhaul of gas into south-east Germany, an area transited by Italian pipeline imports from the Netherlands. The Italian incumbent is in this instant selling surplus gas to a German company it has ownership interests in.

Another aspect of regulatory risk involves the introduction of proper third-party access to the pipeline systems in Europe. Experience from the United States and elsewhere confirms that access to storage facilities and other sources of flexible gas plays a crucial role in the development of competition. Competitive pressures intensify when all gas suppliers have access to similar resources. Outside of the UK, most European countries still have considerable room to improve the access to storage and line-pack, and to introduce cost-reflective balancing arrangements that allow competitors to incur modest temporary imbalances without incurring unreasonable penalties. Improvements in balancing arrangements and in access to storage and line-pack will likely have positive long-term effects for gas suppliers as well as buyers.

Many legacy contracts have "destination clauses", which are contractual clauses that restrict the resale of gas to destinations other than the points of delivery specified for Sales Gas. The removal of destination clauses will further promote competition and help balance gas supply and demand, stabilising prices across countries. This is particularly the case in North West Europe due to the impending gas oversupply in the UK. Russian contracts for the supply of pipeline gas to France and Germany still have destination clauses, although we understand that the European Commission has declared them unenforceable.

Our second major risk factor is the prospective gas surplus in the fully liberalised UK gas market, which has already adopted gas-market-based pricing, and the prospective surplus in Italy. A surplus in the UK presents a major price risk not only in the UK but also in Belgium, Ireland and The Netherlands due to the current and future direct pipeline connections between these three countries. The UK market in particular is likely to experience price volatility in the short to medium term. Volatility will arise and extend to Belgium and the Netherlands even if proper third-party access is introduced on a European Union wide basis. However, the introduction of proper third-party access is likely to shorten periods of price volatility and to dampen its magnitude. A surplus in Italy will put downward price pressure on interconnected transit markets like France and Germany, but its effect is less clear because of the first risk factor identified above: regulatory risk associated with the progress in gas liberalisation.

We have previously discussed the emerging surplus in Spain. Since so much of the new terminal capacity to Europe will be built in the United Kingdom, France and Belgium, these countries will likely attract diverted cargoes from Spain—particularly at times when prices in the United States are low. Spain already participates actively in Atlantic basin LNG trade, purchasing supplies from Trinidad & Tobago and Nigeria. It may be more economic to divert cargoes from these sources to other terminals on the Atlantic Coast and North Sea, instead of diverting them to Mediterranean destinations. The Algerian gas supplies to Spain will probably divert to Mediterranean destinations like Fos-sur-Mer in France or the Italian terminals. We conclude that the Spanish surplus will likely contribute to the primary risk factor that we have identified of the UK and Italian surpluses.

The third risk factor is represented by continental North West European legacy contracts. The operation of the price review and price re-opener clauses in these contracts represents gas market uncertainty and therefore market risk. The gas oversupply situation and price volatility predicted for the UK market will trigger price review and price re-opener clauses in continental North West European legacy contracts. This will first happen in Belgium and The Netherlands and eventually spread to France, Denmark, Luxembourg and Sweden before reaching Germany. History has shown these clauses to be important tools for lowering gas prices. Frequently the operation of these clauses results in arbitrations. The arbitration process itself represents a risk factor for both the gas supplier and the gas buyer.

We now turn to the operation of gas price adjustment mechanisms. We mentioned earlier the practice of indexing UK gas contracts to the spot price or forward price curve at the NBP. This practice is now also spreading to Ireland, Belgium and The Netherlands. Proper performance of gas-to-gas pricing requires a large number of players and good liquidity at the trading hubs that serve as contractual reference points. Liquidity at the NBP has deteriorated lately, and there have been signs that larger players could influence the market. Hopefully, a large gas oversupply position in the UK will rectify this situation and remove the risk of market manipulation.

Price adjustment mechanisms based on petroleum product-based indices are also becoming far less reliable than they used to be. In Europe, petroleum products are today mainly used as transportation fuels. Consequently, they carry a premium value. The traditional markets for non-transport use of gas oil and heavy fuel oil are disappearing, mainly due to competition from natural gas. Gas oil and heavy fuel oil prices from traditional inland markets are therefore becoming less reliable as statistical sources. Large market players can manipulate prices, as can operators of infrastructure who move these products both within and between European countries.

Gas trading hubs have not yet developed sufficiently to provide reliable price signals and price adjustment data. The relatively slow pace of market liberalisation in many European gas markets has delayed hub development. At the same time, the traditional European oil product markets used as a statistical source for gas price indices are also becoming unreliable. Low reliability will prompt a transition in gas pricing mechanisms. The transition period is likely to last some five years, until full liberalisation accompanied by the introduction of full and effective third-party access to natural gas networks. During the transition, the operation of gas price mechanisms will represent a major risk factor, the fourth such factor on our list.

Our fifth risk factor is the existence and operation of commercial force majeure clauses and force majeure pass-through clauses. Continental North West European gas buyers are becoming more risk adverse. This is particularly the case among new market entrants. When entering into medium and long-term gas supply contracts, as well as the supporting transportation agreements, these buyers insist on the inclusion of commercial force majeure clauses as well as force majeure "pass-through" clauses. The pass-through clause allows a gas buyer to reduce its gas purchase commitment when the buyer itself faces a reduced gas sale due to a force majeure claim from its own customer. For gas suppliers, these clauses can be more disruptive and therefore represent a higher risk than the combination of price review and price re-opener clauses. In the most extreme situation, a commercial force majeure or a pass-through clause can lead to the immediate cessation of the gas supply under a contract.

Mitigation of Gas Supply related Risks in North West Europe

The gas market in North West Europe is evolving. The introduction of proper gas market liberalisation will to a large extent depend on France and Germany, two of the largest gas markets in the area and two countries that play crucial roles as gas transit countries.

We have predicted that part of the North West European market area represented by Ireland and the UK most likely starting in 2007 will have excess gas supply and falling prices. There will also be excess gas supplies in Italy and Spain that most likely in the medium term will look for a home in North West Europe. In spite of these gas supply pressures we predict that the North West European gas market as a whole can be balanced. However, this would require gas market liberalisation and in particular proper third-party access throughout the North West European market area in the near future.

A typical response to the threat of excess supply involves the cancellation or delay of new infrastructure projects. However, in this case it would not seem best to delay or cancel projects involving exports of Arabian Gulf LNG to North West Europe. Regulatory uncertainties are too great. The UK is now permitting the construction of new LNG receiving terminals. This willingness to allow new permits is at least in part the result of a political fear that gas supply shortages could develop as

is threatened in Great Britain for the winters of 2004/05 and 2005/06. There is no guarantee that the current favourable regulatory environment for terminal construction will continue in the future. A similar situation exists in Belgium. A favourable regulatory environment for terminal construction also exists in Spain and Portugal, while it is improving in Italy. Spain, Portugal and Italy lie outside North West Europe but have pipeline or potential LNG links with this gas market area.

Furthermore, wholesale gas prices in North West Europe can decline significantly from current levels, which are approaching US\$ 6 per mBtu, without destroying the economics of new LNG based gas supply projects in North West Europe. The markets for natural gas liquids or NGLs, removed from the liquefaction feed gas and liquefaction process, themselves make important independent contributions to the economics of LNG projects. It seems prudent to proceed with investments while the construction and regulatory environments are favourable.

However, we recommend that Arabian Gulf LNG producers design commercial strategies that will help protect investments against adverse shifts in the North West European gas supply and demand balance, while securing longer term market positions. An important part in developing a new gas supply chain for the supply of LNG to North West Europe or indeed any other market area is to secure financing for all parts of the LNG chain in question. Banks that provide loan capital for projects forming part of LNG supply chains, and the rating agencies these banks rely on when evaluating risks associated with such finance packages, are becoming concerned about the need for LNG project promoters to mitigate downstream gas market risks.

Successful participation in the North West European gas market will first of all require careful analysis of the supply and demand as well as the pricing structure in specific countries, their pipeline interconnection, gas quality constraints, availability of storage for pipeline quality gas as well as for LNG and, but not least, regulatory developments and risks. Analysis should inform the development of a commercial strategy to mitigate gas supply risks in this market. Based on our experience and supported in part by the commercial strategies already adopted by some Arabian Gulf LNG producers, we outline a three-step plan for mitigating gas supply risks in North West Europe.

All three steps below involve the general concept of integrating further down the gas supply chain. Integration reduces the risk of relying on the continued operation of long-term contracts with European gas supply companies. We already outlined the risks of price review and re-opener provisions, which are magnified by the possibility of adverse and possibly mistaken decisions by arbitrators. Declining liquidity in the United Kingdom will increase the risk of inaccurate or manipulated price indices. The thinning statistical base for other fuels used outside the transportation sector will also make indices less reliable.

Integration should also allow Arabian Gulf LNG producers to capture more of the economic rent from the sale of gas. The value of LNG in the European gas markets will depend on its contribution to a broad portfolio of supplies and sources of flexibility, like natural gas storage, and on the variability of European gas demand. The person who controls such a portfolio will retain maximum value from the LNG, but will not have to pay for the full value in a long-term gas sales agreement unless intense competition from other potential buyers in the same market area drives up the price.

There are only a few large gas companies in Europe with the ability to support long-term contracts for LNG, and with some exceptions these companies do not yet compete with each other with sufficient intensity to ensure that the producer of LNG will realise maximum value. Economists have long recognised that integration is a logical response to imperfect competition in specific links of a vertical production and supply chain. We see examples of integration downstream by BG Group (the Brindisi terminal) and Statoil (Cove Point in the United States), as well as upstream integration into the production of LNG by companies like Repsol/Gas Natural, Gaz de France, and Ruhrgas.

The first step in the integration process is to develop a gas sales portfolio that mixes long, medium and short term gas supply contracts with spot sales. As part of this step, a mixture of flexible f.o.b. and c.i.f. or c. & f. sales should be included. This in turn will require the Arabian Gulf LNG producer to control a substantial part of the LNG shipping capacity required to serve all types of trade. The

commercial strategy outlined in this step allows the LNG producer to play the different LNG markets around the world by diverting cargoes to market areas where the best netback value for the LNG can be achieved. Some Arabian Gulf LNG producers already have adopted this commercial strategy.

The second step is to develop an independent gas trading capability. Today independent LNG traders, commercial banks and some of the international oil companies perform this role. When Arabian Gulf LNG producers have an independent gas trading capability at their disposition, they will be able not only to sell but also to buy LNG cargoes to optimise their operation. During periods with a shortage of LNG product, as currently is the situation, an independent gas trading capability is less important than during periods of surplus. However, as outlined above we see the possibility of periods with surplus LNG and falling prices developing in the medium term, particularly in the Atlantic Basin. The probability of such situations will raise the importance for Arabian Gulf LNG producers to protect their projects through hedging operations. Price hedging can of course be obtained directly from third parties such as large commercial banks. However, it is our observation that a good gas trading unit that already optimises LNG producers trading activities also is likely to be in the best position to optimise hedging operations. Trading operations offer synergies for gas producers in the form of market expertise. Over the long run, internal trading operations will cost less than relying on outsiders.

The final step in the commercial risk mitigation strategy is to serve the North West European market from different geographic locations. LNG supplies can shortly be received by terminals in Belgium, France and the UK within the North West European market itself. In the future the possibility of supplying this market area with LNG landed in Italy through the backhaul of pipeline gas will also arise. Furthermore, the gas market in Spain with its extensive and increasing LNG terminal infrastructure is in the future likely to be better connected by pipeline to the gas market in France and therefore the North West European market.

Arabian Gulf LNG producers should therefore in the future have the ability to supply gas to the North West European market through a number of LNG terminals in five or six countries. When this opportunity materialises it is important that Arabian Gulf LNG producers not only deliver LNG into receiving terminals but start building one or more gas supply pools that can serve the North West European market.

Assured access to LNG terminals in different locations would reduce risks. Arabian Gulf LNG producers would not have to rely on spot access to terminals controlled by others, who could use their control during periods of surplus as leverage to pay less than full value for proposed swaps or diverted cargoes. A diversity of terminal sites would also reduce the geographic risks posed by pipeline constraints. For example, relying solely on terminals into the Spanish market would present the risk of a Spanish surplus causing congestion on its limited interconnection capacity to France. Having access to terminals in both Spain and France would mitigate the risk of congested interconnector capacity.

By operating one or more gas supply pools it will be possible to maximise the use of available LNG terminals as well as the shipping elements used to serve these. The optimum method of avoiding bottlenecks in the LNG supply chain might be to buy some gas supplies for the supply pool under medium term contracts from suppliers of pipeline gas as well as covering peak demand periods through spot gas purchases at national balancing points such as the NBP in the UK. By adopting this strategy, Arabian Gulf LNG producers will have moved closer to the end gas consumers in the North West European market. They will also have created gas trading and supply operations that can source gas locally when a gas surplus develops and prices fall while the LNG shipping fleet serves more profitable markets in other parts of the world.

The traditional LNG buyers are becoming more demanding as a result of a pending LNG over-supply position. Their strengthened market position has allowed them to seek additional delivery flexibility. It has also been observed that gas buyers, with increased frequency, now demand an ownership interest in the LNG supply chain used to supplying new contracts, including gas producing fields. By adopting a gas supply strategy based on gas supply pools, Arabian Gulf LNG producers can bypass the traditional LNG buyers. Moving closer to end-consumers and bypassing the traditional LNG

buyers will in turn allow the Arabian Gulf LNG producers to collect an increased portion of the economic rent generated along the LNG chain between the gas producer and the final consumer. The operation of gas supply pools should therefore reduce the risk of an LNG supply project getting into a loss-making position and help secure a bright future for Arabian LNG producers in the North West European gas market.

¹ Expressed in units of standard cubic metres of pipeline quality gas with a gross calorific value of 39 MJ (Sm³).

² *Petroleum Intelligence Weekly*, 17 January 2005 issue.

³ *World Gas Intelligence*, Issue 5 July 2004.

⁴ *World Gas Intelligence*, Issue 19 January 2005.

⁵ DG TREN, *European Energy and Transport – Trends to 2030* (January 2003)

⁶ "Go Ahead Soon for Second Spain-Algeria Gas Pipeline", *European Gas Markets*, issue 14 January 2005, page 11.

⁷ Statement made by Tom Quigley, Managing Director, Mediterranean Gas & Power, BP, during his presentation "The Spanish Gas Market – A New Entrant's Prospective", made to the 19th Autumn European Gas Conference, Barcelona, Spain, 19 November 2004.

⁸ BP indicated that Algerian, Egyptian and Qatari LNG now could be delivered in the form of pipeline gas into the gas transmission system in the UK at a price lower than new Norwegian and Russian pipeline gas supplies (Anne C Quinn, Group BP, presentation to the 19th European Autumn Gas Conference, 8 November 2004, Barcelona, Spain, titled "Adding a Global Dimension to European LNG: Implications and Opportunities").