The 'Shale Gas Revolution': Hype and Reality

A Chatham House Report

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Executive Summary

The hypothesis and why it matters

The recent 'shale gas revolution' in the United States has created huge uncertainties for international gas markets that are likely to inhibit investment in gas – both conventional and unconventional – and in many renewables. If the revolution continues in the US and extends to the rest of the world, energy consumers can anticipate a future dominated by cheap gas. However, if it falters and the current hype about shale gas proves an illusion, the world will face serious gas shortages in the medium term.

The gas context and expectations of future developments

Up to the 1990s, outside the former Soviet Union, gas failed to increase its share in global primary energy consumption. Yet the 1990s saw many of the earlier constraints on its use begin to erode. Together with its natural advantages as an energy source, this opened the prospects of much greater use of gas in the future. At the same time, economic and technical developments in liquefied natural gas (LNG) suggested that the international gas trade was likely to expand. Many observers began to speculate that these developments could encourage gas to become more of an international market. Questions began to be asked about whether the increasing globalization of gas might carry significant consequences, as had been the case with oil in the 1970s and after. However, (largely) unexpected developments in unconventional gas in the US have confused the picture, in what has been dubbed the shale gas revolution.

The shale gas revolution

Since 2000, shale gas production has leapt from accounting for only 1% of US production to 20% in 2009. However, there are doubts as to whether this 'revolution' can spread beyond the United States, or even be maintained within it. The technologies that made this possible – horizontal drilling and hydraulic fracturing – are now coming under increasing scrutiny for their negative environmental impacts: drilling moratoria are being sought while environmental impact studies are completed. Also, although unconventional gas resources are estimated to be five times those of conventional gas, there is concern that their depletion rates are much faster. The US experience was triggered by many favourable factors connected with geology, tax breaks and the existence of a vibrant service industry. There are serious doubts about whether such favourable conditions can be replicated outside the United States, especially in Western Europe where there is much current interest. In Europe the geology is less favourable, there are no tax breaks and the service industry for onshore drilling is far behind that in the United States. Finally, there is concern that disruptions caused by shale gas developments will not find public acceptance, especially in a context where the gas is the property of the state and thus the benefits accrue to governments and not local landowners.

The gas market and investor uncertainty

An immediate consequence of the shale gas revolution has been a reduction in LNG capacity utilization, now reflected in dramatic reductions in forecasts of LNG capacity. In particular, investors in the United States who poured money into LNG regasification plants in anticipation of larger US gas imports have been seriously hurt. Gas prices have been falling, although decreasing gas demand following the global recession has also contributed to this. In many markets these lower prices have raised questions over the traditional link between gas and oil prices. Lower prices have also given rise to speculation over whether major gas-exporting countries may try to protect their interests by collective action through the creation of an Organization of Gas Exporting Countries (OGEC).

Because of the shale gas revolution there are now huge investor uncertainties at all stages of the gas value chain. Whether to invest in gas production – conventional or otherwise? Whether to invest in new pipelines, LNG plant and storage? Whether to 'invest' in long-term supply contracts? All of these uncertainties are likely to lower future investment levels. There are already signs of gas export projects being cancelled or postponed.

The implications

From this uncertainty two major problems arise. First, as the world recovers from global recession and as constraints on gas use continue to erode, demand will grow and gas will probably gain ever greater shares in the global primary energy mix. However, given investor uncertainty, investment in future gas supplies will be lower than would have been required had the shale gas revolution not happened, or at least had it not been so hyped up. If the 'revolution' in the United States continues to flourish and is replicated elsewhere in the world, this inadequate investment matters less. Consumers can look forward to a future floating on unlimited clouds of cheap gas as unconventional gas fills the gaps. However, if it fails to deliver on current expectations – and we will not be sure of this for some time – then in ten years or so gas supplies will face serious constraints. Of course markets will eventually solve the problem as higher prices encourage a revival of investment in conventional gas supplies. Yet given the long lead times on most gas projects, consumers could face high prices for some considerable time.

The second problem concerns investment in renewables for power generation – a necessary consequence of the general agreement that the world must move to a low carbon economy if climate change is to be controlled. The failure of the Copenhagen talks has already injected considerable uncertainty into the investment climate for power generation, not least because of uncertainty over the future price of carbon. The uncertainties created by the shale gas revolution have significantly compounded this investor uncertainty. In a world where there is the serious possibility of cheap, relatively clean gas, who will commit large sums of money to expensive pieces of equipment to lower carbon emissions?

1. Introduction

Before 2007, there was a growing view among some observers of global gas markets that rising demand and the increasing role of liquefied natural gas (LNG)[1] in international gas trade could transform what had been a series of regional markets into a more unified international one. Previously, the so-called 'tyranny of distance' – the high cost of transporting gas, which is a high-volume, low-value commodity – restricted trade to specific regions. In this respect, gas markets resembled the crude-oil markets of the 1950s and 1960s. The expectation that this greater globalization of gas markets would mirror the experience of oil markets after the 1970s gave rise to speculation about how this might alter the associated geopolitics.

However, since 2007 two significant circumstances have thrown views of possible future market developments into disarray. The first was the global economic recession associated with the near-collapse of the financial system that led to a temporary fall in gas demand. The second was the sudden and unexpected development of unconventional gas supplies in the United States, the so-called shale gas revolution.[2] Unconventional gas can be defined as resources that, after the initial well has been drilled, require further processing before it can flow, whereas conventional gas requires no such processing and flows naturally.

Today these two factors have turned the relatively tight gas markets of 2006–07 into a buyers' market. At the same time, many analysts have formed the view that unconventional gas is a major 'game changer' which will have significant implications for the global supply and demand balances, and for how gas markets work together with the underlying geopolitics (Crompton, 2010; Dempsey, 2010; Hulbert, 2010; Jaffe, 2010; Komduur, 2010; Von Kluechtzner, 2010).

This Chatham House Report provides a background and context to recent developments in gas markets and considers how unconventional gas resources might affect them in future. Chapter 2 sets the scene by considering how the differences between gas and oil created a very specific history for gas markets. In particular, it explains why the spread of gas in the global primary energy mix was, until recently, relatively constrained. Chapter 3 assesses the changes that are taking place in gas markets, in particular the erosion of the previous constraints on increasing the use of gas, and the resulting prospect of strong future demand growth. Chapter 4 explains the recent developments in unconventional gas in the United States and the extent to which such developments might be replicated in other areas of the world, especially Europe. Finally, Chapter 5 and the conclusion analyse the potential effect of these developments on the international gas market via their impact on investment.

1 LNG is methane that has been converted to a liquid by lowering its temperature to −161°C. The liquid is then transported in specialized tankers to the market where it is regasified and supplied to the consumer.

2 Since this term has captured the media's imagination, it will be used as shorthand for the many developments in all types of unconventional gas.

2. A Brief History of Gas Markets

Why gas is different from oil

Gas is different from oil. Several differences are key. As suggested in the introduction, gas is essentially a regional rather than a truly global market because of the 'tyranny of distance'. Because it is a high-volume low-value commodity,[3] it is expensive to transport. This means the price differential between different regional markets must be relatively large before it makes commercial sense physically to move supplies between these markets. This also assumes that the infrastructure is in place to move the gas in the first place. The process of physical arbitrage creates a global price across different markets.[4] Without it, as will be seen, there is no such thing as the 'international gas price'. Rather there are a range of regional prices.

This regional dimension of gas markets was strongly reinforced in earlier periods. Early gas consumption was based upon 'town gas' manufactured from coal. Small-scale local companies invariably did the 'manufacturing'.[5] These were monopolies within relatively small areas for markets. Gradually, however, 'town gas' was replaced with natural gas, with 'town gas' production all but ceasing in the US in 1966 and in Europe in the 1980s.

There is less economic rent in the gas price than in that of oil.[6] This is simply because gas delivered to the final consumer has much higher costs per unit of energy and, at least to date, there is no gas cartel to fulfil the same role as OPEC, i.e. restrain supply to ensure significantly higher prices than would exist in a competitive market. Whether the Gas Exporting Countries Forum (GECF) can convert itself into an Organization of Gas Exporting Countries (OGEC) will be considered later in this report.

Security of gas supply is also more complex than for oil. A loss of oil supplies can obviously matter to an economy given the outage costs but once the disruption has been resolved, supplies can easily be resumed. It is also far easier to replace lost oil supplies given the flexibility of oil transport and trade. Gas has much less flexibility in terms of transport and trade.[7] Also safety concerns and the integrity of the gas grid mean it is difficult, expensive and dangerous to turn gas supplies off and on.[8]

Gas trade, unlike oil, requires long-term contracts if trade is to be feasible. The reason lies in the cost structure of gas projects and their specificity. Normally, producing gas and getting it to market requires very large projects characterized by very high fixed costs and relatively low variable costs. This requires that the equipment be operated at full capacity. Less than full capacity operation means that the high fixed costs are spread over a smaller throughput and profits decline exponentially (Mclellan, 1992). Furthermore, because of the economists' 'bygones

3 Crude oil contains an average of 1,010,000 British Thermal Units (BTUs) per cubic feet. Low pressure piped gas contains 180,000 BTUs per cubic feet and natural gas at ambient pressure and temperature contains less than 1,000 BTUs per cubic feet.

4 As will be described below, this is precisely why oil prices are relatively uniform across all regional markets. There exists an international price for crude oil because relatively low transport costs permit physical arbitrage between regions, leading to price equalization.

5 In Europe the municipalities themselves often owned these companies. In the United States they were largely private companies.

6 This statement needs qualifying in so far as gas projects are often based upon the value of the gas liquids that are stripped from the gas and sold separately. In some cases the liquids would justify the development of the gas field even if the gas were then flared. Since, in many cases, flaring is not an option, it represents a negative opportunity cost to the project.

7 This needs qualification since it depends very much upon which area is being considered. Some areas, for example Italy, have access to multiple sources of supply – pipes and LNG. By contrast Ireland is highly dependent upon UK pipeline gas supplies only.

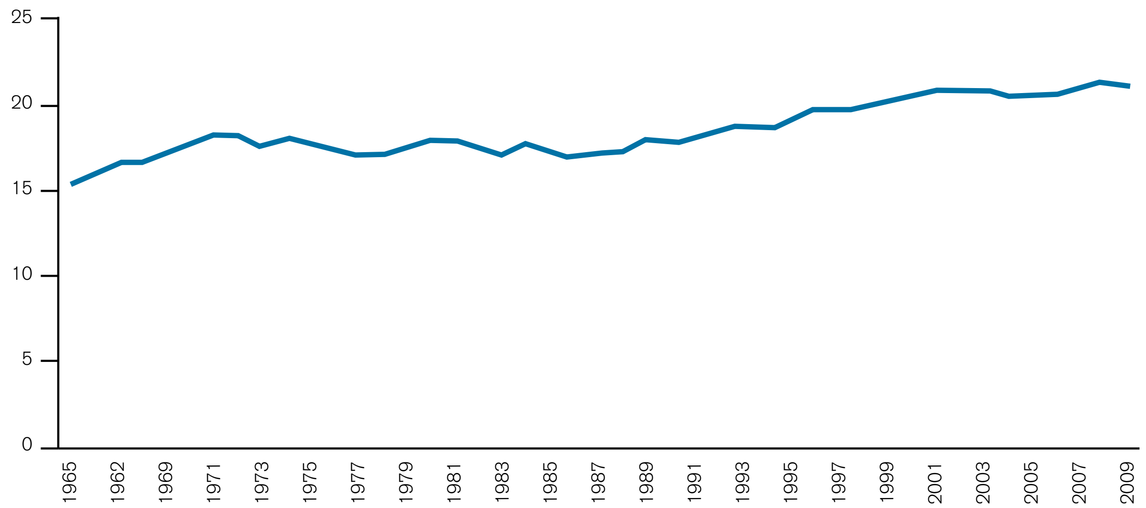
8 In theory, to be absolutely safe, each gas-burning appliance needs to have a gas engineer present before supplies can be reconnected following any outage. In the context of residential supplies this can be extremely time-consuming. In the early 1980s, British Gas – the then state gas monopoly – claimed that if Birmingham, Britain's second largest city, were cut off from supplies it would take around three years to reconnect all customers.

rule',[9] such losses will be borne by the operator for a long time before closure is a rational economic option. Thus any gas project requires a guarantee of supply to ensure full-capacity operation. Long-term contracts are the best option to achieve this unless the gas market is, in economic terms, extremely efficient.[10]

This very high initial cost also needs to lock in future revenue streams by means of long-term contracts to justify the project since the payback period is relatively long. Of course, such cost characteristics are by no means peculiar to gas. For example, upstream oil projects, especially those offshore, are very similar in terms of upfront costs. However, because of the transport constraints facing gas, gas projects are highly specific between buyer and seller. The end of a pipeline is the end of a pipeline. If nothing emerges, finding alternatives supplies of gas is very difficult simply in terms of the logistics let alone in terms of any commercial considerations. In similar vein, LNG sellers must have access to regasification plants and LNG buyers must have access to liquefaction plants. Thus until recently there has been very limited if any flexibility in LNG trade (see below).[11] Here again, as a consequence, gas trade depends upon long-term contracts.[12] This is reinforced because many large gas projects are much more front-end-loaded in terms of capital requirement than even oil deep-water offshore projects and hence need debt financing. Thus long-term contracts are needed to guarantee the servicing of the debt and to help share the commercial risks between the buyer and the seller.

Finally, gas transmission grids are natural monopolies and therefore must either be in public ownership or, if privately owned, heavily regulated. This, together with the need for long-term contracts that tends to inhibit the development of competitive markets, has meant that gas has had much greater state involvement than is the case for oil; indeed, until the 1980s and 1990s, gas companies in

Figure 1: Percentage of gas in global primary energy consumption (excluding former Soviet Union)



Source: BP, 2010

9 This simply explains that, provided the revenue stream covers the variable costs and makes some contribution to fixed costs, losses are minimized if production is allowed to continue. Over time, the fixed costs, which are fixed by virtue of legal contracts, become variable and eventually the loss-making operation will close.

10 For an economist, an 'efficient market' is one with a large number of buyers and sellers together with excellent transparency, not least on prices. The only other alternative to long-term contracts is operational vertical integration where the gas supplies to the project come from an affiliate owned by the company operating the project.

11 For this reason, LNG projects used to be referred to as 'floating pipelines'.

12 FACTS Global Energy in a private communication has pointed out that his requires qualification. Brownfield LNG projects are increasingly signing renewal deals for considerably less than the original 25-year term. However, for greenfield projects long-term contracts will remain the bedrock of the industry going forward.

most markets outside the United States were state-owned utilities.

All the differences outlined above mean the history and trajectory of the gas industry at both national and international levels have been very different from those of oil. Understanding this history provides a valuable context for assessing the actual and potential impact of unconventional gas.

Constraints upon international gas market development in the past

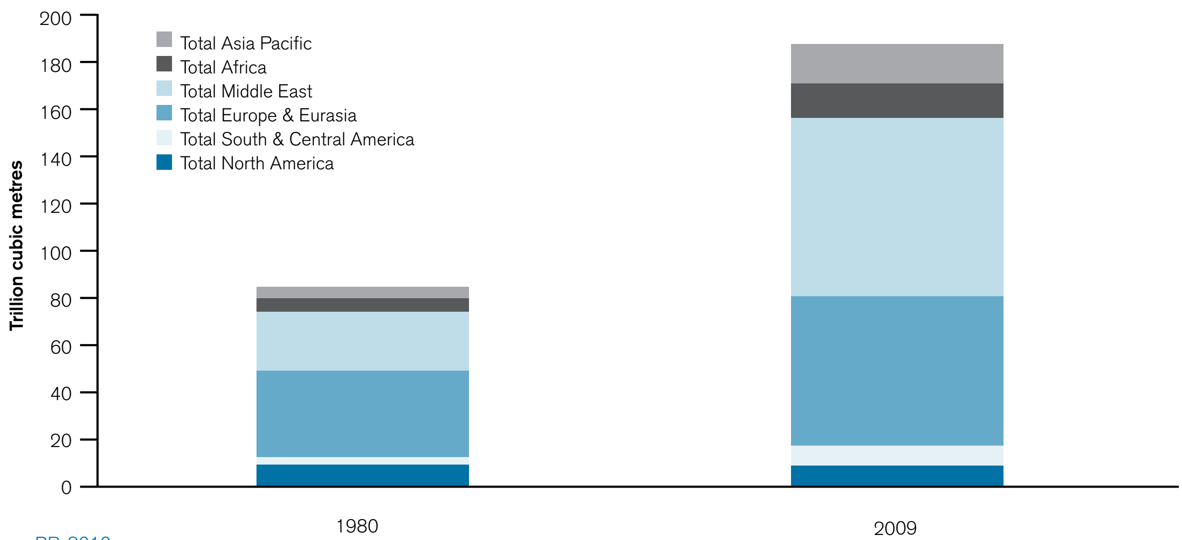
Between 1970 and 1990 gas was a constrained industry. As Figure 1 shows, if the former Soviet Union (FSU) is excluded, gas's market share in the global primary energy mix hardly changed in this period, or indeed since. This is despite the fact that gas reserves have increased considerably since 1980, as can be seen from Figure 2.

This failure to gain market share is more surprising given that gas has many advantages over other hydrocarbons. Once the gas infrastructure is in place, it is extremely easy to handle. It also has very high conversion efficiencies at the burner tip. For example, a standard thermal power station has a conversion efficiency of 33–35%, while that of a modern combined cycle gas turbine (CCGT) station's conversion efficiency is almost double, at around 60%. In terms of environmental concerns, natural gas is relatively clean. It is 30% less carbon-intensive than oil and 50% less than coal. Also emissions of mercury, as well as sulphur and nitrogen oxides (SO_X and NO_X), are negligible compared with those of other hydrocarbon fuels.

Nevertheless, despite such advantages a number of serious constraints up to the 1990s explain the inability of gas to gain market share. These are explored in detail in the Appendix, but can be summed up as follows:

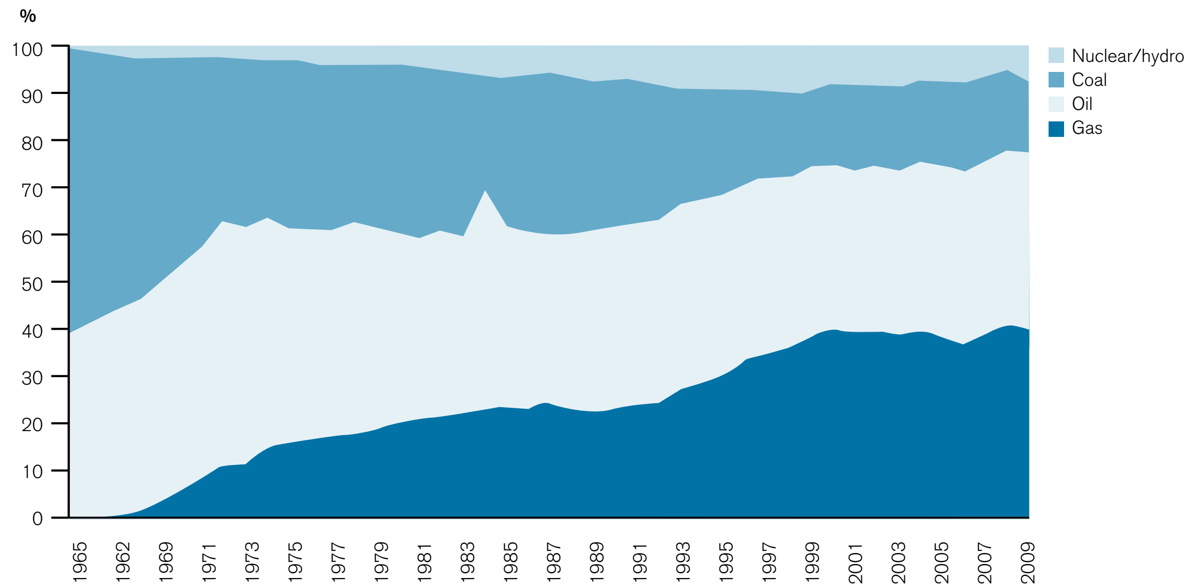
- Gas, relative to the other hydrocarbons, was extremely expensive to transport. There were also problems with transport for exports. Transit gas pipelines suffered in some cases from serious and endemic conflict. LNG also had its problems which until relatively recently were serious enough to constrain LNG projects.
- In the mid-1970s, in both Washington and Brussels, gas was seen as a premium fuel that should not simply be 'burnt'. This led the EU and the United States to introduce legal restrictions on its use in power generation. There were also constraints arising from the policies and politics of gas-consuming countries. Thus, for example, concerns over the security of

Figure 2: World gas reserves by region, 1980 and 2009



Source: BP, 2010

Figure 3: UK primary energy consumption by fuel, 1965-2009



Source: BP, 2010

supply promoted nuclear energy and coal for power generation.

- In most cases, national gas markets were dominated by state-owned utilities operating in a monopoly or monopsony (i.e. with only one buyer for many sellers). By their nature they tended to use this dominant position to act as satisficers rather than profit-maximizers. In many countries the government was a monopsonist buyer of any gas found and often set prices very low to benefit its consumers, thereby inhibiting private companies from exploring or producing.
- The debt crisis meant that developing countries where gas had been discovered could not afford the very large capital expenditure to develop the necessary infrastructure for domestic use.
- In developing countries foreign companies discovered the majority of the gas reserves. Domestic use, say in local power stations, meant the gas would be paid for in local, non-convertible currency, which meant that the shareholders could not be remunerated.
- Export projects need minimum levels of certified, proved reserves to make them viable. Often the reserves found were below this level and the currency convertibility problem inhibited further exploration.
- Negotiating export contracts was complicated because, for example, in the absence of a proper market, as explained in the Appendix, there was no 'gas price' upon which to base the contract price.

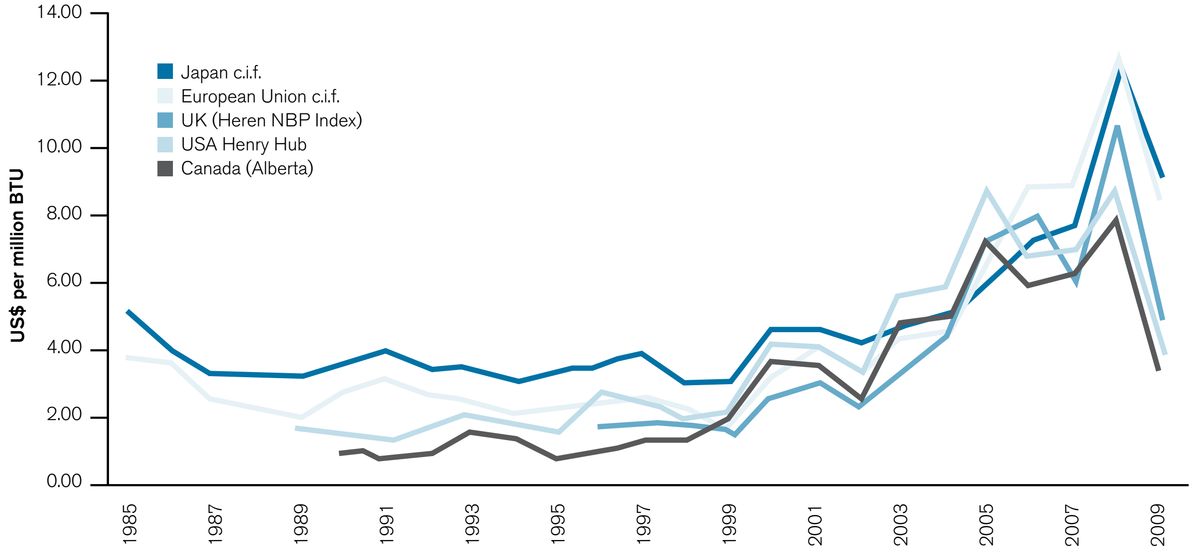
The constraints begin to weaken

During the 1990s many of the constraints inhibiting the use of gas began to erode, as illustrated in Figure 3 in the case of the UK. Again, the Appendix explores this erosion in more detail, but the main factors can be summarized as follows:

- In 1990, both the US and the EU dropped the legal restrictions on the use of gas in power generation.
- Many countries were also trying to reform their gas sectors with the aim of moving them closer to the type of market that would make it much easier to negotiate and manage export contracts.
- The European Energy Charter Treaty (ECT) initially gave some hope that problems over transit pipelines might have some form of collaborative solution.

There have been other more recent developments relating to gas transport that could expand international

Figure 4: Global gas prices 1985-2009



Source: BP, 2010

gas trade. These include compressed natural gas (CNG), gas-to-liquids (GTL), gas by wire and embodied gas.

However, the major changes with respect to transport, and the reason for much of the speculation before 2007 regarding the nature of future international gas markets, are related to improved prospects for LNG projects. Undoubtedly the higher energy density of LNG and its lower maritime transportation costs have made it a key support of the global gas trade. Its greater cost-competitiveness than pipeline gas, its ability to reach markets that were otherwise inaccessible, and its greater flexibility to enhance security of supply, meant LNG could have continued as the world's fastest-growing traded commodity (Aissaoui, 2006). It is doubtful, however, whether LNG, with its very specific handing requirements, could ever match the high fungibility of oil.

Prospects for a global market

Global demand for gas began to rise as earlier constraints were removed and as LNG trade expanded. It became common to find analysts anticipating a move away from regional markets and the development of a more efficient and more international gas market (Rogers, 2010). These views were reinforced when it appeared that regional gas prices were beginning to converge, as shown in Figure 4. This suggested to some observers that the development of arbitrage was beginning and that the establishment of a global gas market might follow. There was growing anticipation that this could presage the sorts of major changes that had emerged from developments in the oil markets after the 1970s (see Box 1).

The benefits of such changes could be considerable. In the words of a recent study on gas markets:

> Extrapolating from the lessons learned from the North American market, an inter-connected delivery system combined with price competition are essential features of a 'liquid' market. This system would include a major expansion of LNG trade with a significant fraction of the cargoes arbitraged on a spot market, similar to today's oil markets. In addition, a functioning integrated market can help overcome disruptions, whether political in origin or caused by natural disasters ... Overall, a global 'liquid' natural gas market is beneficial to U.S. and global economic interests and, at the same time, advances security interests through diversity of supply and resilience to disruption. These factors moderate security concerns about import dependence. (MIT, 2010: 70).

However, after 2007 two events challenged such views of future gas market developments. The first was the global economic recession, which led to a significant slowdown in gas demand. In 2009, global gas consumption fell by 2.1% over 2008 while in the OECD countries the fall was 3.1% (BP, 2010).

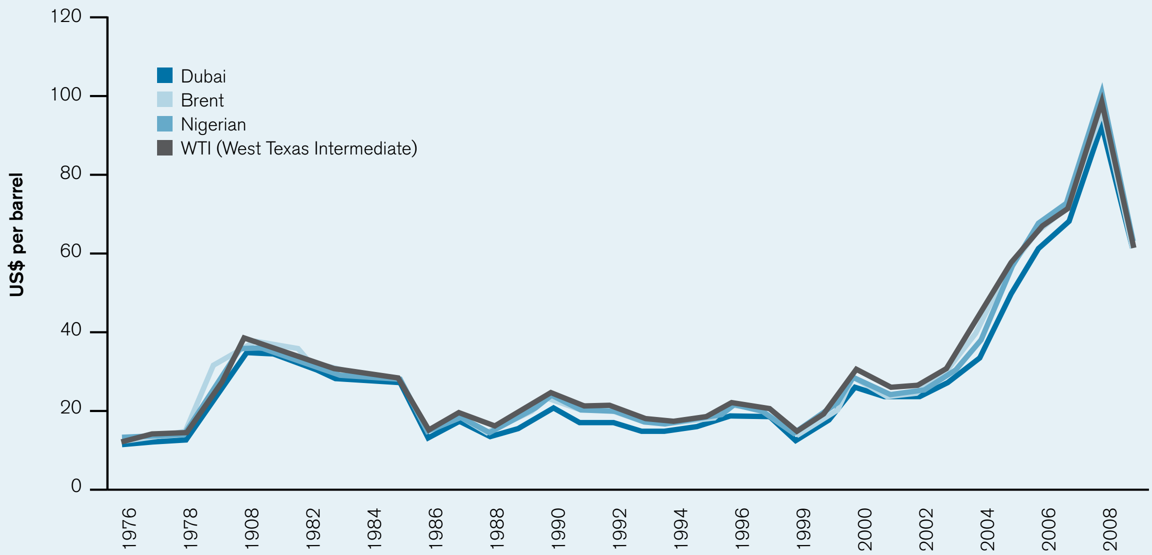
The second event was the generally unexpected emergence of unconventional gas on a huge scale in the United States. This caused US domestic production to rise from 50.7 billion cubic feet per day (bcfd) in 2006 to 57.4 bcfd in 2009 (BP, 2010), and became known as the shale gas revolution.[13]

Box 1: Global markets for oil and gas

The removal of constraints on gas use and the spread of LNG trade began to raise the prospects of a global gas market developing in much the same way that a global oil market developed in the 1970s. To understand the nature of such a development it is worth considering the oil story.

An international market in any commodity is characterized by having a single price rule in different geographic markets.[a] This is created because a price differential between geographic markets, for whatever reasons, will prompt a physical movement of the commodity from the low to the high price market. This process of arbitrage increases the supply in the high-priced market and reduces it in the low-priced market, leading eventually to price equalization. For oil in recent years this can be seen from Figure A. For this to work in any commodity a number of conditions must be met. First, there has to be freedom of movement for the commodity so that it can physically move between geographic regions. Second, there has to be good information so that owners of the commodity are aware of the emergence of price differentials. Third, the transport cost must be sufficiently low to allow small price differentials to make physical movement worthwhile. Finally, there has to be some means to lock in an existing price differential if it takes a significant amount of time to physically move the commodity, so that when it arrives in the higher-priced markets the price differential is still in existence. If these conditions exist, then the global market for the commodity can be seen to be an 'efficient' market in the sense used by economists.

Figure A: International oil prices, 1976–2009



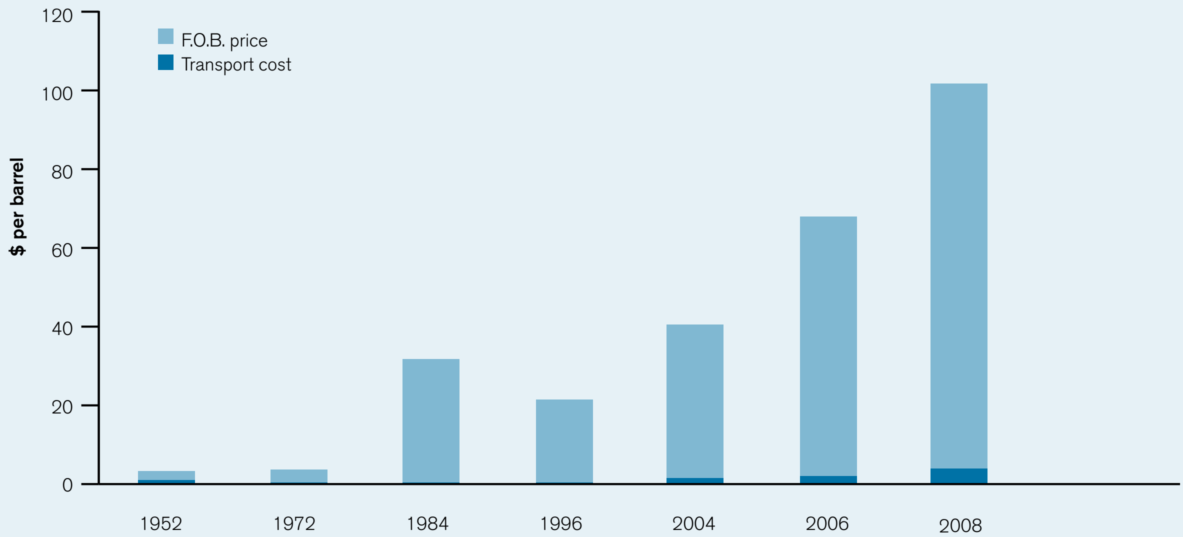
Source: BP, 2010

13 It is argued by FACTS Global Energy (private communication) that even without these two developments a global gas market would still have been some way off. This is because of the lack of Asian gas market transparency. But even more important is the inability of LNG buyers and sellers to agree upon an alternative pricing mechanism. Until this happens, they argue there will be no global price benchmark, which is a vital ingredient of an integrated market.

In the 1950s and 1960s such conditions were not present in the world's crude oil markets. Transparency on prices was extremely poor and it was extremely difficult to identify price differences.[b] However, the key to the absence of a global market was that, as can be seen from Figure B, the transport element of the landed cost of crude oil was relatively high. On the basis of computations by the author, in 1952 the c.i.f. element of the landed costs of crude oil in New York Harbour loaded in Ras Tanura in Saudi Arabia was some 55% of the landed price. Even by 1972, it was still as high as 31%. Thus very high regional price differences were required before the arbitrage process could operate. Crude oil was essentially a series of regional markets. This was reinforced in 1959 when the US effectively isolated itself from international markets by severely restricting crude imports.

However, in the late 1960s transport costs were reduced by the development of the very large crude carriers (VLCCs) with their large economies of scale. This was reinforced by the collapse in tanker rates as a result of declining oil demand after the first oil shock of 1973–74 in the context of a surge in new tanker capacity coming off the slipways.[c] Together with much higher oil prices following the oil price shocks of the 1970s, the proportion of landed prices accounted for by transport costs fell dramatically, as can be seen in Figure B.

Figure B: The landed cost of crude oil from Ras Tanura to New York



Source: Estimated by the author

After 1973, the proportion of landed costs taken by transport from Ras Tanura to New York never exceeded 4%. Thus relatively small price differentials between regions could trigger the physical movement of oil, leading to an internationalization of oil markets after the 1970s. This was reinforced because the rise of paper markets for oil such as NYMEX in New York and the IPE in London (later the ICE) not only improved the information flows between markets, they also allowed crude owners to lock in the price differentials as they appeared, to await physical delivery. That the oil market became more international can be seen clearly from Figure A which shows prices in different regions moving together, as would be expected in an efficient market with relatively low transport costs.

The development of this efficient international market for crude oil had many significant consequences. It meant that the IOCs began to move away from the use of operational integration and instead use the increasingly efficient oil markets.[d] One consequence of this was the serious decline of long-term contracts for trading in oil and the rise of spot trade.[e] This in turn began to raise issues to do with security of oil supply and the consequent geopolitical dimensions of oil markets. Oil price volatility also increased significantly. Overall, the changes to international oil markets that began in the 1970s were to have major consequences.

a For crude oil this is complicated by the fact that crude is not a homogeneous product but is differentiated by a number of quality differences such as specific gravity (measured in degrees API), sulphur content and other chemical characteristics.

b This was because the major oil companies used operational vertical integration. Thus their crude producing affiliates supplied their refineries based upon inter-affiliate transactions as posted prices.

c This reflected the view at the start of the 1970s that world oil demand would grow at the very high levels seen in the late 1960s and early 1970s, which led to an investment boom in transportation and refining.

d Financial vertical integration is when the same company owns affiliates in the different stages in the value chain – for example, production, refining and marketing. Operational vertical integration is when there is physical movement of crude and products between the owned affiliates on an inter-affiliate basis as opposed to arm's length transactions in the open market.

e 'Spot trade' refers to a single one-off transaction to buy a specific stock of oil or gas. A 'term trade' is where a flow of oil and gas is sold over time.

3. Unconventional Gas

The technical background

There are a number of different sources for unconventional gas.

- *Gas hydrates*: These are gas deposits trapped in ice crystals in permafrost and on the ocean floor. 'The gas resource contained in hydrates is estimated to be larger than all other sources of natural gas combined, but most such gas is not commercially producible with today's technologies' (IEA, 2009: 411).
- *Coal-bed methane* (CBM): Also known as coal seam gas, this is simply natural gas contained in coal beds. Normally the coal beds are regarded as commercially sub-optimal. The International Energy Agency (IEA, 2009) estimated CBM to be the source of 10% of total gas production in the United States in 2008, 4% in Canada and 8% in Australia. China and India, with their huge coal reserves, also have great interest in developing their CBM capability. In China, CBM has been made one of the 16 priority projects in the 11th Five-Year Plan.
- *Shallow biogenic gas*: This is gas found in coal seams generated by biogenic processes rather than the thermal maturation that produces CBM. At present it is mainly found in Western Canada.
- *Tight gas*: This refers to gas deposits found in low-permeability rock formations that require fracturing to release them for production. The IEA suggests a definition that is based upon a gas reservoir that cannot be developed commercially by vertical drilling because of the lack of natural flow (IEA, 2009). Also, even with horizontal drilling, hydraulic fracturing[14] is required to produce commercial quantities.
- *Shale gas*: These are deposits trapped within shale rocks. Unusually, these rocks are both the source of the gas and the means of storing it. They also tend to overlie conventional oil and gas reservoirs. Thus if there has been extensive exploration for conventional oil and gas the existing well-cores can generate large amounts of data to locate the potential shale plays.[15]

It is the last two categories, shale and tight gas, that are currently generating the most media interest.[16] Such deposits have characteristics that are important for their profitability and future prospects. Compared with conventional gas reserves,[17] shale and tight gas are spread over much wider areas. For example, shale gas deposits in place are around 0.2 to 3.2 billion cubic metres (bcm) per km² of territory, compared with 2–5 bcm per km² for conventional gas (IEA, 2009). Thus shale and tight gas require many more wells to be drilled.[18] Furthermore, the wells deplete much faster than conventional gas wells and their depletion profile is an early peak followed by a rapid

14 Hydraulic fracturing is the high-pressure injection of water, chemicals and sand to break up the rock structure and allow the gas (or oil) to flow more easily.

15 Shale gas resources are called 'plays' rather than fields, reflecting the fact that they generally cover very large geographic areas. In the US, the main plays are the Barnett play in Texas (the largest), Eagle Ford in Texas, Haynesville straddling Texas and Louisiana, Fayetteville in Arkansas and Oklahoma and Marcellus (probably the most promising) in the Appalachians.

16 CBM is also important and CBM LNG projects are planned for Australia and Indonesia, while the long-term potential for China and India is important given their coal reserves.

17 Conventional gas reserves are either those of associated gas produced as a by-product of crude oil production, or those of non-associated fields. These produce methane which is dry natural gas, although often methane is produced as part of wet gas. This includes various liquids such as condensates/ natural gas liquids which must be stripped out before the gas can be used as gas.

18 However, one benefit of this characteristic is that the risk of drilling a dry well is very much lower than in a conventional gas basin. Also, as indicated, many potential shale formations overlie developed conventional gas reserves, which means core samples are available from already drilled wells to make appraisal easier.

decline.[19] Experience on the Barnett Shale Play shows wells depleting by 39% in years one and two; 50% between years one and three; and 95% between years one and ten. Thus shale wells might have a life of 8–12 years, compared with 30–40 years for a conventional gas well. Even this may be overstated; one source has claimed that on the Barnett Shale Play, 15% of wells drilled in 2003 were exhausted within five years (Ivanov, 2010). It should also be emphasized that the ultimate recovery on a shale gas well is much lower (8–30%) than for a conventional well (60–80%) (Vysotsky, 2010). Thus far more wells are required than in a conventional gas field. One source claims that on the Barnett Play in north Texas the average wellhead density is 12 per km².[20] However, the technology for shale continues to evolve. Energy Policy Research Incorporated (EPRINC) reports evidence that producers have become increasingly successful in managing decline rates over the past few years and that they appear to have become better at softening the impact of decline rates as the hydraulic fracturing technology develops.[21]

To release the shale or tight gas requires hydraulic fracturing using chemicals[22] and sand to maintain the increased porosity once the rock structure has been fragmented.[23] Hydraulic fracturing was first used in the United States in 1947 and entered commercial use after 1949.[24] By the early 1980s there were 710,000 wells producing some 3–4 bcm/y from the Antrim Shale Play in the Midwest. However, shale gas really began to take off following the application of new technologies, notably horizontal drilling and hydraulic fracturing, in the Barnett Shale Play this century. In 2008, shale gas produced some 50 bcm and its share of total proven gas reserves increased by 50% to more than 600 bcm at the start of 2008 (IEA, 2009). However such techniques require a great deal of fluid to be injected,[25] and the resulting saline water that is forced to the surface then has to be managed. There is also concern that the chemicals used may well contaminate local water sources. This could present a major barrier to the development of shale and tight gas in the future (see below).

Shale and tight gas also require the extensive use of horizontal drilling to maximize the surface contact with the gas deposits.[26] Of particular importance in this context is the development of coil tube drilling.[27] It has been estimated that globally there are 1,700 of these drilling units, of which more than half are in North America. This is a new technology that is pushing the limits but is growing bigger and developing niche applications (Mazerov, 2010).

All of these characteristics should have made shale gas more expensive to produce, reducing profitability at the well. However, there are widely divergent cost estimates for shale gas, a problem compounded by the geological differences between the plays and between wells within the same play. Various estimates collected on the Gazprom website range from \$100–150 per tcm to \$144–88 per tcm, compared with \$20–42 per tcm for West Siberian conventional gas. However, it must be pointed out that shale gas presents a very serious challenge to Gazprom's profitability and the company may have a vested interest

19 This is actually a controversial issue, not least because there is not enough experience to determine the ultimate shape of the decline curve. According to Jensen (private communication), most independents are booking reserves on the assumption that the well will last for fifty years – albeit at very low producing rates.

20 Komduur (2010). To put this in perspective, in 2008 Saudi Arabia, with a surface area of 2,218,000 km², had 2,811 producing wells; Venezuela, with 916,000 km², had 14,651 wells; and the Barnett Play, with 13,000 km², had 8,960 wells.

21 Private communication from EPRINC.

22 The actual chemicals tend to be matters of commercial secrecy; hence the FRAC Act in the US (see below), but a commonly used one is granulated aluminum silicate.

23 This makes shale gas very energy-intensive to produce. However, the author is unaware of any study examining its energy life-cycle. In the case of shale oil, it is well established that more energy is put in than comes out! The logic is that the energy input has a lower market value than the energy output. A study by Robert Howarth of Cornell University (quoted in Kefferputz, 2010) argues that greenhouse gas emissions from shale gas from hydraulic fracturing are similar to those from coal from mountain top removal. However, Dr Howarth clearly states his estimates are 'highly uncertain'.

24 The first shale gas wells began producing in the US in the late 1820s (IEA, 2009).

25 Shale plays tend to require more equipment, larger volumes of water and chemicals, and higher pressure than tight gas deposits (IEA, 2009).

26 In horizontal drilling the drill cuts down vertically for up to 7,000 metres and then continues horizontally for up to 2,000 metres (Kefferputz, 2010).

27 The well is drilled by flexible pipe using liquid nitrogen and can be used in an existing well while it is still producing. The units can be moved easily. This is in contrast to conventional drilling rigs that require very large derricks, large quantities of drilling pipe that are then screwed together, and the handling of very large volumes of drilling mud.

in downplaying the prospects. Also the figures quoted are the wellhead costs (the so-called 'prime cost'), which take no account of the cost of transporting the gas to market. By contrast, the IEA estimates that the cost of Barnett Shale gas is $3 million British thermal units (BTUs) and can be optimized to $2.50 (IEA, 2009). In the United States, it appears most observers currently expect shale gas economics to be superior to those for conventional gas.[28] The rapid development of shale in the United States can also be attributed to the easy and low-cost access to the gas transport network (see below).

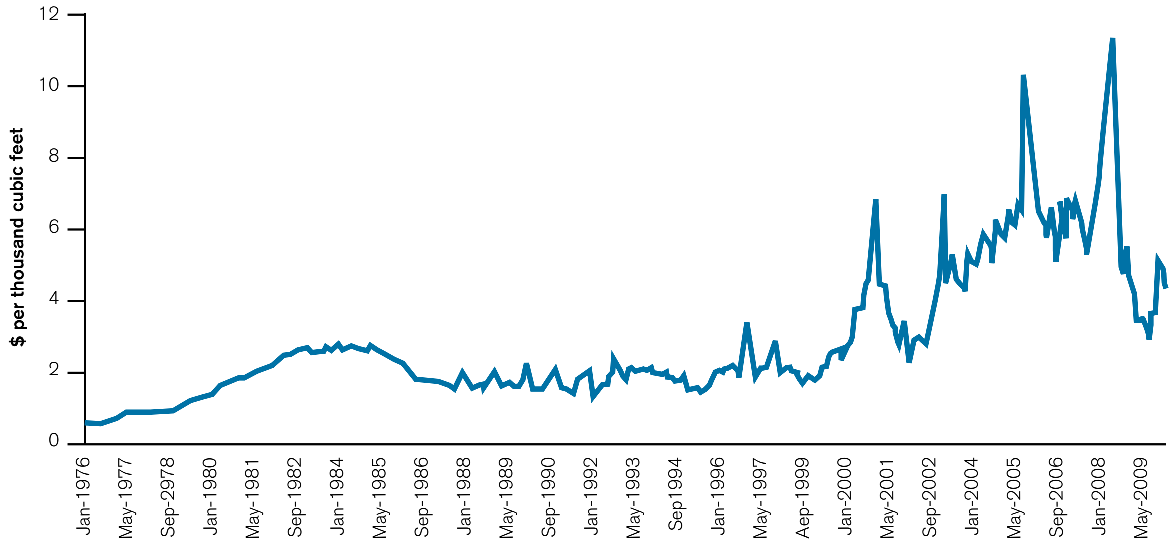
Finally, the geology of the various unconventional gas plays varies enormously. This is relevant in the context of 'learning by doing'. With the application of any new technology there is a learning curve. In general, the further down the learning curve the operator advances, the lower the cost of production. However, if the plays differ enormously then there will be a very limited aggregate learning curve effect. If each play is different, lower costs based upon operating experience may only be applicable to that play and not more generally. Despite this, some claim that producers of shale oil seem capable of benefiting very quickly from 'learning by doing' as operations proceed. For example, substantial productivity gains have been registered with operators able to increase well output by up to ten times in the trial stages of the first dozen or so wells in geologically similar areas (IEA, 2009).

These technical characteristics give rise to two key questions about the shale gas revolution in the United States: will it continue or fizzle out; and will it be replicated elsewhere? It is the answers to these questions that generate the enormous uncertainty that is engulfing the global gas market.

Developments in the United States

It is in the United States that unconventional gas has really taken off in recent years and technological developments have made a major contribution to developing the resource. Shale gas has been produced in the United States for over 100 years in the Appalachian and Illinois Basins.

Figure 5: US domestic gas prices



Source: US Department of Energy

28 This is based upon a private communication with Jim Jensen. He suggests that we could see shale gas setting such a low price that conventional drilling suffers significantly. Measures of wells drilled per rig, length of the horizontal run and hydraulic fracturing zones per well are changing dramatically, as is productivity. The claim of unconventional gas being cheaper than conventional gas is also repeated by Cambridge Energy Research Associates (CERA) (quoted in Kefferputz, 2010).

However, in recent years a number of factors have come together to create a major push to develop the resource.

First, there now exists a great deal of geological knowledge. In many cases unconventional reservoirs overlie conventional deposits, many of which have been extensively explored. This provides a good starting point for knowing where to drill, based on the earlier well cores that passed through the unconventional plays. Often conventional wells explore below the initial find and this can also provide data on shale plays below conventional deposits. Over the last 150 years, the United States has had considerable experience of drilling for oil and gas. This gives a head start when investigating possible shale deposits.

Secondly, in 1980, the Crude Oil Windfall Profit Tax Act introduced an alternative (non-conventional) fuel production tax credit of $3 per BTU oil barrel – 53 cents per thousand cubic feet (tcf) – under the Section 29 Credits of the Act. This credit, which remained in force until 2002, was a function of the price of oil. To reduce the incentive to switch from unconventional gas to oil products when oil prices fell, a decline in oil price was matched by an increase in the tax credit. Given that after 1980, as can be seen from Figure 5, the wellhead price rarely exceeded $2 tcf, this was a significant incentive to attempt to develop unconventional gas. After 2000 prices (and hence profitability) began to rise, further encouraging gas production.

However, the development of unconventional gas was inhibited by the lack of suitable technology. The technological developments, in particular with horizontal drilling and hydraulic fracturing, were a third major factor in the American story. For example, in 2004, 490 of the 920 wells in the Barnett Play were vertical. By 2008, as many as 2,600 of the 2,710 wells were horizontal (IEA, 2009).

An issue that has come to the fore concerns the potential for contamination of ground water as a result of the chemicals used in hydraulic fracturing. So far unconventional gas operations in the United States have been remarkably free of restrictive regulations at federal or state levels. In large part this is because the techniques are so different from conventional operations that they are simply not part of the existing regulations,[29] or, in some cases, exclusions could be slipped in by the legislators without attracting much attention. For example, the Energy Policy Act of 2005 exempted hydraulic fracturing from the Safe Drinking Water Act.[30]

However, there are signs that this is beginning to change. If Congress passes the Fracturing Responsibility and Awareness Chemicals (FRAC) Act introduced in 2009, the Environmental Protection Administration (EPA) would be permitted to regulate all hydraulic fracturing in the United States. In May 2010, the Pennsylvania state legislature passed the Marcellus Shale Bill that enforced a three-year moratorium on further leasing of exploration acreage until a comprehensive environmental impact assessment has been carried out. In March 2010, the EPA announced a study to investigate the potential adverse impact of hydraulic fracturing on water quality and public health.[31] Interestingly, ExxonMobil included a provision in its acquisition of XTO Energy (see below) allowing it to pull out of the agreement if Congress makes 'hydraulic fracturing or similar processes … illegal or commercially impractical' (Kefferputz, 2010).

Despite these concerns it should be borne in mind that oil and gas operations are commonplace in the United States and widely seen as 'normal' by local populations. The nature of subsoil property rights in the United States is in fact a fourth important factor assisting the development of unconventional gas there. Because the subsoil hydrocarbons are the property of the landowner, much of the very large areas leased for exploration for unconventional gas was privately owned. Thus those near to the operations and potentially suffering disruption were also directly benefiting. The prospect of revenue from gas sales acted as a strong incentive to accept a degree of local disruption.

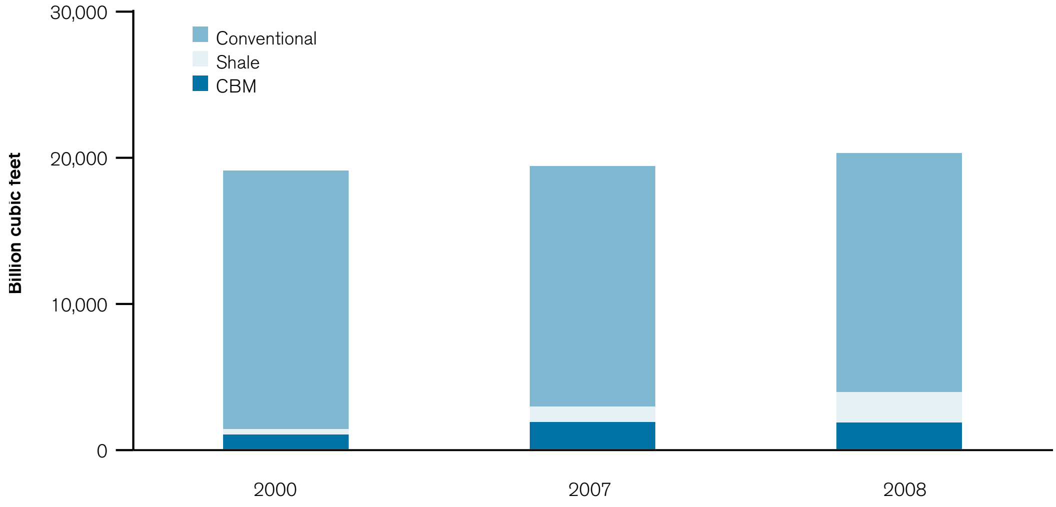
A fifth factor was the existence of a dynamic and competitive service industry able to respond to the interests of the operators. Until recently, independent US oil and gas

29 In Western Europe the various national laws and regulations governing oil and gas production do not even mention unconventional gas (see below).

30 This is often called the 'Halliburton loophole' in (dubious) honour of Vice President Dick Cheney (Kefferputz, 2010).

31 There has also been local concern over a problem on the Marcellus play when in June 2010 large quantities of gas and toxic chemicals were released from a well in Clearfield County, although this was caused by blowouts rather than hydraulic fracturing.

Figure 6: Source of domestic US gas supplies



Source: US Energy Information Administration, http://www.eia.gov/

companies, together with the oilfield service companies, undertook most of the development of unconventional gas. However, the larger international oil companies (IOCs) have recently begun to take a serious interest in this area. In 2009, ExxonMobil paid $41 billion to buy XTO Energy, the third largest gas producer (mainly of unconventional gas) in the United States. In 2009, Statoil paid $3.4 billion for 32.5% of Chesapeake Energy, another important player in unconventional gas. In 2010 Shell announced that it is paying $4.7 billion for East Resources, which operates in the Marcellus Play in the northeastern United States. It is likely that the interest of foreign companies is driven by a desire to gain experience that can be transferred to their home territory. This would certainly seem to explain the motive for the recent purchase by Reliance of India of shares in Atlas Energy and Pioneer, both of which have interests in the Marcellus and Eagle Ford shale plays.

The first serious commercial flows began in 1981; by the late 1990s the Barnett Play was producing 13 bcm. In 2002, the first horizontal well was drilled on this play and by 2009 it was producing 76 bcm, over 11% of total US gas production. The technology has been developing quickly. It took the Barnett Play 20 years to achieve 5 bcm while the Fayetteville Play reached this level in four years (IEA, 2009). One consequence is that estimates of shale gas resources have risen dramatically. In April 2009, the US Department of Energy estimated the Marcellus Shale Play to have 262 tcf of recoverable reserves and the Energy Information Administration suggests that technologically recoverable gas reserves are 1744 tcf. According to one estimate from CERA, shale provided 20% of US gas supply in 2009, compared with only 1% in 2000, and this is expected to rise to 50% by 2035 (quoted in Kefferputz, 2010).[32] However, it is important to repeat the point made earlier about the characteristics of shale gas fields: because of the enormous geological differences, not just between plays but between wells in the same play, extrapolation from one play or well to another needs to be treated with extreme care. There is no clear aggregate 'learning by doing' curve.[33] Nonetheless, the recent impact of shale on US domestic gas supplies can be seen from Figure 6.

32 The US EIA data claim shale production accounted for 11.45% of US production in 2009 and 2.2% in 2000. Unfortunately, statistics associated with the shale gas revolution are extremely uncertain. One is reminded of the old adage that the definition of a fact is anything which appears on the internet, and it also a well-known fact that 83.42% of all statistics are made up on the spot!

33 A counter-view to this is that one reason for the US boom is that knowledge of operating in shale plays developed quickly and was widely disseminated. Furthermore it is the knowledge gained by the relatively small companies that explains their acquisition by the larger companies, which hope to export it abroad. Certainly it has been suggested to the author that this is the main reason for Reliant of India's acquisition of US interests.

One study suggests that the current mean estimate of recoverable shale reserves is 650 tcf within a range from 420 to 870 tcf (MIT, 2010).[34] Furthermore, of the mean estimate, 400 tcf is commercially accessible at wellhead prices of $6 per million BTU.

Prospects outside the United States

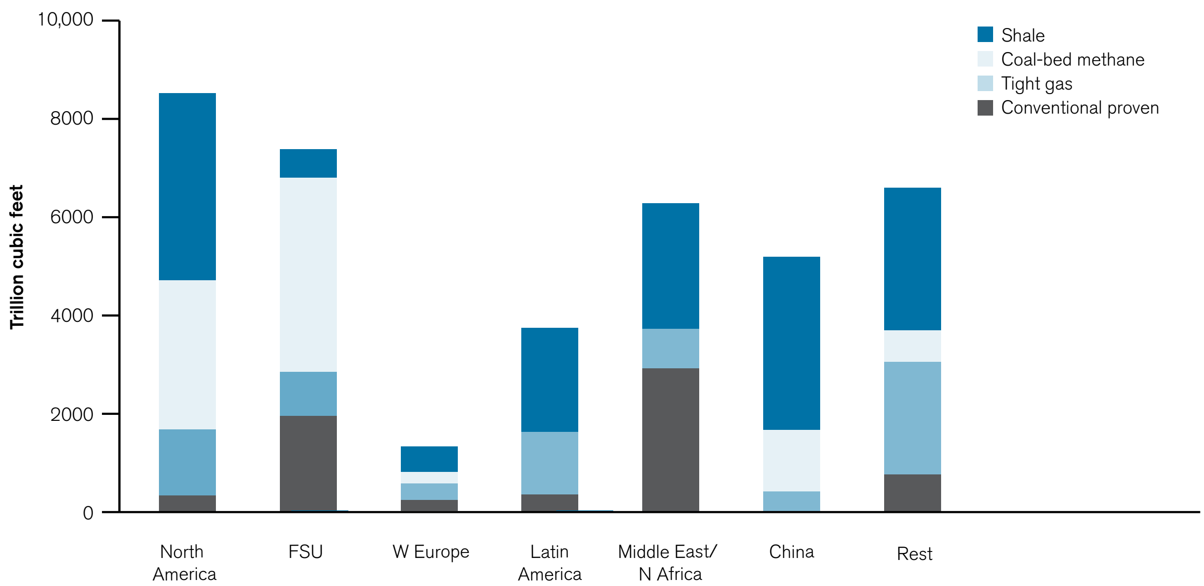
The US shale gas revolution has triggered a debate over how far it might be replicated outside the United States. As can be seen from Figure 7, it is estimated that there could be very significant global reservoirs of unconventional gas. If these could be converted into produced natural gas, this would be a major 'game changer' for world energy.

In Western Europe, the prime targets (based upon geology) are Poland, Germany, Hungary, Romania, Turkey and the northwest of England. In particular, ExxonMobil, Conoco-Phillips and Chevron have all signed or are negotiating exploration agreements for shale in the Lublin and Podlasie Basins in southeast Poland.[35] In 2009, the industry and the German National Laboratory for Geosciences launched a research programme for gas shale in Europe (GASH) that aims to assess the volumes in place and the ability to produce them profitably in Western Europe.

In Latin America much attention is being directed to Argentina and Chile. China and India have expressed strong interest in CBM given their extensive coal deposits,[36] and China also appears interested in the potential of developing shale gas. In Canada, the National Energy Board believes there is potentially at least 1,000 tcf of shale gas to be found.

However, there are many barriers and constraints to be overcome if the potential is to be converted into energy at the burner tip. The IEA lists six conditions if unconventional gas is to develop (IEA, 2009). Given that much of the interest outside the United States is focusing on Europe, it is worth considering how each condition might apply in a European context, especially in relation to the US experience.

Figure 7: Estimates of global gas resources



Sources: The conventional proven gas reserves are for 2007 and have been taken from BP, 2008. That date has been chosen on the grounds that the estimates for North America at that time would not include much by way of unconventional resources. The other data are taken from NPC, 2007.

34 To put this into perspective, according to BP (2010) proven gas reserves in the US in 2009 were 245 tcf.

35 Dempsey (2010). Currently in Poland there are 40 exploration licences awarded (Kefferputz, 2010).

36 China has made CBM one of the top 16 projects in the 11th Five Year Plan, which set a target of 10 bcm by 2010, compared with 1.8 bcm in 2008 (IEA, 2009).

1. Easy identification of the location and potential of the best plays

A major potential problem in Europe is that the geology for shale gas is much less promising than in the United States. In general the deposits are deeper, the materiality in terms of gas deposits lower and the basins smaller. The plays are more fragmented and the shale is richer in clay, making these deposits less amenable to fracturing. In short, they do not hold out the same promise as deposits in North America, which are large and often shallow. Furthermore, they lack the history of drill core evidence that exists in the United States, since onshore drilling in Western Europe has been much more limited.

2. Rapid leasing at low cost of large areas for exploration and development

This presents a serious problem in densely populated Western Europe. The population density in the United States is 27 per km²; in England (which is at the higher end of the range for Western Europe) it is 383. Traditionally, exploration licences onshore in Western Europe have been granted over relatively small licensing areas, each with its own specific work programme as part of the contract. This would require the granting of a lot of small areas to make the plays economically viable. The laws and regulations covering oil and gas exploration and development in Western Europe do not even make reference to unconventional gas, which means that the existing legal framework is not geared up to its management. A good example of the problems this might create is presented by the technical definition of a 'gas field'. Normally a gas field is defined territorially in terms of the gas/water contact. In the case of an unconventional gas field there is no such contact point and therefore no definable 'field' under the current legislation. However, by contrast the environmental legislation, especially at a local level, is much tougher and more specific than in the United States – at least up until now – and so would present serious challenges for unconventional gas operations in the context of hydraulic fracturing. Large areas of leasing would also provoke considerable local opposition, an issue developed below.

3. Experimentation and adaptation of drilling and completion technologies

The US experience was dependent upon the existence of a competitive and dynamic onshore service industry. Currently, there is no comparable onshore service industry in Europe and the scale of requirement is enormous. One estimate is that for Western Europe to produce one tcf of shale gas over 10 years (around 5% of total gas consumption in Western Europe) would require around 800 wells per year to be drilled (IEA, 2009). At the peak of the recent boom in the Barnett Shale Play in 2008, 199 rigs were in action (Star Telegram, 2010). However, as of April 2010 there appeared to be only around 100 land rigs in Western Europe, compared with some 2,515 active rigs in the United States in 2008, of which 379 were in oil and 1,491 in gas.[37] Putting it simply, the infrastructure in Europe does not currently exist to mount enough unconventional gas projects to make a difference. This can change if the projects appear profitable, but it will take time.[38] Also for the reasons outlined above and below, costs in Western Europe are likely to be high and margins tight. Currently, only Hungary has any tax incentives for unconventional gas,[39] which means the profitability spur to develop a service capability is likely to be muted. Furthermore, since much of the technology for horizontal drilling and hydraulic fracturing is under American control, this could cause friction if local employment and value chain development were seen to be frustrated by imported American technology.

4. Acceptance by local communities

For Western Europe, this condition is likely to present the major challenge to the development of unconventional gas.

37 It has been suggested to the author that many of the existing shale exploration contracts in Europe are unlikely to meet their basic contracted work programme because of a serious shortage of rigs.

38 However, competition for drilling rigs is also likely to be acute over the next ten years. For example, a major constraint on the implementation of the recently signed upstream oil contracts in Iraq is a serious shortage of land rigs available in the region. Given the potentially higher profits in oil, rigs are more likely to move to oil than gas.

39 Bear in mind the crucial role played by tax credits on unconventional gas in the United States.

Large-scale disruptions caused by drilling and hydraulic fracturing are likely to generate huge local opposition, especially given concerns over environmental damage. While some operations are beginning to face increased local opposition in the United States, there is a financial incentive for local communities to suffer the inconveniences because the resource is the property of the private landowner and not the state. In Europe, by contrast, the state will reap the financial rewards of the resource and provide no financial incentive for the local community.[40] This is likely to be exacerbated by the fact that, unlike the United States with its 'mambaland'[41] characteristics, Europe is densely populated and highly urbanized. Large-scale unconventional gas operations will impinge on local communities and they are certain to pursue a path of local opposition, or 'nimbyism.'[42]

5. Resolution of the environmental consequences, especially over managing water

This condition is complicated because the implications of hydraulic fracturing for water tables and water management are not well understood. The industry position in the United States has been to argue that the problems are being overstated and that the industry can be trusted to manage the issues in a responsible manner. In the aftermath of the recent Macondo spill in the Gulf of Mexico, such arguments appear thin.[43] It should also be noted that, since the subject is only now being examined in any detail, it is not at all clear that current investigations will give industry a clean bill of health. Further environmental concerns also remain, including the possibility that hydraulic fracturing might release naturally occurring radioactivity. This prospect has thus far received little publicity but could provoke a highly emotive debate.

6. Adequate local infrastructure to transport and manage equipment and water

The problem of the lack of drilling rigs has already been mentioned. Yet a larger concern is that shale gas requires large quantities of water to be managed: it has been estimated that 4–5 million gallons are needed to fracture one well (IEA, 2009).[44] A further issue is the relative ease of non-discriminatory access for US gas producers to the very extensive liberalized gas grid and trading hubs. In Continental Europe, owing to a market structure dominated by few players, such access is much more complicated, despite the best efforts of the European Commission.

On balance, therefore, it is likely to be some time before it will become clear whether or not the shale gas revolution might sweep Europe. The list of constraints is formidable. However, such difficulties are doing little at the moment to dampen some of the hype generated by the potential for a repeat of the US experience in Europe (Jaffe, 2010).[45] The discussion of shale gas in Europe has tended to attract what might politely be called 'spectacular statistics'. For example, the IEA claims (admittedly with many caveats) that the shale resources in the European OECD member states, if they followed the same development trajectory as in the United States, could replace 40 years of current gas import levels (IEA, 2009).

Globally, the picture is even more uncertain in terms of the possible development of unconventional gas supplies and the replication of the US experience. The IEA sees unconventional gas, which accounted for 12% of global gas production in 2007, rising to 15% by 2030 – although the majority of this increase is expected in North America (IEA, 2009). There has clearly been a great deal of interest in non-conventional gas in China. Initially this was focused on CBM, and FACTS Global Energy estimates

40 In New York State, for example, some residents are offered up to $5,500 per acre with 20% royalties on any gas produced (Kefferputz, 2010).

41 'Mambaland' was an acronym invented by the British military fighting in Mesopotamia in the First World War, and simply stands for 'mile and miles of bugger all'. It was revived by RAF pilots in the last Gulf War to the bemusement of American air traffic controllers.

42 Nimby is the acronym for 'not in my back yard'. In California in the context of power generation it evolved into 'Banana' – 'build absolutely nothing anywhere near anybody'.

43 On 3 June there was also a blowout on the Marcellus play in Pennsylvania which has sensitized public opinion as parallels are drawn with the Macondo blowout.

44 To put this into perspective, a golf course uses between 300,000 and one million gallons per day.

45 An important key indicator of such a revolution will be what emerges out of the contracts being played out in Southeast Poland, as mentioned earlier.

Chinese CBM production will be around 5 billion cfd by 2030, which would represent some 18% of total domestic supply.[46] Recently shale gas has also begun to emerge as a subject of interest. There are clearly barriers to development in China along the lines discussed above. However, many of the constraints outlined for Europe are constraints simply because they involve opposition from people and local communities whose voices and views must be taken into account. It is likely that the situation in China will be rather different. Many of the barriers can simply be swept away by a government determined to promote domestic supplies of gas. Perhaps the greatest constraint in China is the ability to access and use the necessary technology, although in November 2009 it was reported that President Barack Obama had agreed to share US shale technology and help promote the activities of the US industry in China.[47] It remains to be seen what may develop from this commitment since there are also concerns about the availability of water in areas of China that may be geologically prospective for shale gas (Zhang, 2010). In April 2010, the Chinese Ministry of Land and Resources announced that the pioneer shale gas field in Chongqing – on which the Strategic Research Center for Oil & Gas Resources and the University of Geosciences have been working since 2004 – will start commercial production in 2011. The ministry has a goal of building up its total shale gas production capacity to 3–5 bcm from 10–15 leading shale gas fields by 2015. A further expansion to 15–30 bcm from 20–30 dominant fields is planned by 2020. This would make shale gas production equivalent to about 8–12% of the total annual domestic natural gas production (Zhang, 2010). At the end of June 2010 India announced it was to offer exploration acreage for shale gas for the first time.[48] An expert is to be appointed to consider which areas may be offered and also what the regulatory regime might look like. India's petroleum legislation, like Europe's, ignores unconventional gas, but it is expected that the first licences may be granted within a year.

According to FACTS Global Energy, India's government is very excited about CBM, and the country's reserves potential. According to a 2009 government presentation,[49] India's CBM gas resources are estimated to be 3.4 tcm, tantamount to a potentially vast new source of indigenous production. Current production levels are modest, at 0.15 MMm3/d, but over two dozen blocks have already been allotted for commercial development, and a dozen or so are on offer.

As far as shale gas is concerned, India is also excited about production potential, and intends to hold an auction for shale gas acreage in August 2011. Several basins – Cambay (in Gujarat), Assam-Arakan (in the northeast) and Gondwana (in central India) – are known to hold shale gas resources. The Director General of Hydrocarbons and the Minister of State for Petroleum and Natural Gas are studying worldwide fiscal and contractual regimes in order to frame an Indian shale gas regulatory framework, which the government hopes to have in place by the end of the current financial year. This will enable it to amend the Petroleum and Natural Gas Rules, which govern the oil and gas exploration activity, prior to the auction.[50]

46 Private communication.
47 *The Economist*, 13–19 March 2010.
48 *Bloomberg Businessweek* website, 12 July 2010.
49 Reported in *Energetica India,* March/April 2010, pp. 42–43.
50 Private communication from FACTS Global Energy.

4. Implications of the Shale Gas Revolution for International Gas Markets

This chapter explores the likely impact of recent developments associated with the shale gas revolution, and the accompanying uncertainty, on the future development of international gas markets.

Capacity under-utilization

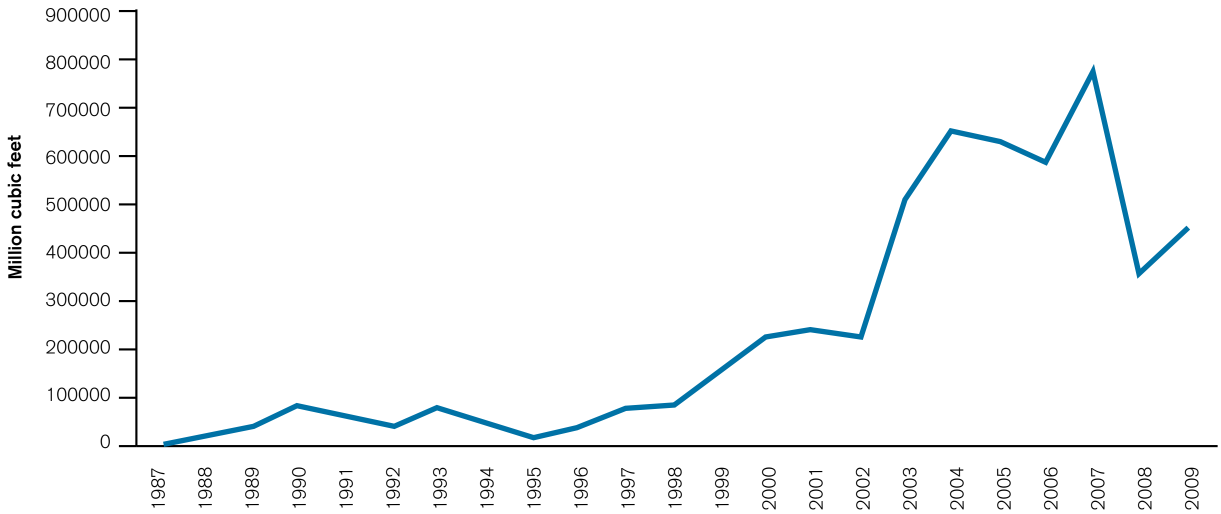
The shale gas revolution has already had a serious impact on LNG capacity utilization. As a result of gas market conditions around 2007, as described above, a surge in LNG export and import capacity was expected. PFC Energy has estimated that export capacity would increase from 200 mty in 2008 to 285 mty in 2012 and to 300 mty on 2013 (Tsafos, 2010). The IEA described this as an 'unprecedented period of expansion' in LNG export capacity (IEA, 2009: 438), with the largest ever plants due to be commissioned and 147 bcm under construction in 11 countries – all due on-stream in 2013.[51] Even more capacity was expected in the longer term. The forecast for 2020 in Jensen (2009) suggests a 'high case' LNG capacity of 450 mty and a 'low case' of 300 mty. Much of this increase in capacity was expected to supply the US market. Thus in Jensen's 'low case', it was assumed that North America would account for 30% of the growth in LNG demand. This is now all looking extremely optimistic, depending upon the view taken of whether the shale gas revolution can continue in the United States. Figure 8 illustrates the recent decline in LNG imports. While this is in part due to the lower gas demand in the United States as a result of the recession,[52] part is due to the rise in shale gas production, as shown in Figure 6.

The result has been a dramatic under-utilization of US regasification capacity. Over the last 10 years, this capacity has increased more than tenfold to reach over 100 mty in expectations of domestic gas shortages; however, the increase in shale gas production by over 5.5 bcfd is equivalent to some 41.25 TY of LNG (Meagher, 2010). The IEA estimated that in 2008, six regasification plants were under construction, amounting to 69 bcm per year, and a further 19 plants with a total capacity of 280 bcm per year had received approval (IEA, 2009). In 2009, the average utilization of the existing regasification capacity was only 9.3% (Meagher, 2010). The result is that a great many private investors in LNG in the United States have suffered considerable losses.

This development of over-capacity is a global phenomenon (Hulbert, 2010). There was a general reduction in global gas demand by 70.4 bcm (BP, 2010) as the result of the recession, leading to a significant over-supply of LNG capacity and supply, together with a reduction in the throughput of pipelines. The situation will be aggravated as Qatar's RasGas III and RasGas IV 'trains'[53] come on-stream in the second half of 2010. It is estimated that this will increase Qatar's LNG capacity from 54 mty to 77 mty – equivalent to around 30% of total global capacity.[54] Furthermore, these two trains were specifically aimed at the United States, which implies a further weakening of the LNG market (Von Kluechtzner, 2010).[55] According

51 For details see IEA (2009).
52 In 2009, US domestic gas consumption fell by 1.5% relative to 2008, from 657.7 bcm to 646.6 bcm (BP, 2010).
53 A 'train' is simply the technical term for an LNG processing unit.
54 Private communication
55 It is likely that a portion of the output of these trains was always intended to be diverted to premium Asian markets.

Figure 8: US imports of LNG



Source: US Energy Information Administration, http://www.eia.gov/.

to estimates by the IEA (2009), there will be an under-utilization of interregional gas pipelines and LNG capacity amounting to 200 bcm between 2012 and 2015, compared with 60 bcm in 2007. Such growing surplus capacity will not be good news for private investors in gas transport. Because of the high fixed costs that characterize both gas pipelines and LNG projects, full-capacity operation is essential to maintain profitability. Prospects of below-capacity operation would normally act as a significant deterrent to further investment.

An immediate consequence of this extremely weak LNG market is that forecasts of future LNG capacity are being dramatically revised. For example, the consultancy company Wood Mackenzie's forecast for 2010 was down 14% on its 2007 forecast (by 37 mty to 220 mty) while its 2020 forecast is down 28% to 360 mty from the 2007 forecast (Meagher, 2010).

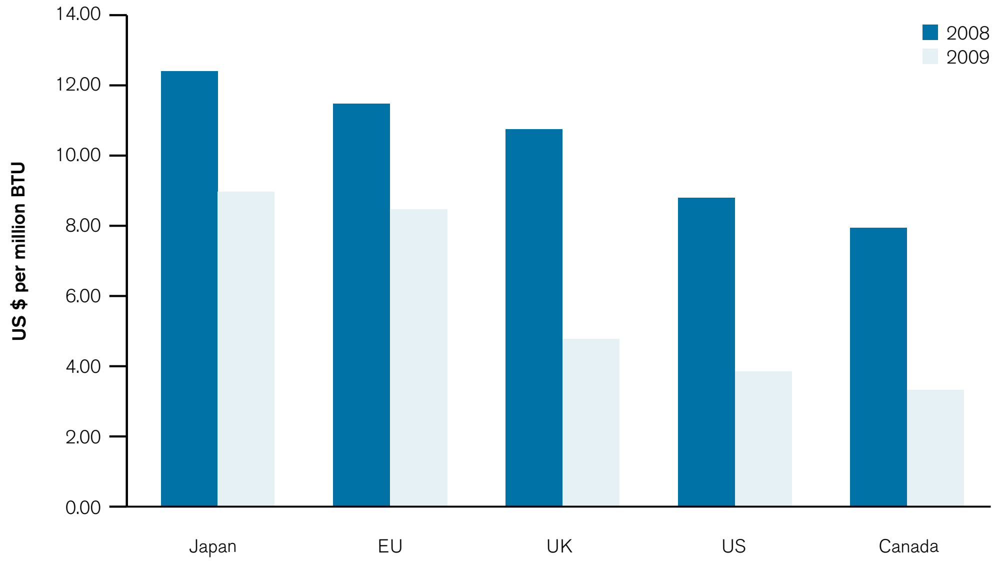
While this excess capacity is a global issue, the position of the United States is crucial despite the fact its market share has been quite small. Jensen (2009) estimated that in 2007, the United States accounted for only 10% of global LNG trade.[56] However, it is effectively the residual market for LNG in the context of spot trade. An important driver of the LNG capacity expansion seen in recent years was the prospect of getting spot cargoes into the United States during domestic gas price spikes of the sort that, as can be seen from Figure 5, have been both very high and quite frequent since 2000. Such a trade would be extremely profitable, especially if a base-load US demand could be assured as a result of declining domestic gas production. The shale gas revolution clearly throws such prospects into doubt, although weather and cyclical factors are still likely to create price spikes in the United States.

Prices

The current LNG glut has caused gas prices generally to fall dramatically, as shown in Figure 9. This is not entirely due to gas surpluses given the contractual link in many markets between oil prices and gas prices. In Japan and the EU, the fall in gas prices was 28% and 26% respectively, while the fall in oil import costs (based upon an energy content comparison) was 38%. By contrast, the fall in the United Kingdom was 55%, in the United States 56% and in Canada 58%.[57] However, there are clear signs

56 FACTS Global Energy, in a private communication, put this number at 9.2%.
57 Computed from BP (2010).

Figure 9: Domestic gas prices, 2008-09



Source: BP, 2010

of much lower LNG prices in terms of spot transactions. In July 2010 *Bloomberg Businessweek* reported that China had purchased a spot cargo of LNG at $4.3 per million BTU, the lowest it had paid since entering the LNG spot market in April 2007.[58] Lower prices are reinforced because spot charter rates for LNG tankers are at very low levels, reflecting current over-supply. Indeed, a London ship-broker is reported to have claimed that 'spot charter rates are low, so storage on ships will happen and is happening.'[59] The over-supply is the result of mismatches between LNG projects start-ups and the completion of LNG tanker construction combined with the expiry of charter agreements for older tankers as a result of production declines in older projects.

The growing LNG surplus in northern Europe is also reflected in much lower gas prices generally as a result of competition.[60] Russian gas prices at the German border fell 30% in the third quarter of 2009 compared with 2008, and the Dutch prices at the TTF Hub (Germany's western border) by 55% (Jensen, 2009). There appears to be a mutually reinforcing process at work. In Europe, the increasing attempts by gas buyers to bring local prices into LNG pricing negotiations are generating downward pressure. There are also pressures for pipeline suppliers to include spot prices in their pricing formula. One source has suggested that this is creating sufficient uncertainty for LNG suppliers to argue that this 'could undermine investment in new producing capacity' (Crompton, 2010). This undermining of investment is being reinforced by a view that gas demand is still suffering in a Europe that is attempting economic recovery, and by growing support for nuclear power and renewable energy sources.

The gas price prospects in the United States are equally uncertain in the near term. As the 'destination of last resort' (Tsafos, 2010), the current LNG surplus is likely to find its way into the US market, keeping US domestic gas prices low. The situation is even more uncertain than usual in 2010: between April and mid-July, Qatar undertook a massive maintenance programme that affected up to half of the country's 54 mty LNG capacity. According to Reuters this was the 'key balancing factor in the global LNG markets'.[61] As indicated above, in the second half of

58 *Bloomberg Businessweek* website, 22 July 2010. While in Washington in early May, the author heard rumours of a spot cargo going for $3.50 per million BTU.
59 *Bloomberg Businessweek* website, 22 July 2010.
60 Obviously lower oil prices also played a role given the contractual linkage with gas prices.
61 http://in.reuters.com/article/idINN1414158220100714.

the year, Qatar's export capacity is set to increase substantially as a result of both the end of that maintenance programme and new capacity coming on-stream.

Some observers have gone as far as to suggest that markets are on the verge of a price war as a result of surplus LNG capacity and surplus US domestic gas production (Jensen, 2009). Certainly there are clear signs of a de-linking between gas and oil prices in the project supply markets (Stern, 2009),[62] although FACTS Global Energy claims that while gas and oil prices may diverge in the West, in the East they will remain connected by virtue of being oil-indexed.

There are also uncertainties over costs that obviously feed into uncertainties over future profitability. There are claims that shale gas costs are falling and in some cases in the United States they are below those for conventional gas. Thus Haynesville shale is seeing costs as low as $3 per million BTU, down from $5 or more in the Barnett shale in the 1990s (Jaffe, 2010).[63] However, the fiscal regime on US shale gas is also being tightened. The governor of Pennsylvania, Ed Rendell, is determined to increase royalty and severance tax payments, although the proposals are struggling to get through the state Senate despite being passed by the state House of Representatives. The state is also seeking to increase the bonding requirements,[64] which were set by the Oil and Gas Act of 1984 at $2,500 per well (or $25,000 for unlimited wells). One proposal is to increase the bond for unlimited wells to $250,000. Such efforts are likely to be redoubled and sights set on much higher values in the light of the Macondo spill in the Gulf of Mexico. Future costs are also likely to be greatly influenced by the outcome of the current set of studies on hydraulic fracturing and the potential regulatory consequences.

A possible consequence of current price developments relates to the potential for the creation of an Organization of Gas Exporting Countries. Eleven gas-exporting countries attended the first ministerial 'seminar' in Tehran in 2001 which resulted in the establishment of the Gas Exporting Countries Forum (GECF), and a number of subsequent changes. Since 2007, Russia has become much more seriously engaged; the December 2008 GECF meeting apparently saw a formal signed charter document; and in 2008, Russia, Qatar and Iran created a 'gas troika' (Stern, 2009). GECF has now created a permanent headquarters in Doha, led by a Russian, Leonid Bokhanovsky. Inevitably, there has been constant speculation about the possibility of the GECF turning into an OGEC and trying to behave like a cartel. Clearly, there are major barriers to such a development. It is not clear, for instance what benefits there would be for a country to join rather than simply free-ride. Non-OGEC gas suppliers would create intense competition, leaving the active members to defend prices. Nor is it clear on what basis the cartel would try to fix the market – production quotas or price-setting – or how it would try to manage the inevitable problem of cheating. In addition, very large volumes of traded gas are subject to long-term contracts with rather rigid pricing and delivery terms that are protected and enforced by international commercial laws. Government intervention in pricing terms would violate such contracts and, so far at least, parties to the agreements have not hesitated to use international arbitration to resolve their contractual disputes.[65] Moreover, while it would be possible to restrict over-production of LNG from entering the spot market, what constitutes a 'spot market' (Aissaoui, 2006)? And what of countries that have selectively concentrated on the spot market: would they be forced to absorb most of the reduction?[66]

Despite these concerns, current gas market conditions as a result of the shale gas revolution mean the issue of an OGEC may well come to the fore. As the current linkage between oil and gas prices weakens, GECF

62 There is an argument that spot LNG may well be held back in coming years because in times of major uncertainty, sticking to traditional contractual arrangements wherever they exist or apply would be less risky and less costly.

63 However, it is worth remembering that, as outlined earlier, shale plays (and indeed wells within the same play) are very different in terms of their geology and hence their operating environment. Cost patterns cannot necessarily be extrapolated from one place to another.

64 This is the requirement to place a deposit to ensure compliance with lease terms and conditions and ensure the management of 'orphaned wells' (GAO, 2010).

65 A point made privately to the author by Ali Aissaoui.

66 All these issues have been raised by Jim Jensen in various communications between himself and Ali Aissaoui.

might be encouraged to attempt to propose its own price mechanism (Stern, 2009). Equally, if prices stay low or go even lower and the exporters' revenue is squeezed, there is a strong incentive for GECF to step in to try to defend falling prices. After all, it was precisely this mechanism that prompted the creation of OPEC in 1960.

Some such as Jaffe (2010), have argued that the shale gas revolution will prevent a cartel because it increases the number of suppliers and that shale gas will breed competition. However, this neglects the fact that new countries entering markets as a result of unconventional gas will be small players and in most cases interested only in developing gas for domestic consumption. The main barrier to an OGEC may be that the greatest support for such an idea from within GECF comes from two countries – Iran and Venezuela – whose antipathy to the West would probably make other countries reluctant to enter into close association with them.[67] Both, as pointed out in Stern (2009), are also marginal gas suppliers to the international market.

Investments and future uncertainties

The key question is whether all this uncertainty in gas markets will inhibit future investments. It is already clear that investment plans for gas transport projects are currently being reduced. In 2010, Wood Mackenzie estimated that more than a quarter of the LNG projects expected in 2007 would be pushed back, an estimate that it regarded as 'conservative'; it also suggested that by 2020 total LNG supply 'may well be closer to 300 mty than 400 mty' (Meagher, 2010: 17).

In similar vein, on 15 February 2010 Reuters reported that the development of the giant Shtokman field in the Barents Sea north of the Kola Peninsula – a joint venture between Gazprom, Statoil and Total – would be delayed. The project envisaged an annual production of about 70 bcm of natural gas and 0.6 MT of gas condensate. Shtokman's first phase involved annual production of 23.7 bcm of natural gas and investment of at least $15 billion. The original plan was to create an LNG project with the United States as the target market. Subsequently, it was decided to include an export pipeline to Europe. Citing 'changes in the market situation and particularly in the LNG market', the partners have now agreed to delay pipeline gas production until 2016 from an earlier target of 2013, and to postpone the start of LNG production from 2014 to 2017. Such reductions in or postponements of investment are likely to become commonplace.

The key uncertainty in the United States is the extent to which the current rise in shale gas production can be increased or indeed even maintained. It has already been pointed out that gas from shale plays has a much faster rate of depletion than gas from conventional fields.[68] Thus the old adage regarding investment in oil and gas – that the producer must run to stand still because of natural depletion – appears to be magnified in the context of shale gas. As long as profitability is high this is not a problem. However, the collapse in US domestic prices will clearly take its toll. It has been suggested to the author that many of the smaller companies on the shale plays are struggling to stay viable. It has also been claimed that 'some unconventional gas plays will be hard pressed to compete with imported LNG, especially for companies not at the top tier of the production curve'[69] (Tsafos, 2010: 19). This raises an interesting issue. As already explained, the *Economist's* 'bygones rule' determines whether or not loss-making companies close. Provided they are covering variable costs, logic requires continued operations. For most oil and gas operations, variable costs are small and fixed costs are large, which means companies will bear losses for long periods. However, in the case of shale gas, the requirement for a much larger number of wells and the rapid decline rate on fields mean that drilling might almost be regarded as a variable rather than a fixed cost.[70] Thus shale gas

67 More recently, Algeria has been showing signs of support for some sort of cartelization (Hulbert, 2010).

68 Although it is worth remembering, as mentioned earlier, that shale gas technology continues to evolve and this may slow depletion rates in the future.

69 This refers to companies struggling with costs.

70 It is worth remembering that a fixed cost is 'fixed' by virtue of contractual obligations to meet payment. As the contractual obligation lapses, the 'fixed' cost becomes 'variable'.

companies making losses are more likely to close sooner rather than later.[71]

Against this is the fact that recently, as described earlier, it is the very large companies that are now buying into shale operations on a grand scale. These companies, with much deeper pockets than the small independents, will clearly be able to ride losses for longer, especially given their large outlay to enter the game.

Another major threat to the shale gas revolution in the United States is the prospect of much greater environmental legislation that could seriously inhibit the use of hydraulic fracturing. Surprisingly, given the strength of the environmental movement, the issue of potential water-table contamination appeared to slip under the radar. But groundwater issues have always been extremely sensitive in the United States and now there is considerable research assessing the potential damage. A recent study by the World Watch Institute has concluded that:

> the most significant environmental risks associated with the development of shale gas are similar to those associated with conventional onshore gas, including gas migration and groundwater contamination due to faulty well construction, blowouts, and above-ground leaks and spill of waste water and chemicals used during drilling and hydraulic fracturing (Zoback et al., 2010: 1).

However, if other studies currently under way conclude there are dangers, this will create an instant tension between Washington's concerns over energy security of supply, and hence desire to maintain the shale momentum, and local communities' concerns for the environment. The experience of, for example, offshore oil activities in the United States suggests that it is the local communities that win such conflicts.[72]

The uncertainty in the rest of the world is over how far the shale gas revolution can be replicated. This report has presented a list of potential barriers to such an outcome in Europe. Certainly the stakes are high and the potential for government intervention is large. Over the last ten years, the European Union has become increasingly concerned about growing gas import dependence, especially since the problems experienced with the transit of Russian gas exports through Ukraine. Much of the discourse over energy policy following the EU Green Paper on energy security published in November 2000 has been aimed at addressing such issues (EU, 2009).

However, it is not clear whether the European Commission, at this stage, is willing to intervene actively to encourage the development of shale gas.[73] After all, it has been extremely reluctant to help solve the gas import problem by giving serious financial support to alternative pipelines that, by virtue of creating diversity, would also help to solve problems associated with gas imports.[74] The dilemma over pipelines can be easily explained. The benefits of alternatives to Russian gas imports, such as the proposed Nabucco pipeline via Turkey, will accrue to the governments of the gas-importing Europeans. This is true even if the line only operates at a fraction of its capacity. Its presence, based upon the 'contestable market hypothesis', would be sufficient to ensure reasonable behaviour on the part of Russia as a gas supplier and other countries which offer transit. However, if it is privately built, the costs will fall on the private investor. Unless those investors can guarantee close to full-capacity operation, given the very high fixed costs, the line will never be profitable. If the European Commission is unwilling to commit public money in this context where the benefits are obvious, then to do so for shale gas, given the much higher associated risks, seems unlikely.[75] Despite this,

71 Of course, given the existing infrastructure and access to the gas networks, entry is also likely to be easier in response to short-term market movements.

72 A good example was the fact that relatively minor Californian offshore oil spills (where there have always been significant natural oil spills from geological leakage) in 1969 (Santa Barbara) and1989 (Bolsa Chica State Beach) effectively stopped all offshore operations until today.

73 It is also not clear whether the Commission would help or hinder given that the exploitation of natural resources is reserved for member states. Where it could make a difference is in terms of environmental regulations.

74 This is complex. If it is believed that Russia has no interest in cutting off supplies to Europe, then the alternative routes being proposed by Gazprom – Nord Stream and South Stream – would be sufficient to neutralize the threat from transit via Ukraine, thus making Nabucco irrelevant. However, given that part of the benefit would come from competing gas supplies potentially offering lower prices, then in so far as Nabucco provided alternatives to Gazprom, the benefits would still be present. In any case, it is not clear how confident the European Commission is about the extent to which Russia might or might not use gas supplies as a political lever.

Poland's foreign minister, Radoslaw Sikorski, has stated that shale gas should be at the heart of the EU debate on energy security (quoted in Kefferputz, 2010). Poland imports roughly 72% of its natural gas from Russia (Kefferputz, 2010).

In this current phase of exploration in Europe, uncertainty is extremely high. Even if some progress is made and commercial discoveries are declared, it will still be some time before future supply patterns on any scale might be discerned. This uncertainty over timing is reinforced because the initial, currently very limited, exploration phases are unlikely to raise much serious local opposition. However, once development begins in earnest it will be a very different story, especially given the lack of any overarching effective regulation. This will be strongly reinforced if the United States decides to tighten its regulations on hydraulic fracturing.

Outside Europe there are also uncertainties. To what extent will governments be willing to impose their will on reluctant local communities in the name of energy security? How far can the required technology be transferred and operated effectively in specific circumstances? How far can the local gas markets offer attractive terms to private investors? The list could continue.

75 Indeed signals from the European Commission have been discouraging on this point. At the Global Shale Gas Summit in Poland on 19 July 2010, the European Commission's Michael Schuetz (Policy Officer, Indigenous Fossil Fuels, Directorate-General for Energy) was asked how the European Union might assist in the development of shale gas in Europe. He replied that it was not the EU's job to nurture the technology, adding that 'the industry has to develop this business': http://naturalgasforeurope.com/global-shale-gas-summit-day-1-overview.htm.

5. Conclusions

Because of the shale gas revolution, there are now huge uncertainties for investors at all stages of the gas value chain. Whether to invest in conventional gas production? Whether to invest in new pipelines and LNG plant? Whether to invest in other gas infrastructure such as storage? Whether to 'invest' in long-term supply contracts? All of these uncertainties are likely to lower investment levels, especially in conventional gas supplies. The current low gas prices will also reinforce such lower investment levels. Uncertainties over unconventional gas are generating other uncertainties, in particular over the issues of environmental legislation over hydraulic fracturing, the rate at which the new technology will develop and reduce costs, and to what extent the US experience can be replicated elsewhere.

From this uncertainty two major problems arise. First, energy demand will resume its inevitable pattern of growth as the world recovers from the worst global recession since the 1930s. As constraints on using gas continue to erode, gas demand will continue to grow and probably gain ever greater shares in the global primary energy mix. However, given investor uncertainty, investment in future conventional gas supplies will be lower than would have been required had the shale gas revolution not happened, or at least had not been so hyped. If it continues to flourish in the United States and is replicated elsewhere in the world, this inadequate level of investment in conventional gas will not matter. Consumers can look forward to a future of cheap gas as unconventional sources fill the gaps. However, if unconventional gas fails to deliver on current expectations – and we will not be sure of this for some time – then in ten years or so there may be serious constraints on gas supply. Markets will eventually solve the problem as higher prices encourage a revival of investment, but given the very long lead times on most gas projects consumers could face high prices for a considerable time.

The second problem of investor uncertainty concerns renewables. There is general agreement that the world will have to move to a low carbon economy if climate change is to be controlled. Among other things, this requires considerable investment in renewables in power generation. Thus:

> energy and infrastructure investments made in the next 10–15 years will largely lock in the greenhouse gas emissions trajectory to 2050. This alone creates an immediate pressure to accelerate investment into clean alternatives (Hamilton, 2009: 2).

There were signs that this process was beginning to get under way: in 2008, investment in new renewables in power generation (including large hydro projects) for the first time exceeded investment in fossil fuel power generation (Hamilton, 2009). The IEA has estimated that if the 450 Scenario[76] is to be achieved, then by 2020 an extra $88 billion must be spent in the power sector (IEA, 2009).

The failure of the Copenhagen talks on climate change mitigation has injected considerable uncertainty into the investment climate for power generation, not least because of the uncertain prospects over what the future price of carbon might look like. This has now been reinforced as the Macondo oil spill in the Gulf of Mexico has thrown the prospects for a cap-and-trade system in the United States into doubt, given that access to offshore oil exploration was a key chip in the bargaining game between Democrats and Republicans. The uncertainties created by the shale gas revolution have significantly compounded this investor uncertainty. In a world where there is the serious possibility of very cheap, relatively clean gas, who

76 This is a scenario in which the long-term concentration of greenhouse gases in the atmosphere is limited to 450 parts per million of CO_2 equivalent and the global temperature rise to around 2°C above pre-industrial levels. It is the closest that the IEA has yet come to a low carbon future.

will commit large sums of money to what are for the most part extremely expensive pieces of equipment? This is especially relevant, for example, in the United Kingdom, where a debate is currently under way over whether to build replacement nuclear power stations in a situation where conventional domestic gas supplies appear to be in terminal decline and much of the generating capacity requires replacement.

Appendix: A History of Constraints in Gas Markets

The serious constraints on gas mentioned in the text, and the recent erosion of these constraints, are explained more fully in this appendix.

First, relative to the other hydrocarbons, because gas is a high-volume, low-value commodity, it is extremely expensive to transport. Figure A1 illustrates gas transport costs relative to those for oil and coal. If a country or region did not have physical access to gas or was located far from a gas-producing province, no gas would be consumed.

In the mid-1970s, a view gained ground in Washington and Brussels that since gas was such a valuable, versatile and important fuel it should not be simply 'burnt' but should be reserved for 'special' uses. This 'premium fuel' argument led to legislation in the EU and the United States against the burning of gas in new power stations.

In the OECD, outside the United States, there was yet a further constraint. In most cases, national gas markets were dominated by monopolist and monopsonist state-owned utilities. By their nature they tended to use this dominant position to act as satisficers rather than profit-maximizers.

Constraints also arose from the policies and politics of gas-consuming countries. In the late 1970s, there was an expansion of nuclear power and, in many countries, the pursuit of a strong coal utilization strategy under the banner of 'security of supply'. There was also strong pressure from the Reagan administration to prevent Soviet gas imports into Western Europe. In June 1982, using the pretext of a coup in Poland, the administration announced expanded economic sanctions against Soviet gas export pipeline projects. This banned the transfer of relevant US technology involving both US subsidiaries abroad and foreign companies working under American licences.

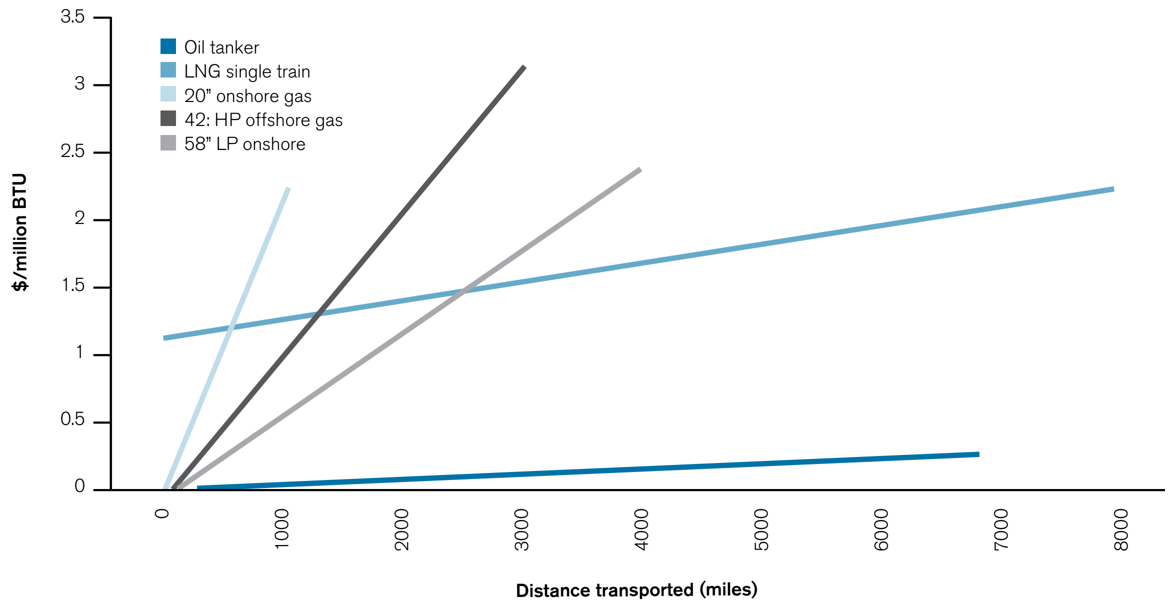
In the developing world there were further constraints on the entry of gas into the primary energy mix. The debt crisis which affected many developing countries in the 1980s meant that countries where gas had been discovered could not afford the very large capital expenditure to develop the gas infrastructure for domestic use. For many governments debt financing was simply not an option. And in many cases the government was a monopsonist buyer of any gas found and often set prices very low to benefit consumers. Also there was what became known as the 'foreign company problem'. Foreign companies discovered the majority of these gas reserves. Domestic use, say in local power stations, meant the gas would be paid for in local currency. If this was non-convertible, then although the projects were extremely profitable in terms of an internal rate of return, the companies had no interest in pursuing them, since their shareholders could not be remunerated.

For gas-producing developing countries, there were also significant constraints on export options. Gas export projects need minimum levels of certified, proved reserves to make them viable.[77] Often the reserves found were below this level and the 'foreign company problem' inhibited further exploration.[78] There were also serious problems with negotiating contracts. Historically there have been two types of gas market into which exporters could try to sell: a commodity gas supply market or a project gas supply market. In the former a large number of buyers and sellers

77 Estimates vary but in rough terms a pipeline supplying 2 billion cubic feet per day (cfd) needs reserves of at least 15 trillion cubic feet (tcf), while 1 tcf of feed gas is needed to support 1 million tons per year of LNG production over 20 years.

78 In the 1980s discovering gas rather than oil was regarded as bad news for the companies. Gas was seen as a problem rather than a blessing. Such views began to change in the 1990s as gas markets started (in some cases) to look more attractive, but the legacy remained.

Figure A1: Comparative transport costs



Source: Jensen (2004)

of gas operated in a relatively transparent market. Thus there existed a 'gas price' upon which to base the export contracts. Unfortunately there were few such markets.[79] Most markets were project supply market where there were few buyers and sellers, and poor transparency. Thus there was no 'gas price' upon which to base the contract price. This seriously complicated negotiations. Pricing was based upon some sort of formula in terms of potentially competing fuels (usually oil). However, in the early contracts there was sometimes a requirement to fix an absolute floor price to protect the supplier and an absolute ceiling price to protect the buyer. Given that these were very long-term contracts negotiations were difficult, to say the least, and sowed the seeds of many subsequent conflicts over export terms.[80]

There were also problems with transport for gas exports. Gas pipelines suffered in some cases from serious and endemic conflict in transit countries (Stevens, 2009).[81] Until relatively recently problems with LNG too were serious enough to constrain projects.[82] The projects were complex and extremely expensive. LNG requires lowering the temperature of the natural gas to –161 degrees Celsius.[83] The engineering tolerances with such temperatures are extremely small, making the technology highly complex. Projects were also extremely energy-intensive, with somewhere between 15% and 18% of the gas input simply going into the whole LNG chain.[84] Also, projects had to involve all stages, from wellhead to final customer; it was not feasible to think in terms of investing in only parts of the value chain. All output

79 Even today, only the US, Canada and the UK can be described as real commodity supply markets. Argentina has some characteristics of such a market but there are also destructive price controls. This explains why Argentina is an LNG importer and why there is little interest in developing its domestic gas potential. Jensen (2009) identifies several conditions which need to be fulfilled for a commodity supply market to develop: the availability of competitive gas; a free choice of supplier available to consumers; and an open transmission system that does not discriminate.

80 In later contracts, more commonly there was an 'S curve' with sloping floors and ceilings rather than fixed numbers.

81 To be fair, until recently most of the problems of transit pipelines were associated with oil rather than gas lines. However, the poor record of oil lines did inhibit the prospects for gas transit pipelines.

82 As discussed below, many of these problems and constraints were being removed, making LNG projects relatively more attractive.

83 To give an idea of how cold this is, if a sheet of steel were lowered to this temperature, hitting the frozen sheet with a hammer would cause it to shatter like glass.

84 Of this around 9% is required for the actual liquefaction process.

had to be committed in long-term contracts. Spot trade was unthinkable. The result was that in the 1970s and 1980s LNG projects were extremely expensive relative to other energy projects. They also had extremely long lead times.[85] Because of the very high capital intensity, full-capacity operation was crucial. Therefore before the plant could even be designed, let alone built, all the output had to be sold on the basis of long-term contracts, and negotiating contracts could literally take years. Accumulating the large amounts of finance for such large projects could also take a very long time. In the LNG projects which came on-stream in the 1990s, lead times of 20–25 years were not unusual.[86] A major consequence of these long lead times and the complexity of the contracts was that the trading links were very inflexible. As market circumstances changed, LNG contracts became very vulnerable to conflict over the terms. Finally, as if these problems were not enough, for the owner of the gas there was very little revenue in LNG. The effective gas price at the wellhead was extremely low and the economics of most LNG projects was highly dependent upon the value of the liquids stripped out of the wet gas (Stauffer, 1997; Bartsch, 1998). Thus before the 1990s, LNG was a tough option for exporting gas.

As a result of all these constraints, as can be seen from Figure 1 in the main text, gas penetration into the global primary energy mix was extremely limited. The exception was in the former Soviet Union, where gas did gain market share, but this was simply because of the policy of making it extremely cheap.[87] Thus even as late as the early 2000s, the Russian domestic price for gas (including the prices charged to former Soviet republics) was a quarter of the export price (Jensen, 2010).

The constraints begin to weaken

During the 1990s many of these constraints inhibiting the use of gas began to erode, for a number of reasons.

In 1990, both the US and the EU dropped the legal restriction on gas use in power generation. The result, for example in the UK, was what became the 'dash for gas' (seen clearly in Figure 3 in the main text. In many countries the electricity sectors were undergoing reform. This was specifically aimed at attracting private-sector investment in generation that in many cases was suffering from gross under-capacity (Schramm, 1993). Such private investment would invariably pick gas, if available, as the fuel of choice given the huge benefits of CCGT to the private investor.[88] Thus in 2007, 39% of gas consumption was in power generation, and this was expected to rise by 1.7% per year, reaching 41% in 2030 (IEA, 2009).

At the same time, growing concern about environmental issues made gas look an increasingly attractive option, especially in the context of the CO_2 emission targets set at the Earth Summit in Rio de Janeiro in 1992 and in the Kyoto Protocol in 1997.

Many countries were also trying to reform their gas sectors with the aim of moving them closer to a commodity supply market, since, other things being equal, this would make it much easier to manage export contracts.[89] Gas pricing in Western Europe has been undergoing significant changes, moving away from contractual links with oil prices (Stern, 2009; Jensen, 2009).[90]

There have also been some improvements in the ability to transport gas internationally. In terms of transit pipeline problems, developments as a result of the Energy Charter

85 Defining lead times can be controversial. Some would start the clock after the final investment decision (FID), others might start it from the time of the first announcement of the intention to develop a project.

86 The Nigerian LNG project was some 30 years in the making.

87 In 1965, based upon BP (2010), gas represented 18.7% of the FSU's primary energy mix. This rose inexorably to reach a peak of 60.1% in 2007.

88 These include the fact that small-scale CCGT plant are economic and have very high thermal efficiencies. They can be built very quickly – in less than two years – and at least in the US can be licensed very much faster than coal plant. All this implies they are subject to very quick payback for investors. For private investors considering involvement in countries where the political risk is perceived to be high this is crucially important.

89 In particular, the European Commission has been trying for a long time to convert the European gas market to one resembling a commodity supply market. In June 1998 it issued the first of its gas liberalization directives to try to break monopolies and create an open and competitive market. However, there are extremely powerful vested interests within the sector trying to resist these moves.

90 These had originally been based upon the Dutch policy for domestic gas pricing based on the value of the price of fuels displaced (Jensen, 2009).

Treaty (ECT) initially gave rise to some hope of collaborative solutions.[91]

The ECT came out of the Lubbers plan proposed in June 1991.[92] The European Energy Charter itself was simply a political declaration but the subsequent ECT in 1994 created a multilateral legal framework to guarantee private investments, operations and trade in the energy sector. This was originally intended to provide protection for investment by Western firms in energy projects in the former Soviet republics and to try to ensure that the collapse of the Soviet Union did not create chaos on the European energy market. However, during the course of negotiations the scope of the ECT was expanded to cover not only west-to-east energy investments but also east-to-west and eventually west-to-west investments. The treaty was signed in December 1994 in Lisbon and, following ratification by 30 signatories, came into force in 1998. However, three significant signatories – Australia, Norway and Russia – have yet to ratify.[93] Russia's non-ratification is clearly a major barrier to the effective operation of the ECT, but there are a number of stumbling blocks. Gazprom is concerned that the ECT provides the possibility of third-party access to the Russian pipeline network. This would 'open the door to uncontrolled transit of Central Asian gas to Europe' (Stern, 2005: 138). Effectively this would break the current *de facto* monopoly position on gas supplies from the East into Europe. At the same time, Russia is concerned about the French blockade against Russian nuclear material, which France sees as its monopoly. In general Russia appears to accept the transit and trade coverage of the ECT but is unhappy when this extends to investment issues.[94] Also it is likely that Russia sees ratification as a lever on other issues such as World Trade Organization membership.

A fundamental problem with the ECT is that it was negotiated in a hurry. Many contentious issues were glossed over to keep the negotiations alive (Waelde, 1996; Bamberger and Waelde, 1998). In particular, issues related to energy transit were extremely vague and lacked clear rules, despite the fact that the treaty was essentially trying to solve disputes over 'transit terms' without disruption of throughput.

After the adoption of the ECT, the governing body – the Energy Charter Conference – considered that its energy transit clauses could be strengthened by means of more detailed rules. In December 1999, the Conference mandated negotiations on an Energy Charter Transit Protocol (ECTP), and these began in 2000. However, they were complicated because of ongoing bilateral negotiations (including energy transit issues) between the EU and Russia in the context of Russia's attempts to accede to the WTO. Despite this, elements of an agreement on the ECTP were reached by the end of 2002.[95]

In June 2004, talks were resumed (Konoplyanik, 2004). A major issue clouding the ECTP negotiations continued to be the ongoing conflict between the EU and Russia over long-term energy supply contracts. The European Commission has long seen such contracts and destination clauses as a major impediment to one of its central objectives, competition in energy markets. By contrast, Russia sees them as essential for security of demand. In effect, it was decided that until these EU–Russian negotiations produced an agreement that could be presented to all the ECT member states there was little point in continuing ECTP negotiations in isolation.[96] However, in December 2007 the Conference asked the responsible group – the Energy Charter Group on Trade and Transit – to have 'multilateral consultations' on the draft during 2008.

The current situation with regard to the ECTP is extremely unclear. It is very unlikely that any resolution of the outstanding and complex issues will emerge in the near future.[97] Thus the possibility that the ECT could resolve transit problems seems remote.

91 What follows on the ECT and other means of transporting gas is taken from Stevens (2009).
92 For extensive details on the ECT, see the website http://www.encharter.org/.
93 In addition, a number of important players such as Algeria, Canada, Iran, Morocco, Qatar, Saudi Arabia, Serbia, Tunisia and the UAE, among others, are merely 'observers' to the Treaty.
94 For detailed background on these extremely complex issues, in addition to Stern (2005), see Belvi (2008) and Doeh et al. (2007).
95 The draft is at http://www.encharter.org/fileadmin/user_upload/document/CC251.pdf.
96 The Russian position appears to be that the correct context to discuss transit issues is within the ECT (Stern, 2005).
97 There is a view that Russia's energy agenda has little interest in the ECT or the Energy Protocol but rather is more concerned with the use of energy as a means to pursue state power. However, it is also likely that the profit motive remains important as a driver of Russian actions.

Other developments relating to gas transport might expand the international gas trade. These include compressed natural gas (CNG), gas-to-liquids (GTL), gas by wire and embodied gas.

CNG: This is natural gas that has been compressed to 1% of its original volume. It is then used as a substitute for liquid transport fuels such as gasoline and diesel. The use of CNG is spreading rapidly, not least because it significantly reduces particulate emissions from diesel; it is also well suited to fleet vehicles such as buses since the CNG filling facilities can be concentrated in one place. Since the process takes natural gas and compresses it before putting it into vehicles, it is not currently a very attractive option for exporting gas. However, CNG has around 40% of the energy content of LNG, making it easier and cheaper to handle, and therefore longer-distance transport by sea-going tanker could be an option for the future. Moreover, it is attractive for smaller markets and suppliers, and also for closer markets, given that tanker transport accounts for much of the cost of CNG. There is growing discussion in the technical press of the viability of CNG as a serious option for gas exports (Cano and Stephen, 2005).

GTL: Gas-to-liquids is a process that takes natural gas and, using technology based upon the Fischer-Tropsch process,[98] converts it to a liquid. In the late 1990s there was a huge amount of interest in GTL, with projections of very large increases in new capacity. However, since the product of GTL is a high-quality diesel, it competes in a different market from natural gas and as such is not strictly speaking a viable alternative for transit pipelines – except as a possible means for a gas producer to monetize its gas reserves. Also much of the earlier enthusiasm has been dampened by the rising costs of such projects. For example, according to *MEES*, the Pearl GTL project for a 140,000 b/d plant signed between Shell and Qatar in 2003 originally had a capital cost estimated at $6 billion, but by 2008 this had escalated to $18 billion,[99] and subsequently, according to trade press reports, appears to have risen to $19 billion.

Gas by wire: This is a process whereby electricity is generated on the gas field and then transported by high-voltage transmission lines. The logic is that it is cheaper to lay electric cable electricity than pipelines and thus a better means to monetize gas reserves.[100] The limitation lies in the transmission losses, which rise exponentially as the distance increases. It is likely that there will need to be a technological breakthrough in super-conductivity before this becomes a serious alternative to long-distance transit pipelines. Also it is arguable that problems associated with transit gas pipelines would apply equally to transit electricity wires.

Embodied gas: One alternative to direct export is to use the energy content of the gas in some energy-intensive process such as metal smelting, and to export the consequent product. The basis of this option is what has become called in the literature 'Resource Based Industrialization' (RBI). However, the record of RBI has often been poor, not least because it is governments that have created and operated the industrial base (Auty, 1990). As has been frequently remarked in many contexts, governments are bad at picking winners, and losers are good at picking governments. Also, like GTL, this is a mechanism to monetize gas reserves for the producer government rather than an alternative to a transit pipeline in the context of a global gas market.

Significant as these developments may be, the major changes with respect to transport and the reason for much of the speculation before 2007 regarding the nature of future international gas markets are connected with LNG.

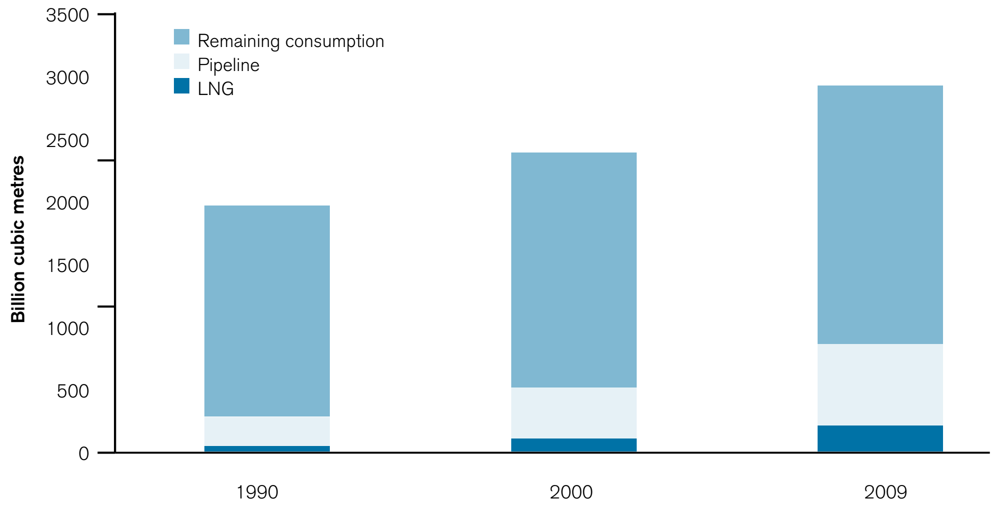
LNG developments

The erosion of many of the earlier constraints on the use of LNG as a means to export gas led in the 1990s to an increase in LNG trade (see Figures A2 and A3).

Several factors explain this change in the prospects for LNG and why even more was expected (Jensen, 2003). The use of much larger LNG processing plants created large economies of scale, reducing project costs significantly. For example, Jensen (2004) attributes around 40% of the

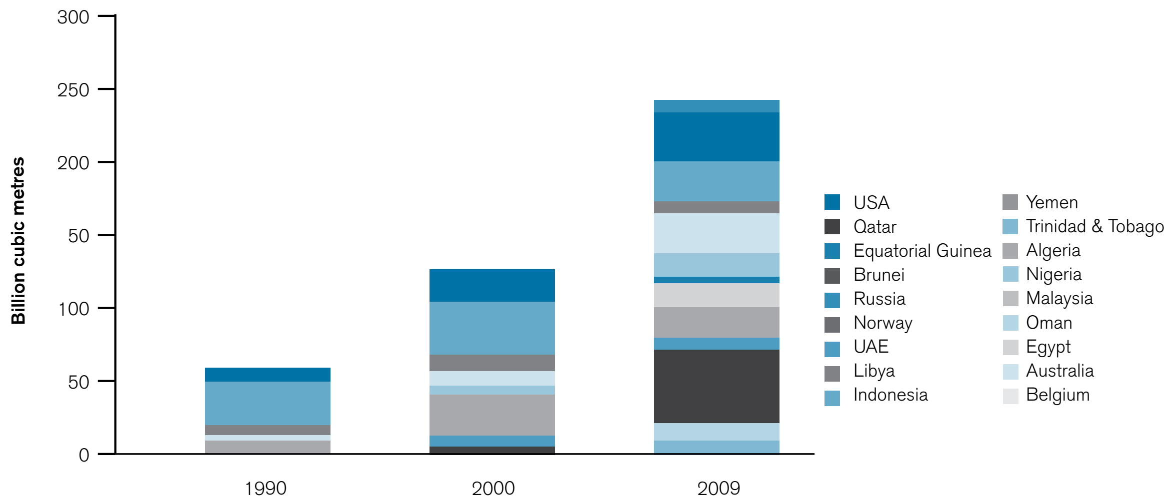
98 This was developed in Germany in the 1930s to convert coal into liquids by means of a catalysed chemical reaction.
99 *Middle East Economic Survey*, Vol. LI, No 23, 9 June 2008.
100 Another advantage is that any CO_2 from the power plant can be reinjected into the field as part of a carbon capture and storage programme.

Figure A2: Share of LNG versus pipelines in international gas trade



Source BP, 2010

Figure A3: LNG exports, 1990–2009



Source BP, 2010

lower capital cost per ton between a 1.8 million-ton train in 1980 and a 4.0 million-ton train in 1990 to economies of scale, and around 60% for a 7.55 million-ton train.

As for LNG tankers, their costs also fell as the emergence of South Korean shipbuilding capacity created competition with the Japanese. Thus in 1991 a 125,000 cubic metre tanker cost $2,200 per cubic metre to build. By 2004 a 138,000 cubic metre tanker cost $1,500 per cubic metre. Overall, a 2003 report from the Gas Technology Institute quoted by the US Energy Information Administration (EIA, 2003) claimed that liquefaction costs including transport had decreased by 35–50% since 1993.

However, these cost reductions began to reverse after 2004 as all oil and gas projects began to suffer from higher costs, reflecting serious capacity constraints in the service companies following very poor financial performances in the previous ten years.[101] Thus between 2004 and 2007 the cost of liquefaction plants increased by 58% per tonne of capacity, that of LNG tankers by 115% and that of regasification plants by 110% (Jensen, 2009). The 13 plants built between 2005 and 2008 cost $430 per tonne per year (TY) while those being built between 2009 and 2013 cost some $830 TY (IEA, 2009). Other sources put the cost of some plants which are due on-stream in 2011 at more than $1,000 TY.[102]

New methods of project finance also made securing capital much easier. This helped to reduce not just the cost of capital but also the long project lead times (as noted above, the difficulty of raising very large sums of capital on what were seen as highly risky projects had been one of the reasons for their protracted lead times). Thus from lead times in excess of 10–15 years, the time from final investment decision (FID) to start-up for some projects fell to as little as four years (Jensen, 2009).[103]

Another key factor behind the growth in LNG trade in the 1990s was that more LNG projects came on-stream, leading to greater flexibility. As can be seen from Figure A3, in 1990 there were relatively few LNG projects. Because of the need for liquefaction and regasification plants, all trade was based upon long-term contracts, typically between 15 and 25 years. Thus all the output of the gasification plant had to be sold, as did the throughput of the regasification plants to ensure full-capacity operation to spread the extremely high fixed costs over the maximum throughput; and the vast majority of the throughput of the plant had to be secured by contract before any construction began. However, as can be seen from Figure A3, as more projects emerged, 'spot trade' became a reality which emerged as the result of a number of factors. These included 'wedge volumes' from new trains, resulting from gaps between train start-up and offtake commitments reaching their plateau level; expiration of long-term contracts; buyer over-commitment; conservative liquefaction plant design allowing above nameplate design capacity production; contract and operational flexibility; and contract failure. It was precisely this prospect of growing spot trade in LNG that began to make such projects extremely attractive. If an LNG cargo could enter a market at short notice when the gas price was spiking, a great deal of money could be made.[104] Thus by 2008, nearly 18% of LNG trade was in the form of spot contracts (Jensen, 2009). The 'spreading' of gas price signals was beginning to make gas trade look increasingly global.

This dramatic expansion in LNG before 2007 was greatly encouraged in 2005–06 by what Jim Jensen called a 'perfect storm' for LNG (Jensen, 2009) – the combination of Hurricanes Katrina and Rita; the UK becoming a net gas importer; a bad hydro-year for Spain, forcing greater gas-powered electricity generation; a very cold winter in Continental Europe; and very strong gas demand in Northeast Asia as the economies recovered from the recession of the late 1990s and India and China (and Mexico) began to import LNG. This expansion was further helped by efforts at diversification in the context of the Russia–Ukraine conflict, doubts about the Turkmen and Shtokman/Yamal investment programmes, and anticipation of a terminal decline in US domestic gas production. All these factors coming together led to competition for cargoes together with gas price spikes in Europe and the United States. As described in Chapter 5, the result was a dramatic increase in plans to expand LNG capacity to come on-stream in 2012–13. Jensen (2009) estimated his reference case capacity for 2020 at 375 mty, with a range from a high case (450 mty) to a low case (300 mty). Of this expansion, Qatar was expected to supply one-third of the firm to probable capacity between 2009 and 2012.[105]

101 This reflected the growing monopsony power of the major oil companies following their mega-mergers in the late 1990s and the growing use of e-commerce for contract bidding, which seriously squeezed project margins.

102 FACTS Global Energy, in a private communication.

103 This is defining the lead time as the time from the inception of the project. Arguably the time if measured from FID has not changed that much.

104 For example, the US Department of Energy reports that the average monthly city-gate price of gas in the US between 2000 and November 2008 ranged from a low of $3.27 to a high of $12.37 per tcf (DOE, 2010).

105 There are a number of concerns over potential Qatari supplies. In 2005 Qatar announced a five-year moratorium on new gas projects to allow time for studies to be done on the behaviour of the North Field. It has subsequently suggested that this will be extended to 2015 (Von Kluechtzner, 2010). However, there have been recent rumours that the North Field is in trouble as a result of over-production. Therefore future plans for Qatari expansion after the end of the moratorium must be in doubt. Such concerns are reinforced because there is no agreement with Iran – the South Pars Field is on the Iranian side of the border – over unification of the North Field and South Pars Field. As Qatar produces gas, it is producing Iranian gas as well as its own. This is likely to be a source of future conflict between the two countries, especially as Iran is struggling to develop its side of the field, in part as a result of sanctions.

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