NATURAL GAS MARKET REVIEW

2006

Towards a Global Gas Market

INTERNATIONAL ENERGY AGENCY

OECD

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ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

The OECD is a unique forum where the governments of thirty democracies work together to address the economic, social and environmental challenges of globalisation. The OECD is also at the forefront of efforts to understand and to help governments respond to new developments and concerns, such as corporate governance, the information economy and the challenges of an ageing population. The Organisation provides a setting where governments can compare policy experiences, seek answers to common problems, identify good practice and work to co-ordinate domestic and international policies.

The OECD member countries are: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The European Commission takes part in the work of the OECD.

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FOREWORD

In the last decade, natural gas has grown to become a truly global energy source. Increasingly, gas is seen as an essential fuel to meet the three important pillars on which IEA member countries' energy policies are built: energy security, environmental sustainability, and economic competitiveness and growth.

While OECD countries account for a little over half of global gas consumption, they sit atop less than 10% of the world's gas resources. Despite this, gas demand continues to grow, both in the OECD and non-OECD countries. The majority of reserves are located in Russia, Iran and Qatar. The level of international gas trade will grow and price signals from previously isolated markets will start to be transmitted around the globe.

Recognising the importance of these developments, IEA ministers at their May 2005 meeting highlighted that the IEA's focus on energy security meant more than just oil security and also embraced gas and electricity issues. Subsequently, our member governments asked us to augment our work on medium-term analysis of gas markets. This Natural Gas Market Review is our response to that call. The review is designed to be global in scope, covering not just IEA regions, but also developments in major non-member countries. The review considers not just traditional pipeline gas and liquefied natural gas (LNG) markets, but also looks at the impact of the rapid expansion in LNG trade. We review events over the last four years, and look forward to 2010, when supply developments that are currently underway should come to fruition.

When we first planned this review less than twelve months ago, we could not have anticipated the series of events that have impacted the gas industry since. Hurricanes in the United States severely damaged gas and oil installations. Russian gas supplies to Europe were disrupted in early 2006. LNG supplies from a whole range of suppliers suffered from technical problems, and the largest LNG producer, Indonesia, had on-going difficulties in meeting contract shipments. The United Kingdom is still adjusting to its recently acquired status of a net gas importer; it also suffered high prices, particularly when its major gas storage was rendered inoperable by a fire. In Italy, the gas system was severely tested as supplies only just met record demand from the power sector.

Inevitably, these events have focussed attention on the gas sector from policy makers, other parts of the energy industry, the media and the general public. With that in mind, we have tried to make the review a useful and informative document for a range of audiences. We have widened its scope to include issues such as price formation and gas storage, which have important policy and market implications, but are complex and not always well understood.

These challenges will increase as the industry moves towards a global gas market, highlighting the importance of market design and, in particular, the regulatory reform currently underway in all IEA regions. One key feature of such reforms must be to encourage greater transparency. To play a meaningful role in the gas market, governments need access to clear information on its behaviour, from reserves and investment levels to gas flows and pricing. Consistent, timely data will reduce opportunities for exploitation of market power, help a more coherent diagnosis and treatment of problems, and assist in formation of a proactive energy policy.

This Natural Gas Market Review is seen as the first of a regular series on this subject. We look forward to receiving feedback from policy makers, regulators, industry, observers and the general public to enhance the usefulness of the next publication.

We also anticipate continued progress in the exchange of information with both producer and consumer countries as a way of improving understanding of the evolving gas market, and thus leading to better-informed decision making.

This book is published under my authority as executive director of the International Energy Agency.

Claude Mandil,
Executive Director

ACKNOWLEDGEMENTS

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The main authors of the review are Daniel Simmons, Helmer Horlings and Ian Cronshaw. Significant contributions were made by Sylvie Cornot-Gandolphe, Dagmar Graczyk, Brett Jacobs, Isabel Murray, François Nguyen, Julia Reinaud, Jonathan Sinton, Olga Sorokina and Ulrik Stridbaek. Virginia Prystay provided valuable assistance.

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EXECUTIVE SUMMARY

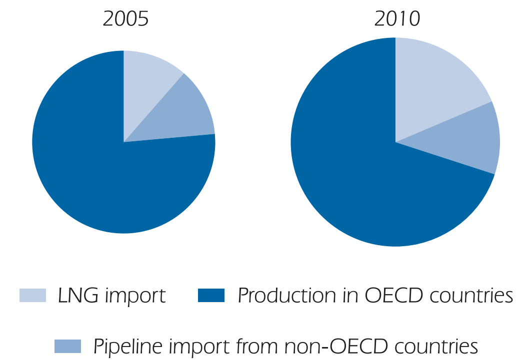
Strong demand growth to 2010, driven by OECD countries power demand and developing countries.

Natural gas accounts for 21% of global energy supply, with slightly higher proportions in the relatively mature markets of North America and Europe. Rapid growth since 2000 is expected to moderate in the second half of the decade, but global demand is still expected to increase from 2.8 tcm in 2005 to 3.2 tcm in 2010. The main driver of this growth in OECD countries is power generation, whereas the growth of gas demand in other regions such as the Middle East, China and India is driven by other sectors as well. Despite current high prices, the vast majority of new power generation on line in the review period will be gas-fired. Should price levels persist, investment in gas-fired power generation is likely to level off after 2010.

OECD regions look to imports, as domestic production reaches a plateau and LNG gains importance.

The Middle East and former USSR countries hold 41% and 32% of global gas reserves respectively, whereas OECD countries together hold 9%. Total OECD countries' gas production will be unchanged over the review period, with Norwegian and Australian production increasing as that from the United Kingdom declines and other countries reach a plateau. By 2010, gas produced in OECD countries and delivered via pipeline, will still account for the majority of OECD countries' gas use. However, as shown in Figure 1, by the end of the review period, 30% of imports will be supplied both via LNG and from non-OECD countries. Dependence on imports from non-OECD countries in 2010 will vary between regions, from less than 10% in North America to 48% in Europe and 63% for Asia-Pacific. LNG currently supplies less than 7% of global gas consumption, the vast majority of which go to the Japanese and Korean markets. However, LNG looks set to provide around 40% of the global supply growth between 2005 and 2010.

Figure 1 **OECD countries' import dependence grows**



Less than half of the necessary gas sector investment is currently committed.

For the period 2005-10, projects currently under construction in the gas sector amount to only about USD 210 billion with a further USD 300 billion planned and thus uncertain. This compares with the IEA's estimated requirement of around USD 520 billion for this period. Hence, there is a serious risk of under-investment unless it is assumed that all projects currently in the planning stage will proceed on time. Investment in LNG production, transport and related infrastructure appears strong, with most of this output destined for

OECD countries' markets. Meanwhile, pipeline investment looks significantly weaker relative to requirements, especially in non-OECD countries. Although several significant pipeline projects are coming to fruition, risks for pipeline investments crossing multiple frontiers are perceived to be growing. The most recent phase of gas projects is seeing higher costs, delays or postponements because of rising raw material costs and shortfalls in the availability of skilled labour.

Supply from Russia will remain essential, but there are concerns over investment.

Russia is currently the world's second largest gas market and the largest gas exporter; it also has the largest share of reserves. With no operational LNG capacity, Russia currently exports exclusively via pipelines to the Former Soviet Union countries and Europe. 80% of Russian exports to Europe transit through Ukraine. Russia has reliably delivered gas to Europe for several decades despite political turbulence and has committed to expand exports, including into North American and Asian markets via several new LNG export projects. Due to its vast reserves and the location of the gas fields in Russia, the country will be able to do so without affecting European deliveries assuming it mobilises the necessary capital and expertise in a timely manner. However, there is serious concern that the upstream and midstream investment necessary to meet existing export commitments is not being committed. Overall production from Russia's largest gas fields is declining, but there are a number of policy and investment options available, which can help maintain or enhance Russian gas production and, hence, exports. These include greater third-party access to pipeline networks; domestic prices more in line with European prices increased pipeline maintenance, more efficient domestic use and reduction of the large volume of gas which is currently produced but flared.

LNG production will double and flexibility will increase.

LNG will make up almost 20% of the OECD countries' gas supply by the end of the review period. The majority of gas sector investment has been focussed on developing LNG supplies, with production set to almost double between 2004 and 2010. In Japan and Korea, LNG will retain its central role but for the North American and European regions, LNG will become an essential supply source at the margin. Buyers and sellers are increasingly using the physical flexibility in the LNG chain to seek the markets with the highest returns, and are introducing more flexibility in their contracts. LNG projects are being built without traditional long-term contracts, a strong vote of confidence in this new role of LNG.

The Pacific remains key to the LNG market, but Atlantic markets will grow in influence.

Japan is the largest LNG importer in the world; Korea is the second largest and is growing at 10% per year. By the end of the review period, however, the Atlantic LNG market will grow to at least equal the Pacific market. Middle Eastern LNG exports, having similar distances to either market, will increasingly link the Pacific with the Atlantic, carrying price signals between them.

The increase in European gas imports will be met through both LNG and pipelines.

In the United Kingdom, there is a large amount of investment in infrastructure: two new LNG terminals are being built, capacity is being upgraded and pipeline import infrastructure is also being added.

Two-thirds of Spanish gas demand is met through LNG imports, making it the third largest LNG market after Korea. The Spanish market is growing at around 15% per year with two terminal expansions and one new terminal to be completed in 2006.

In Italy, there is only one LNG import terminal currently in operation, but there are plans for many more, plus the ramping up of the new Green-stream pipeline. Each of these countries makes extensive use of gas in power generation. The Northern European Gas Pipeline is designed to link Russia directly to Germany via a pipeline under the Baltic Sea.

The increase in North American imports will be met through LNG alone.

Canada is currently the largest gas exporter to the United States, the world's largest gas consumer; it accounts for 15% of United States' demand. Both the United States and Canada have seen a large increase in gas drilling activity as gas prices have risen in recent years, but this has not resulted in a corresponding production response. Flattening North American gas production combined with rising demand will see LNG becoming more important in North American gas supply. By the end of the review period, LNG will supply up to 9% of the North American market through a number of new import terminals. The North American market will increasingly be linked to world markets and *vice versa*.

Qatar has emerged as a major gas exporter, but Indonesia is slipping.

Qatar has emerged as the world's largest LNG producer in 2006 and its share is rising rapidly. It will supply 25% to 30% of the world LNG market in 2010 as a result of successful efforts to attract overseas investment in its abundant reserves. Qatar is positioned to sell its large volumes into both Atlantic and Pacific markets, further linking these gas markets (as well as 20 bcm per year to neighbouring countries).

Meanwhile, the opposite is true for Indonesia which currently supplies a quarter of Korean and Japanese gas demand and was the world's largest LNG producer before 2006. A lack of investment has meant that existing LNG production is declining, resulting in lower deliveries to its buyers. Efforts to substitute domestic gas in the current oil dominated energy mix seem likely to reduce gas availability for exports. Algeria, currently OPEC's largest gas exporter, with 64 bcm in 2003, looks set to expand to 76 bcm by 2010. Australia has the potential to emerge in the top rank of LNG suppliers in that time frame.

China and India represent massive latent demand for gas at lower prices.

Chinese gas demand represents only 3% of its primary energy use and is mostly satisfied by domestic production. The government has ambitious plans to double gas use to 100 bcm by 2010, but the current high price environment has slowed construction of infrastructure necessary to provide this. LNG imports should commence with the inauguration of the first terminal in 2006, and a second will be added by 2009, but further expansions may be pushed back until after 2010.

Meanwhile, Indian gas demand is outpacing supply, resulting in shortfalls despite import terminals operating below capacity. Domestic gas-pricing reform will be needed to enable potential customers to secure imports and to encourage domestic gas production. Gas pipeline projects from Iran, Central Asia and Myanmar have shown little recent progress.

Prices remain influenced by oil even in markets where they are not directly linked to oil.

Prices are under strong upward pressure in a sellers' market, as demand grows but new supplies take longer to respond. In continental Europe and Asia, gas prices are still linked to oil prices through formulae that also serve to moderate volatility. This protects consumers but means that crises must be managed centrally, as there is no mechanism for demand-side response. In North America, under tight supply conditions, pricing links are observed between natural gas and a range of oil products. However, in North America and the United Kingdom, gas prices directly reflect the supply/demand balance. Prices can, therefore, be volatile, especially following supply disruptions, but this allows consumer participation to balance tight markets.

Storage has an important role in reducing volatility and providing reliable supplies.

Storage is central to reducing price volatility and to smoothing seasonal and other demand variations. Strategic gas storage may also have a role to play in ensuring supply reliability, but its costs and limitations are significantly higher than for oil storage, and it is, therefore, probably best used as part of a wider suite of options such as fuel switching and interruptible contracts. As with large oil storage, if a gas storage holds enough to supply an importing country for 30 days, this does not guarantee uninterrupted supplies for a month in the event of an import disruption.

Regulation is geared to promoting competition and investment.

A number of governments are changing or introducing policies to reflect the long-term investments needed in the gas industry, and these changes are having a marked impact on investment. The European Commission (EU Commission, or Commission) is stimulating competition between domestic gas suppliers, with important progress in the elimination of destination clauses on gas delivered to the EU and the implementation of the Second Gas Directive. In Japan, regulatory reform has resulted in strong competition between energy providers, while an independent LNG terminal was recently completed in Korea. Canada and the United States are both implementing regulation which allows for more gas exploration and production, and the United States has recently passed legislation to encourage LNG imports.

2005 and 2006: supply problems and rapid change.

Hurricanes reduced United States' gas production by around 10% over the last four months of 2005, and gas production had not fully recovered to pre-hurricane levels as of May 2006. Prices rose markedly in North America in response to this disruption – from already high levels – peaking late in 2005 and impacting industrial consumers particularly, before a mild winter saw demand weaken, and stocks built to more comfortable levels.

Interruptions to gas supplies from Russia transiting the Ukraine in early January 2006, and then a little later in the winter, due to very cold weather, have raised awareness of the importance of security of gas supply, including transit.

In the winter of 2005-06, North America, the United Kingdom and Italy have all seen extreme tightness in their gas markets, and Spanish, Japanese and Korean gas importers have been forced to pay record prices for spot cargoes.

While Japan and Korea remained by far the most important markets for LNG, global supply expanded rapidly in 2005 with increasing imports to Europe. However, a number of LNG plants experienced technical production problems, particularly at start up, which restricted supply to spot markets. These problems should ease over 2006.

Looking forward: towards a global gas market.

Gas prices rose alongside oil prices in all major markets in 2005 and 2006. This trend is expected to persist into the medium term. Although much investment is underway in the gas supply chain, especially LNG, concerns remain about the overall adequacy of investment. The lead time for new supplies to come on stream is such that pricing pressures look set to remain in the near to medium term. Although demand growth to 2010 is set to be strong, should existing price levels persist, this is likely to affect investment in plant due to come on line after the review period.

The gas market is changing, but it is still firmly based on the traditional regional markets. North America will import more LNG, Europe will increasingly see the impact of LNG on its pipeline businesses, and traditional Asian LNG markets will be exposed to global forces. Over the review period, LNG will increasingly be the glue binding the three OECD regional markets, resulting in a definite trend towards a global gas market.

POINT OF DEPARTURE

The Natural Gas Market Review 2006 presents insights into today's dynamic gas market, including recent events during 2005 and 2006, supply and demand, pricing, investment, LNG and gas for power generation, storage, gas-to-liquids (GTL), regulation and some individual countries. The authors recognise that recent attention to natural gas will attract readers with various backgrounds ranging from policy makers to industry experts, from regional consumers to global strategists, from energy specialists to the interested general public. Bearing in mind this diversity of readership, this Section has been included to provide the general fundamentals of the natural gas industry. Interested readers are also advised to benefit from earlier IEA publications.[1]

Three regions dominate natural gas trade

Natural gas is used around the world but the major areas of trade correspond to the OECD regions: North America, Europe and Asia-Pacific. Gas in these markets is used for residential and commercial needs, industrial heat and, increasingly, power production.

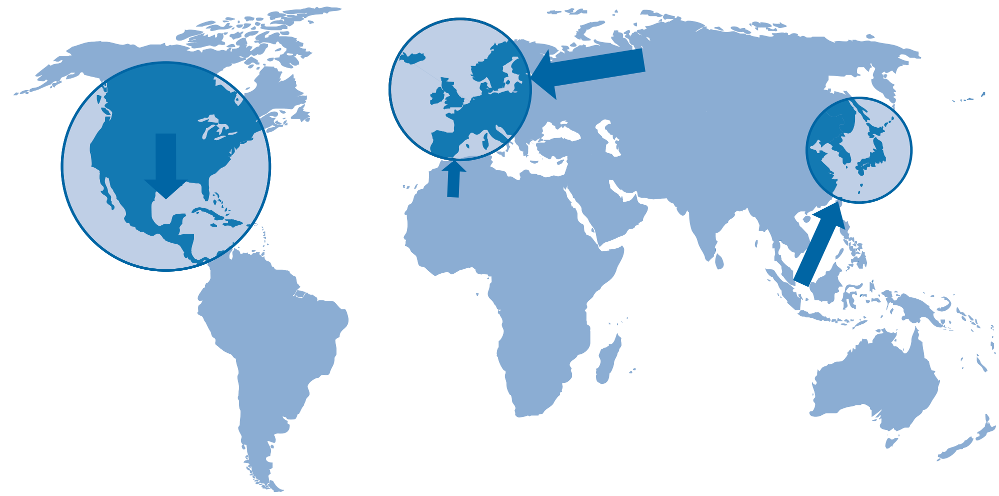
North America has been largely self-sufficient, with Canada being an important exporter of natural gas to the United States. Gas prices in this market are set through gas-to-gas competition, meaning that in times of over supply prices will be low and in times of tight supply prices will be high. At times of high prices it is up to the consumer whether to continue paying, to reduce gas use or switch to other fuels. Gas accounts for nearly 24% of primary energy supply in this region.

Europe is partly self-sufficient and relies for more than 40% of its gas supplies on imports, mainly from the former Soviet Union countries and Algeria. Generally, the gas price in Europe is directly linked to the price of oil. Hence, gas prices will go up when the price of oil rises, not necessarily when the supply of gas is tight. Customers are thus less likely to adjust their demand since they do not receive timely or necessarily relevant price signals. On the other hand, suppliers are less able to manipulate prices. Certain countries in Europe are now moving towards the North American system although at various speeds, with the United Kingdom as a prime example.

The Asian gas industry has developed since the 1970s, as liquefied natural gas (LNG) became available as a means to import gas from Malaysia, Brunei, Indonesia, Australia and the Middle East. Japan and Korea are almost entirely dependent on LNG imports, and gas is a relatively smaller proportion of the total energy supply of Asia-Pacific (14%). Gas use within this area varies from country to country, as does pricing. Gas prices are linked to oil in Japan and Korea, but with a formula that differs from that of European gas users. In Australia and New Zealand, prices are set by gas-on-gas competition.

1. See, for example: *Security of Supply in Open Markets* (IEA 2004), *Resources to Reserves* (IEA 2005), *Flexibility in Natural Gas Supply and Demand* (IEA 2002) and *Natural Gas Information* 2005 (IEA 2005).

Figure 2 ***Traditional OECD countries' gas markets***



Gas is transported through pipelines and as LNG

There are two principal ways of transporting gas from the well-head to the burner tip: through pipelines or in the form of LNG. Both are expensive and require long construction times; therefore, a considerable period is needed to pay back the initial investment. Pipelines are more cost-effective over short distances. They do, however, tie the consumer to the supplier which creates a negotiating position which sometimes favours the supplier and sometimes the consumer, but always involves a certain amount of trust. Customers can, however, be reasonably sure that gas keeps flowing as long as they pay the right prices and the gas resource is adequate, since it is generally in all parties' interests to keep an expensive pipeline fully utilised.

Liquefied natural gas is natural gas that has been cooled down to -161 °C to make it liquid. This is done in a liquefaction train, a series of process operations from gas to LNG. Often a liquefaction plant starts with one or two trains. Once these trains have proven successful, both technically and commercially, more trains can be added at a lower marginal cost (brownfield expansion) if the resources are sufficient. After liquefaction, the gas is transported in specially-designed ships. At the point of arrival, the gas is returned to its normal gaseous state in a re-gasification terminal.

High capital costs associated with LNG production and transport have encouraged a business model based on long-term take-or-pay purchase obligations, agreed well in advance of plant construction. While still the rule, this model is beginning to be modified. LNG has been essential for the development of gas use in Japan and Korea and its use is now growing in the rest of the OECD countries.

Since it is relatively easy to change the destination of LNG ships, it is easier for LNG to end up in the market which offers the highest price, even when it was originally contracted to another market. Pipelines do not offer the same flexibility. The cost of production of LNG is now low enough for it to be competitive in most parts of the world. A few liquefaction plants in the world have now started to supply all three markets described above. Competition for the few uncontracted ships (spot cargoes) is on a global scale. Since LNG is the marginal supplier in some markets, it means that the three previously separated markets are beginning to be exposed to each other.

Gas consumption

As noted above, natural gas is used mostly by three sectors: residential and commercial consumers; industrial consumers and power companies.

The residential and commercial sector uses gas for heating, cooking, hot water and, to a limited extent, cooling. Since heating uses most gas, demand is heavily reliant on weather conditions, but otherwise relatively predictable. In some countries, gas consumption in this sector can be several times higher in winter than in summer. Residential users often have no or little alternative and are, therefore, called captive. Since residential consumers are only periodically confronted with their energy bill, it is difficult for them to react to short-term price changes. They can and do, however, react to continuing periods of high prices, e.g., by adjusting their energy efficiency.

Industrial consumers use gas for heating, melting, as feedstock, or sometimes to drive their own small power plants. Gas demand is relatively predictable and depends on process parameters. Some industrial users can change to other fuels; all can optimise their energy efficiency. It is not uncommon that industrial consumers, which are directly exposed to high energy prices, reduce gas demand by decreasing or stopping the production of their goods or by moving production to locations where gas is cheaper. In other markets, industrial consumers are sheltered from high prices because other macroeconomic variables (e.g., employment) are considered more important.

Apart from gas, the power sector uses coal, uranium, oil and hydro to produce electricity. Gas has a variety of benefits, however, the price of gas can be a disadvantage to power companies. This disadvantage can be offset if electricity prices are high enough; the difference between gas and electricity prices is called the spark spread. Gas and electricity markets are, therefore, increasingly interacting, which is particularly noticeable in liberalised markets.

Units

Different regions have traditionally developed different units to measure quantities, prices and energy flows. In this report, the following units are used as much as possible: for volumes – *billion cubic meters* (bcm); for prices – *United States Dollars* (USD); for energy content – *Million British thermal units* (MBtu). Wherever possible, alternative units are given in brackets.

RECENT EVENTS

United States' gas markets lost around 10% of gas supply in the last four months of 2005 and production is yet to fully recover. Prices rose rapidly and stayed high throughout the winter.

Interruptions of gas supplies from Russia in early 2006 have renewed the debate on gas security in Europe with particular focus on the dependence on Russia, Ukraine and Turkmenistan.

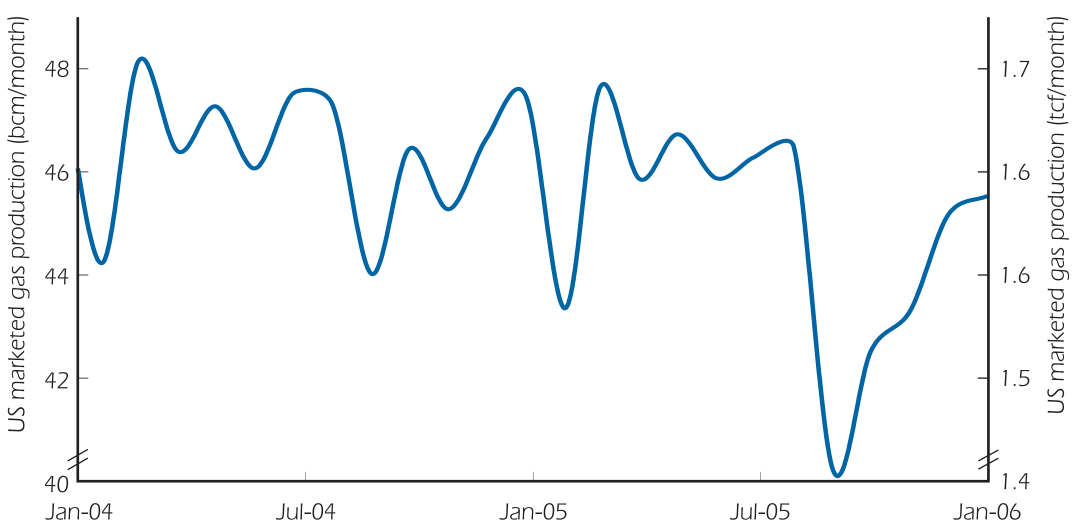
High gas prices in the United Kingdom and supply cutbacks in Italy in winter 2005-06, without a corresponding supply-side response, have highlighted failings in the European gas market.

Hurricanes in North America

On 29 August 2005, Katrina, a major hurricane, hit the United States' Gulf of Mexico, causing severe damage to New Orleans and to a substantial part of United States' offshore oil and gas production. In following months, hurricanes Rita and Wilma caused further damage to onshore and offshore oil and gas production and processing. Under normal conditions, about 0.3 bcm/d (10 bcf/d) is produced from the United States' offshore Gulf coast; this represents 17% of the total United States' domestic consumption.

Figure 3 shows the decrease in total United States-marketed natural gas production. In the first three months after the hurricanes a total of 12% less was marketed compared to normal[2] production, so 2005 gas output

Figure 3 **United States' production profile showing loss as a result of 2005 hurricanes**



Source: EIA

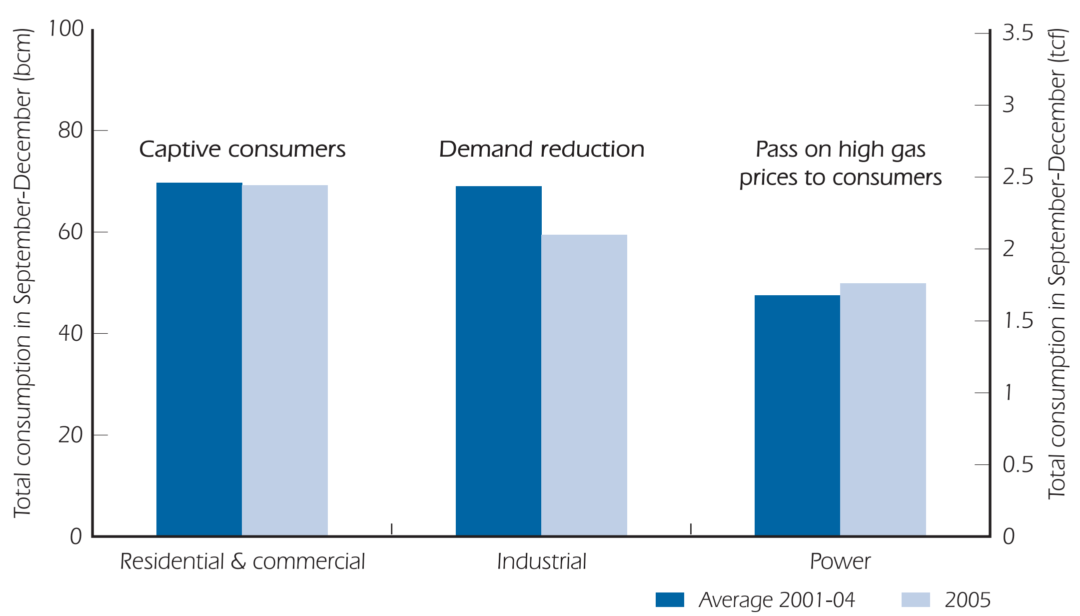
2. Taken as the average of the same months in the period 2001-04.

was down by nearly 3%. In spring 2006, production had yet to completely recover. The five United States' LNG import terminals operated only at about half of their capacity, because importers in other markets were prepared to pay even higher prices, and global availability was lower than expected.

Given the lack of supply, the market was mainly balanced by adjustments on the demand side. Residential and commercial consumers did not change their gas consumption since demand in this market segment is normally more temperature-sensitive than price-sensitive. However, industrial consumers used significantly less gas in the aftermath of the hurricanes. It is unknown to what extent this should be attributed to (temporary) disruption of operation, or to fuel switching. It is likely that at least some industrial consumers using natural gas as a feedstock stopped or shifted production. Feedstock costs are a major part of their total costs so this market is price sensitive. Demand figures from September to December support this view: whereas residential consumers used more gas than in previous years due to cold weather, demand from the industrial sector was still down by almost 11%.

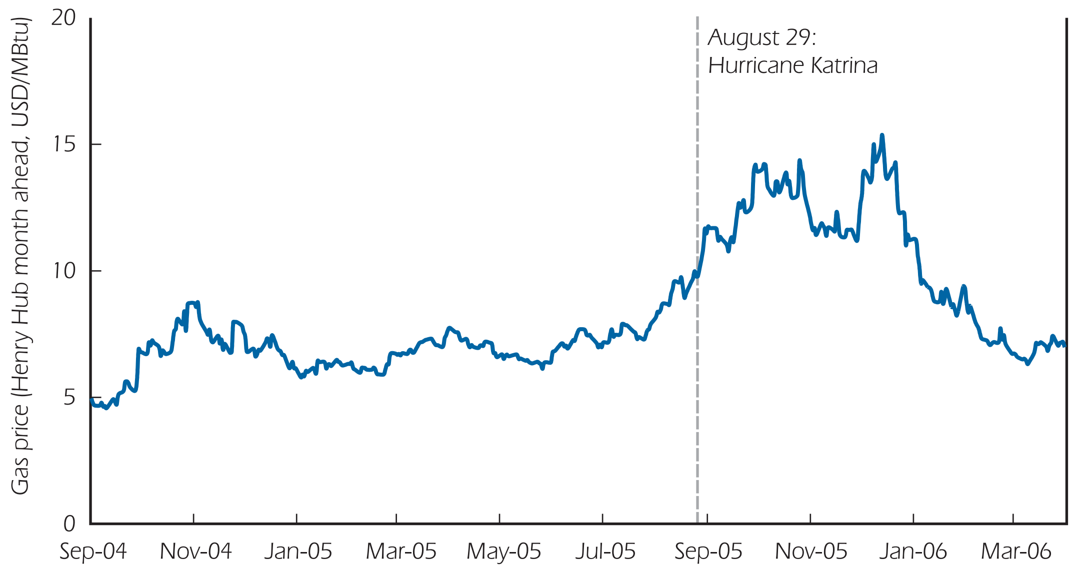
Interestingly, power producers appear to have consumed natural gas at levels around normal demand. It is likely that power producers have been able to pass on the higher fuel costs to their consumers, either through the rate base or through strong spark spreads.

Figure 4 **High natural gas prices cause demand reduction in the United States' industry**



Source: EIA, adaptation IEA

Figure 5 **Tight supply causes high prices in the United States' natural gas markets**



A notably mild winter, especially January 2006, allowed stocks to build to high levels, and prices moderated from highs of USD 15/MBtu to around USD 7-8/MBtu by spring 2006, well above the 2004 price of around USD 6/MBtu. On an oil equivalent basis, a price of USD 8/MBtu corresponds to around USD 50/bbl, well below corresponding crude prices of around USD 70/bbl.

Russia/Ukraine gas dispute

Russia/Gazprom supplied around 150 bcm to Western Europe in 2005 (over a quarter of gas demand), of which around 80% transited through Ukraine. On 1 January 2006, following a lengthy commercial dispute, Gazprom gas supplies were reduced markedly to Ukraine. This resulted in a reduction of deliveries to many Western European countries as well, for a period beginning early in the morning on 1 January and lasting for about 1.5 days. In total, about 100 mcm that were expected in OECD countries were not delivered. In addition, the Ukraine itself suffered a shortfall of 150 mcm.

In OECD Europe, drawdown of storage and voluntary fuel switching were able to make up for the shortfall relatively easily, because the duration of the interruption was short. The dispute and consequent interruptions did cause serious concerns over security of supply and gas dependence on Russia in many European countries. A number of measures were discussed in the aftermath of the dispute, including increased strategic gas stocks, diversification of the fuel mix (with higher dependence on coal

Figure 6 **Ukraine is a major transit country for EU gas supplies from Russia**

and nuclear being the most prominent options), diversification of gas supply by calling on other pipeline gas suppliers, increased fuel-switching capacities, and energy efficiency. Discussions also focussed on additional LNG terminals, including in Poland, Germany, the Netherlands and the Adriatic, or at least the acceleration of existing proposals.

On 4 January, price terms were agreed between Russia and the Ukraine, in a complex deal involving averaging prices with Central Asian suppliers. The deal seems weak and lacks transparency, with many issues remaining unresolved. In addition, it has been subject to criticism both inside and outside Ukraine. As of late April 2006, Ukraine is in the process of installing a new government, which could either favour the deal or be strongly opposed. Prices are set only to mid-2006 and need re-negotiation thereafter. Should the deal or re-negotiations collapse, the consequences for security of supply of countries relying on transit gas are not easy to predict, but further interruptions should not be discounted.

Ukrainian prices were at very low levels compared to those paid by Western European countries in 2005. Having said this, Gazprom is clearly prepared to use harsh tactics to enforce higher prices.

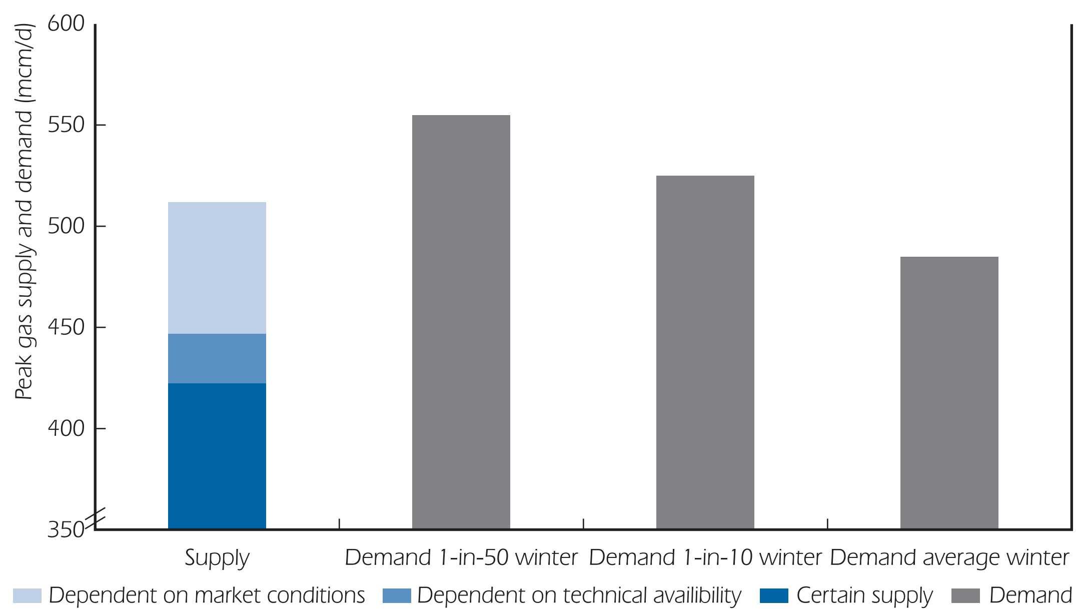
High prices in the United Kingdom

During much of the winter 2005-06, prices in the United Kingdom were above USD 10/MBtu, due to an exceptionally tight supply/demand balance. Price spikes even reached USD 30/MBtu in November 2005 and March 2006 (see Figure 8).

During 2005, the decline in United Kingdom's gas production accelerated and the country became more reliant on imports of natural gas. Imports to the United Kingdom are available through the Interconnector from Belgium (maximum capacity of 45.2 mcm/d), and in the form of LNG at the Isle of Grain terminal near London (13.5 mcm/d). Domestic production and storage are relatively certain sources of supply, although they are subject to normal technical availability (maintenance and small interruptions). Supply through the Interconnector is dependent on the prevailing price differentials, the availability of surplus gas on the European continent and the availability of capacity to supply Zeebrugge at the Belgian end of the Interconnector. Because of geographical factors, when the United Kingdom is suffering from cold snaps, the conditions on the continent are often even more severe, reducing the chance of spare capacity and volumes on the continent. Supply of LNG is dependent on global LNG availability and global price differentials.

The tightness in the United Kingdom's market is illustrated in Figure 7, which shows the maximum peak supply in 2005-06 for the United Kingdom and maximum peak demand for various winter types assuming no demand response to prices (a '1-in-50 winter' being a winter so severe that it statistically occurs only once every 50 years). Even during average winter

Figure 7 **2005-06: tight gas supply in the United Kingdom**

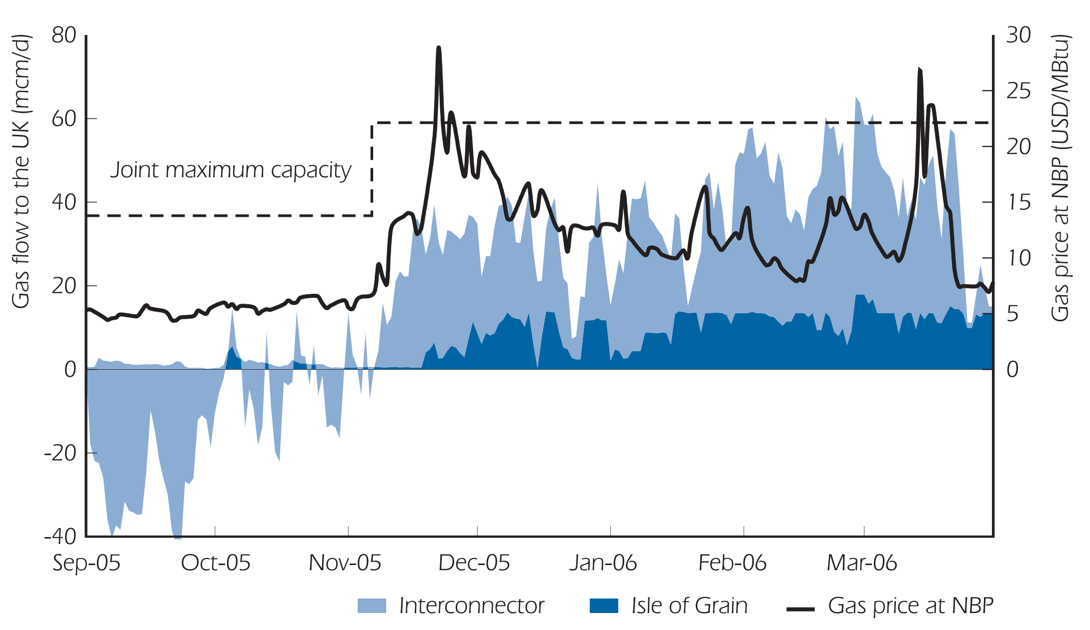


Source: National Grid Winter Outlook 2005-06 weather, some imports are needed. Winter weather was average-to-mild in the first half of the winter, so no serious supply disruptions occurred. Later in the winter, there was a brief cold snap which coincided with a fire at the United Kingdom's main storage facility (which had been considered certain supply). This caused National Grid to issue an emergency warning and prices spiked for a few days.

Concerns were raised in the United Kingdom as to why import capacity was not fully used despite the high gas price (see Figure 8). From November till the end of March, a net import of 5.2 bcm into the United Kingdom was realised, whereas over the same period 8.7 bcm would have been technically possible. From December 2005, Ofgem, the British regulator, has been very strict in applying the use-it-or-lose-it principle for capacity at the Grain LNG terminal, and Figure 8 shows that from mid-January 2006 the capacity at the terminal has been almost fully utilised. The same Figure shows that the Interconnector, on the other hand, has only rarely been used at maximum capacity, despite high price differentials, which caused the United Kingdom's government to file a complaint with the European Commission on the functioning of markets on the continent.

In the future, the United Kingdom import demand will rise steadily. A number of additional supply projects is anticipated in the coming years to meet this need. The Balgzand Bacton Pipeline (BBL) connecting the Netherlands with the United Kingdom

Figure 8 Import capacity under-utilised during United Kingdom's price hikes



Source: National Grid and IUK Ltd.

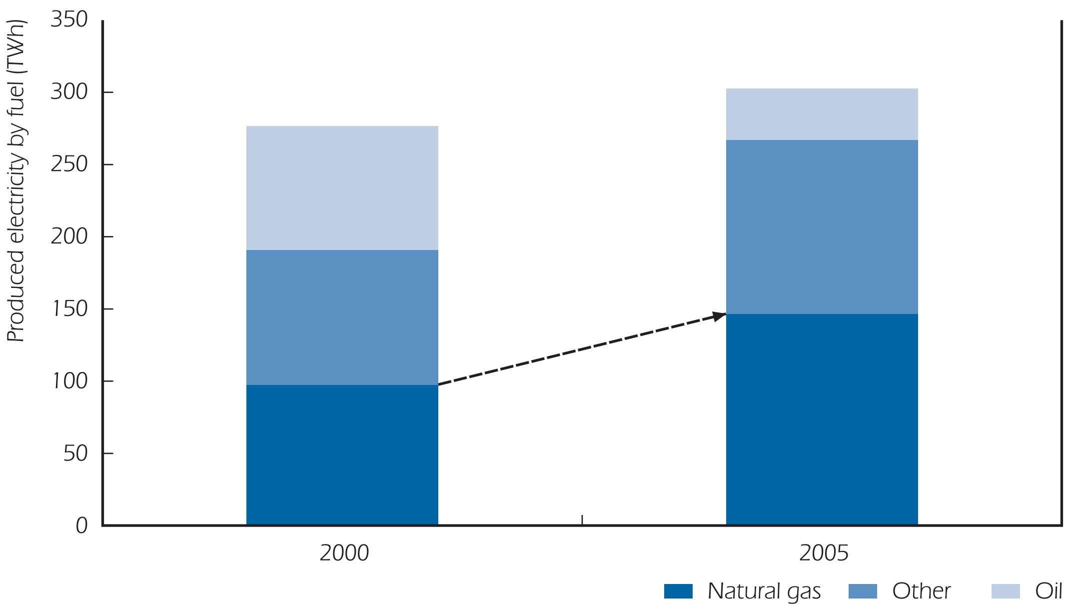
is due on stream in December 2006, capable of supplying an additional 44 mcm/d. It is unclear whether the total capacity can be used immediately due to possible capacity constraints in the Dutch grid, which is currently being de-bottlenecked, and the (non)availability of surplus gas on the continent.

The existing Interconnector is due to be expanded with an additional 19.1 mcm/d by December 2006 (regarding flow towards the United Kingdom). In 2007, new major infrastructure coming on stream should include the Langeled pipeline from Norway (74 mcm/d), and LNG capacity expansion at the Isle of Grain (adding 23 mcm/d) and two new terminals at Milford Haven (25 + 16 mcm/d). LNG in particular should provide some much needed diversity of supply. Having this infrastructure is important but does not necessarily guarantee ample supply, as more supply is dependent on market conditions.

Supply tightness in Italy

Italy has suffered severe natural gas supply shortages in the winter of 2005-06 as a result of the combination of unusually cold weather and an extraordinarily high demand of gas for power generation. This in its turn was a result of the start-up of a large amount of gas-fired power generation and strong electricity export. Annual natural gas demand in Italy is around 90 bcm with an expected growth rate of 3-5% per year. 15% of gas supply is produced domestically and the rest is

Figure 9 **Italy increases gas-fired power generation**



Source: Italian Ministry of Productive Activities (2005 provisional data) imported from Northern Europe, Russia, Libya and Algeria. One LNG import terminal is operating. Import is around 250 mcm/d, plus domestic production of 30 mcm/d.

Following a cold November and December and higher use of gas-fired power, demand was running as high as 400 mcm/d. Italy has storage capacity of about 12.7 bcm (working volume)[3] of which 5.1 bcm are considered strategic. During the course of January, storage use was able to provide 100-140 mcm/d, meeting around 30% of national demand. By the end of January 2006, more than two-thirds of storage had been depleted, and deliverability had begun to drop. To address this situation, a first set of government measures was adopted in early January, including maximisation of imports, interruptible supply contracts, fuel switching, improving energy efficiency, both by decree and by a call on customers. A special law was issued to enable certain electricity producers to use fuel oils different from those that the environmental law would normally allow. Further measures were implemented in February, including further relaxation of environmental standards. On 22 March the emergency situation was ended. By that time, 1.2 bcm of strategic stocks had been used.

Mention needs to be made of the role of Russian supplies in this situation. Russian deliveries were lower than expected throughout January and February, mainly due to higher off-take in Russia and Ukraine. ENI reports that Russian imports of 74 mcm/d had been requested over the winter. Average requested but not delivered Russian gas was around 5 mcm/d or a little over 1% of domestic demand. In February, up to 12 mcm/d had been requested but not delivered. The total amount not delivered was around 190 mcm. Notwithstanding these shortfalls, loss of Russian gas contributed but clearly was not the main reason for Italian gas market difficulties.

The Italian situation underlines the barriers to free movement of gas in Europe, given that a number of large gas-consuming countries in the region retained comfortable levels of gas stocks and supplies throughout this period. Besides, market signals should have either lessened the incentive for power producers to generate electricity from gas in times of scarcity, or higher gas prices should have resulted in lower demand in other sectors.

Additional gas-fired power generation is due on line in 2006 and the Italian government is aiming at enhancing gas stocks for the next winter. It also expects to increase domestic production and to speed up the development of infrastructure projects (new LNG terminals, interconnectors and expanding capacity of existing pipelines, such as fully utilising the capacity of the Green-stream pipeline from Libya in 2006).

3. See Storage Section for explanation of general storage characterisitcs.

GLOBAL SUPPLY AND DEMAND

As domestic production stabilises and demand grows, European and North American dependence on non-OECD countries for gas supplies will grow by 10% in the next five years.

Global gas consumption has been rising by 2.6% per year since 2000, whereas international gas trade has been rising by 5.2% and this trend will continue.

Approximately three-quarters of the world's gas reserves are in the Middle East and the countries of the Former Soviet Union. LNG is of increasing importance to get this gas to world markets.

Reserves and production

Global proven gas reserves were estimated at 180 tcm at the beginning of 2005. They represent 64 years of current gas production.[4] In energy equivalence, gas reserves are approximately equal to oil reserves (162 Gtoe). Since 2000, gas reserves have increased by 15%. The bulk of the increase is coming from the Middle East, where reserves of the largest non-associated gas deposit worldwide – the South Pars/North Field, which straddles Iranian and Qatari waters – were revised upward.

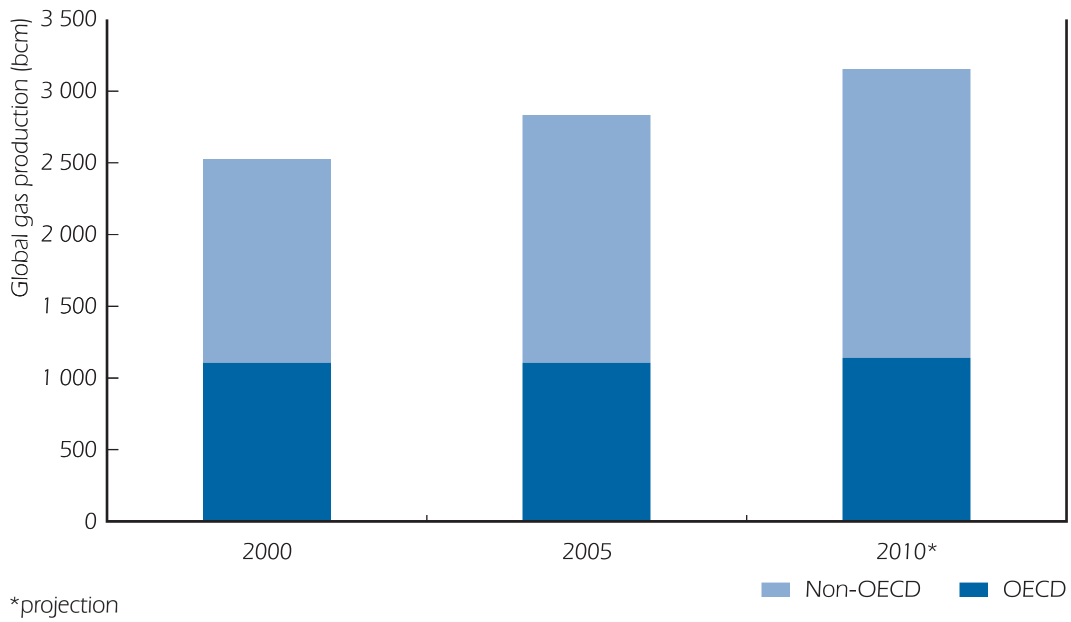
Although better distributed than oil reserves, gas reserves are Nevertheless, concentrated mainly in two regions, the Middle East and the Former Soviet Union countries, which account for 41% and 32% respectively of global gas reserves. Three countries, Russia, Iran and Qatar, hold 57% of total reserves. OECD countries account for only 9% of global gas reserves and these are being depleted at a high rate. The OECD countries' reserves correspond to only 14 times current annual production rates. In practical terms, this means that the total OECD countries' gas production cannot be sustained at current levels for much longer and, in some countries, has already peaked.

Global gas production amounted to 2.8 tcm in 2005, an increase of 2.6% per year since 2000. Most of the increase is coming from Australia, Asia, OECD Europe (Norway), the Middle East and the Transition Economies (Russia, Kazakhstan, Turkmenistan). In the next five years, global gas production is expected to rise by 2.4% per year to 3.2 tcm. The same regions are expected to be responsible for most of the increase. At the same time, OECD countries overall will account for 34% of global gas production, down from 44% in 2000.

In North America, high gas prices are spurring intense exploration and development activities and the number of producing wells in the United States has increased by 35% over the past five years. However, between 2000 and 2004, gas production was up only by 0.3%. 2005 saw a slight increase in Canadian and Mexican production of around 1.7% as compared to 2004, but United States' production

4. R/P ratios here merely serve as a means to indicate that global gas reserves are abundant but that OECD countries' gas reserves are less so. The reader should keep in mind that both production rates and reserves change over time. R/P ratios in North America have always been low and yet North America has been able to maintain a high production rate for decades. The North American market model stimulates exploration as reserves decline.

Figure 10 **OECD countries' gas production reaches plateau, production comes from non-OECD countries**



Source: IEA data

in 2005 was down due to the hurricanes (see the Recent Events Section) and it is difficult to say whether production would have otherwise risen. Higher prices are enabling the profitable exploration of unconventional gas, such as tight gas and coal bed methane (CBM). Increasingly, it will be these sources and later also Alaskan gas that will make up North American production. These prices also make North America an attractive market for LNG.

Some four-fifths of OECD Europe's indigenous gas production is sourced from the United Kingdom, Norway and the Netherlands. Gas production in Norway has increased by 60% in the first half of this decade and it is expected to continue growing substantially towards 2010. The decline in the United Kingdom's production offsets this growth and the net effect will be that by 2010 Europe's gas production will be back at the 2000 level. The Dutch government has announced a cap of 425 bcm over the period 2006-15 on production from the Groningen field, but the effect of this measure will only be visible around 2010, when the field will not be able to make up for the declining production of the smaller Dutch gas fields. Overall demand growth and flat production mean that the region will be increasingly dependent on imports in the form of LNG and piped gas from North Africa, Russia and other regions.

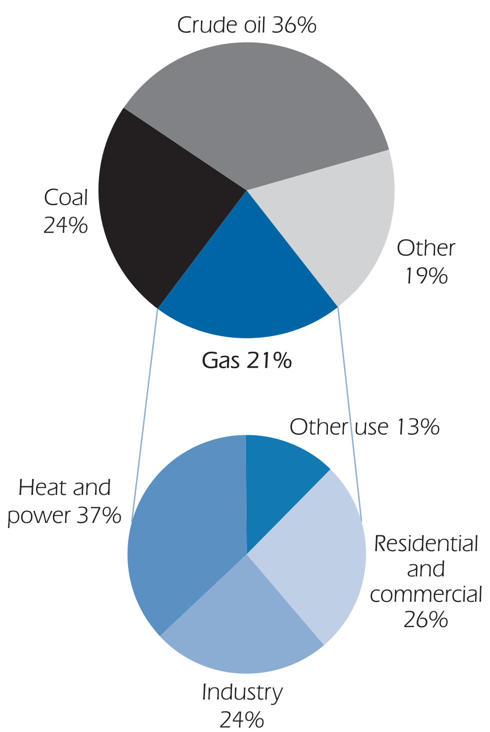
A surge in Australian production is expected to drive gas production growth in OECD Asia-Pacific, however, this region will still be importing almost two-thirds of its gas from other regions in the form of LNG by 2010.

Gas demand

Natural gas provides 21% of world primary energy supply. In North America and Europe, gas accounts for 23.5% and 23% respectively. In OECD Pacific, gas constitutes 14% of the total primary energy supply. The largest proportion is consumed by the heat and power sector.

Global demand for gas rose by 2.6% per year over the past five years, the bulk of the increase was in non-OECD countries. Total OECD countries' consumption rose by 0.9% per year. Provisional CEDIGAZ data shows that 2005 saw double-digit growth figures in Turkey (27.2%), Spain (20.9%), China (17.7%), Pakistan (11.3%) and India (11.0%). These countries together make up 6% of global gas consumption.

Figure 11 **Gas is an important global fuel* in key sectors, 2004**



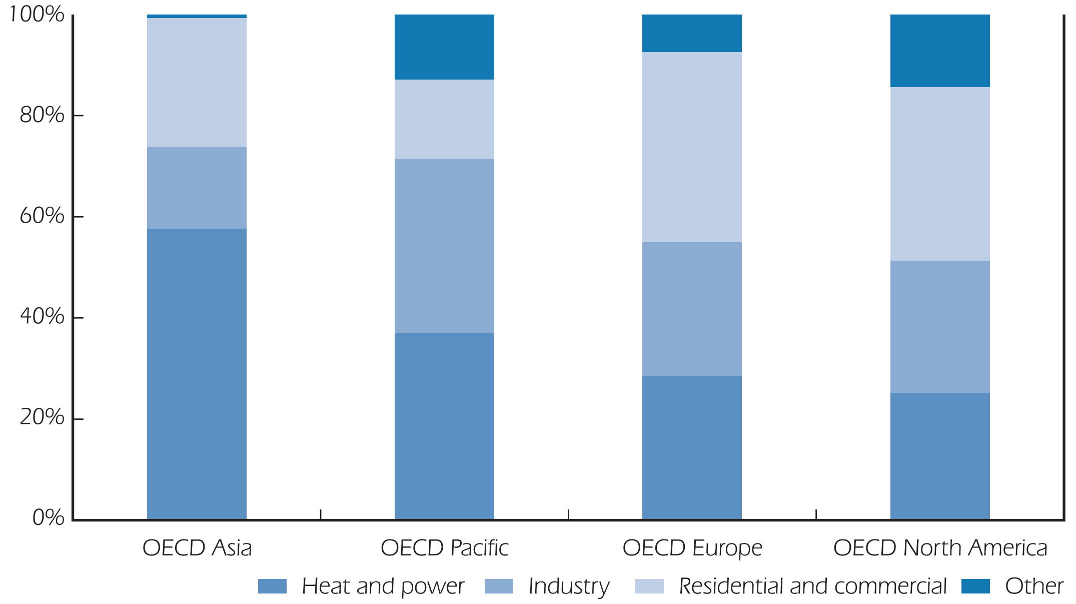
*Includes use as feedstock

Source: IEA data

Global gas demand by the power sector rose by 4.1% per year, making up more than 60% of the total demand growth. At this moment it is uncertain to what extent gas prices will influence gas demand in the power sector. As following Sections of the review will argue, gas demand in the power sector is relatively sensitive to the gas price due to availability of input fuel alternatives. In other sectors, gas consumers are less able to substitute gas for other fuels and demand reduction means either not heating houses and offices (in the residential and commercial sector), or decreasing production rates (in the industrial sector). However, the share of gas-fired plants in the power generation portfolio has risen and will continue to do so for the next few years, as will be explained in the Gas for Power Generation Section. This means that it is increasingly difficult to choose alternative generation as a short-term reaction to high gas prices and high gas prices, can in many instances be passed on to consumers via the electricity bill.

Gas demand in the industrial sector is affected by high gas prices and the effect has been especially clear after the hurricanes in 2005 when prices rose quickly, which caused at least temporary demand destruction in the chemical industry in North America. The effect is also observed in Europe, for example, in the United Kingdom and the Netherlands. It remains to be seen whether this effect is permanent

Figure 12 **Gas use varies in the OECD countries, 2004**



Source: IEA data

or temporary. This trend in reduced industrial gas consumption in OECD areas is unlikely to reduce global gas demand, since generally industrial consumption is shifted to another location.

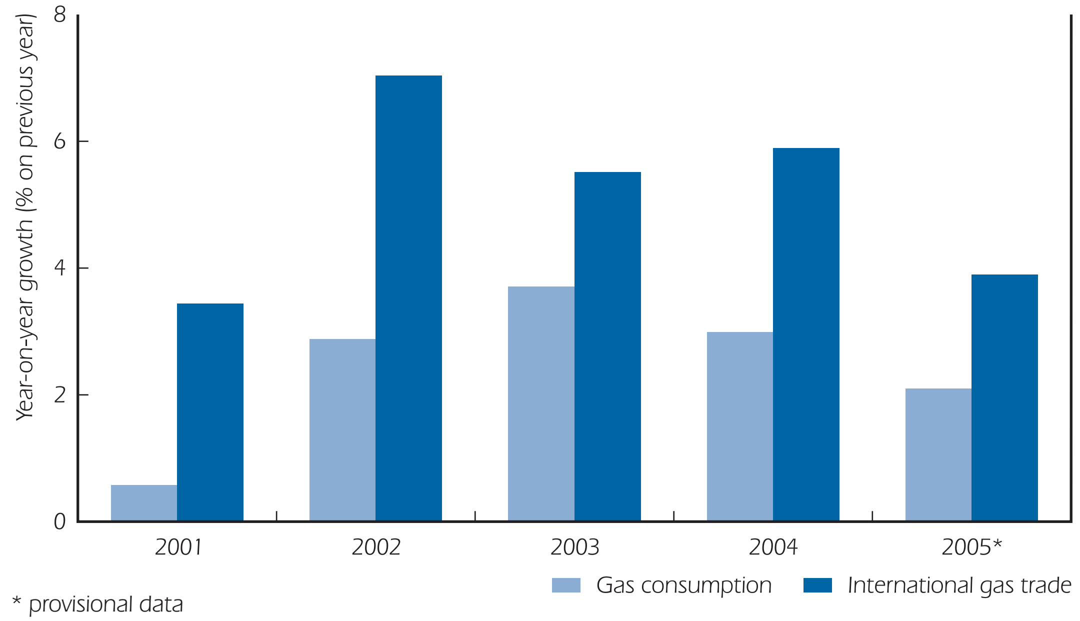
By 2010, global gas demand is projected to reach 3.2 tcm, an increase of 2.4% per year during the period 2004-10. All regions in the world are expected to record significant growth rates. The power sector is forecast to account for 55% of this increase. In OECD countries, the expected growth in gas demand by the power sector is even larger: 66% of the total increase between 2003 and 2010. Other sectors of the OECD countries' gas market (residential/commercial, industry) are already well developed and in several countries have reached saturation.

International trade

International gas trade increased by 4.7% to 825 bcm in 2005, of which 22% was accounted for by LNG. This figure reflects all cross-border flows, including both inter- and intra-regional trade. Compared to the increase in global gas consumption, this growth rate is all the more remarkable. Figure 13 gives an illustration of this phenomenon, which is a clear sign of the growing internationalisation of natural gas trade as the distances between centres of production and consumption increase.

International pipeline flows grew by 3.4% in 2005. The largest exporter remains Russia with 193 bcm exported in 2004 and close to 200 bcm in 2005, mainly to Europe and the Former Soviet Union countries.

Figure 13 **International gas trade grows faster than gas consumption**



Source: IEA and CEDIGAZ

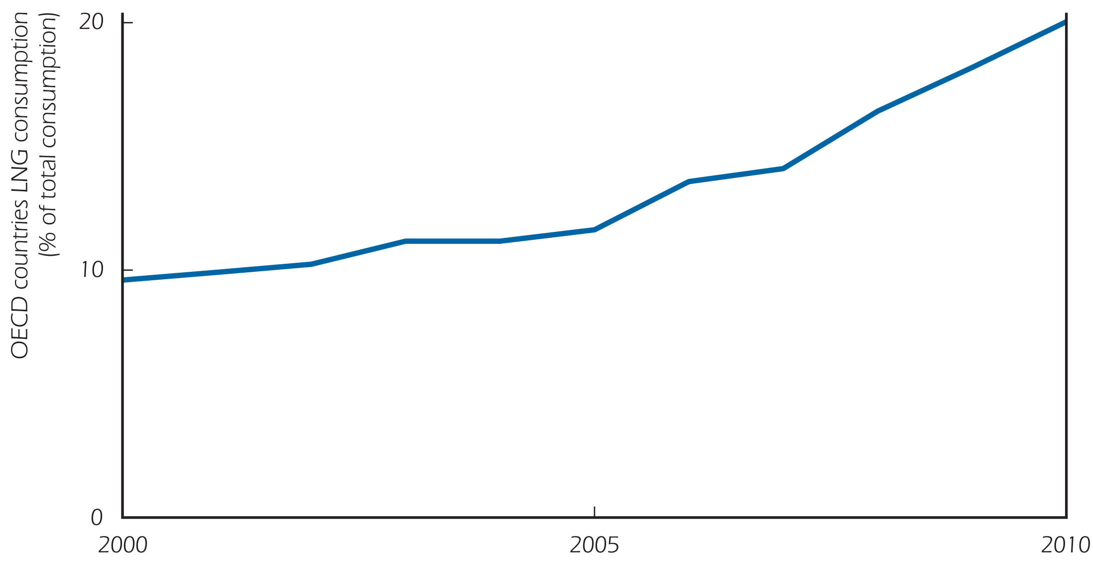
Canada is the second largest gas exporter; it exports slightly more than 100 bcm per year to the United States. It is worthwhile to note that gas trade is developing in almost all regions of the world – in particular in Asia and Latin America, although the gas transportation networks in these regions are relatively immature.

LNG trade continued its sustained growth in 2005 and reached 192 bcm,[5] with a rise of 7% compared to the previous year. OECD countries dominate LNG import; they account for 93% of total volumes, Japan alone takes 44%. Apart from Australia and a small quantity in the United States, all LNG is produced in non-OECD countries.

As explained in the LNG Section, the importance of LNG will increase in OECD Europe and North America, as domestic production cannot keep up with demand and there is an increasing drive to diversify the gas supply portfolio. In the next five years, the share of LNG in the OECD countries' gas consumption will double, exposing OECD countries more and more to gas supply from non-OECD countries. North America and Europe will have to rely for most of their LNG on Qatar, Nigeria, Trinidad and Tobago and North Africa. The real dependence, however, varies from country to country as can be seen in Figure 15. A conservative estimation of LNG trade is 300-350 bcm per year by 2010 up from 192 bcm in 2005. The figure will be higher if all production projects are realised as planned.

5. Provisional IEA data.

Figure 14 **OECD countries' LNG dependence to double in five years, IEA projection**



Between 2004 and 2010, it is expected that total inter-regional trade will increase by about 50% to 625 bcm. Most of the additional supply is expected to come from Russia, the Middle East, North Africa and LNG producers in Asia/Pacific. The highest growth in import volumes will occur in the European Union.

2005 raised policy questions in all OECD regions over reliance on gas imports. Asia saw lower than expected supplies from Indonesia, due to export policy changes. Europe is questioning the high reliance on gas delivered from Russia, especially after the dispute involving gas transiting Ukraine. The United States were not able to attract as much LNG as it had hoped for, despite high prices. Nevertheless, there is a clear trend that dependence on non-OECD countries will grow as is shown in Figure 16.

By 2010, European and North American dependence on non-OECD countries will have grown by 10%. By contrast, OECD Pacific will see dependence reduction due to increased production of Australian LNG.

In 2004, the overall spot LNG and short-term transactions were estimated at 20 bcm, accounting for 11% of total LNG flows (2.5% of total international gas trade). 2005 saw several examples of re-routed cargoes originally purchased under long-term contracts, showing that traders are increasingly using the flexibility which the LNG chain has to offer. Although it is too early to speak of a global gas market, the various regions of the world are certainly starting to interact. This means that events in one region have direct (through availability of gas), or indirect (through price) impacts on other regions.

Figure 15 **Dependence on LNG varies heavily among OECD countries, 2005**

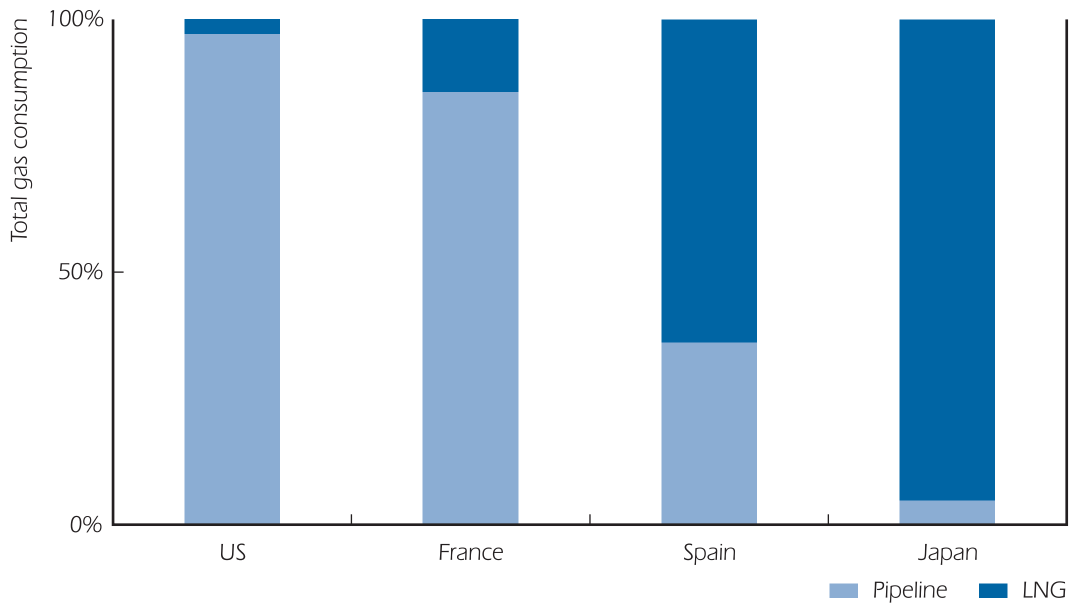
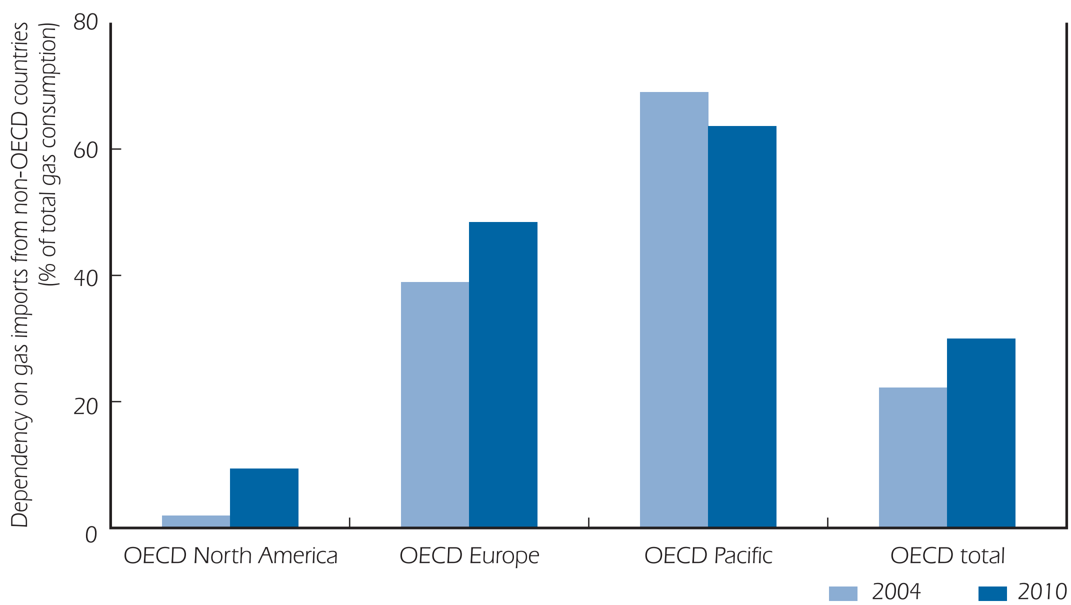


Figure 16 **Growing dependence on non-OECD countries, IEA projection**



GAS FOR POWER GENERATION

Around 30% of all power plant capacity across OECD regions uses natural gas as its primary fuel. 78% of new capacity built between 2000 and 2010 will be gas-fired, despite high gas prices.

Gas-fired power plants are well suited to generate peak and intermediate-load electricity for technical and financial reasons and can function as back-up for intermittent renewable generation.

Electricity demand on its own is very volatile and as more gas-fired capacity is added, demand for gas will be more volatile as well.

Share of gas-fired power generation

Natural gas can be used in various power generation technologies. Traditionally it was burned to create steam to drive a steam turbine, similar to other fossil fuels like coal and oil. Alternatively, natural gas can be used to fuel a gas turbine, either as a stand alone open-cycle gas turbine (OCGT) or in connection with a steam turbine driven by the exhausts from the gas turbine to form a combined-cycle gas turbine (CCGT). The development of gas turbines and CCGTs gained momentum with the rapid development of the gas turbine technology throughout the 1980s, and from 1990 CCGTs were added in many countries in large numbers. Modern CCGTs are now approaching generating efficiencies of up to 60%.

Much of the current investment in new power generation capacity in OECD member countries is in CCGTs to be used as base load or as flexible supply for the hours with higher demand. OCGTs are being built to meet peak load or as reserves for unforeseen incidents. Gas-fired power generation capacity is increasing as a share of total installed capacity in North America and Europe.

In OECD North America, 241 GW of new power generation capacity was added since 2000 or is under construction to come on line before 2010. 93% of this capacity is natural gas-fired. In OECD Asia and Pacific, 52 GW of new capacity was added since 2000; 26% of this capacity is gas-fired. In OECD Europe, 86 GW was added since 2000 and 70% of this capacity is gas-fired. About one third of the installed gas-fired generation capacity in the three OECD regions is able to use an alternative fuel. The added capacities reported here do not include extensions and upgrading of existing plants which have been significant in some OECD member countries, particularly for nuclear power plants. For example, in the United States, nuclear power plants were upgraded with 11 GW extra power capacity since 2000.

Additional plants are planned to be commissioned before 2010 but are still not under construction and are thus still uncertain. Some planned plants will not be built but the short construction time for CCGTs, on the other hand, may allow other plants to be built before 2010 even if they are not currently planned. There are recent reports of more planned investment in coal-fired generation in several OECD member countries, partly as a response to increasing gas prices. To the extent these plans will be realised, it is unlikely that it is possible to commission new coal-fired plants before the end of 2010 if they are not currently under construction.

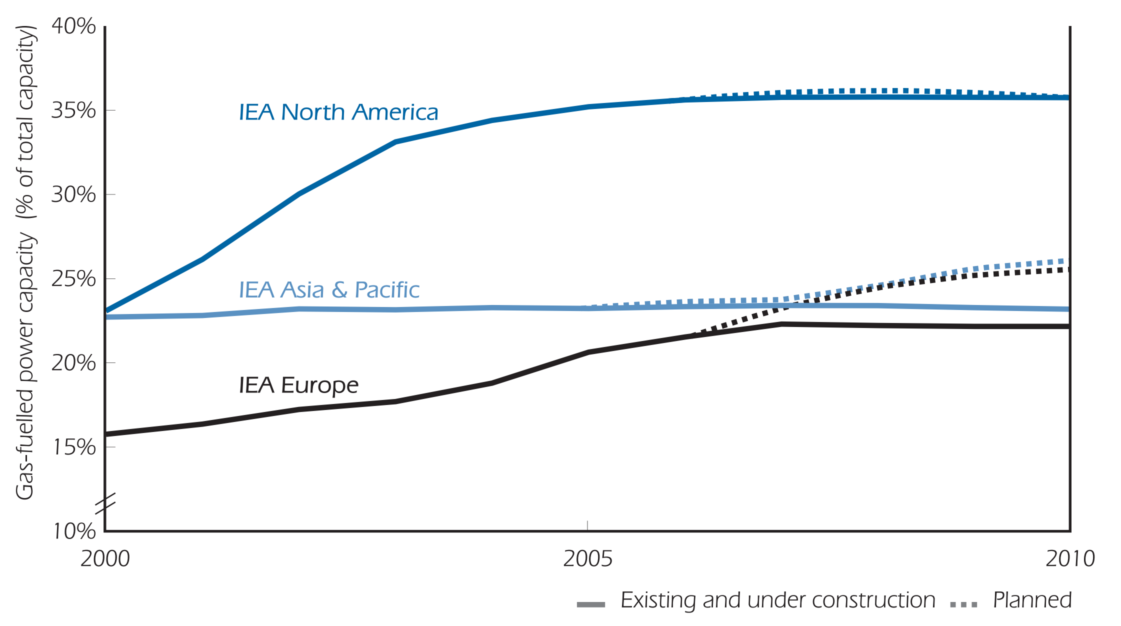
The share of gas-fired generation capacity in OECD North America seems to have reached a plateau at around 35%, and the shares in other OECD regions seem to continue to increase, coming from a lower level.

Japan has traditionally been at the forefront in the use of CCGTs already in the 1980s. Since then CCGTs have been a preferred technology for power generation in several countries. For example, in England and Wales, 26 GW was built from 1992 to 2004. From 2000 to 2005, 204 GW was built in the United States culminating with 57 GW in 2002 alone. From 2002 to 2005 10 GW was built in Spain and 12 GW in Italy with plans to add several GW in these two countries in the coming years.

Gas demand for power generation

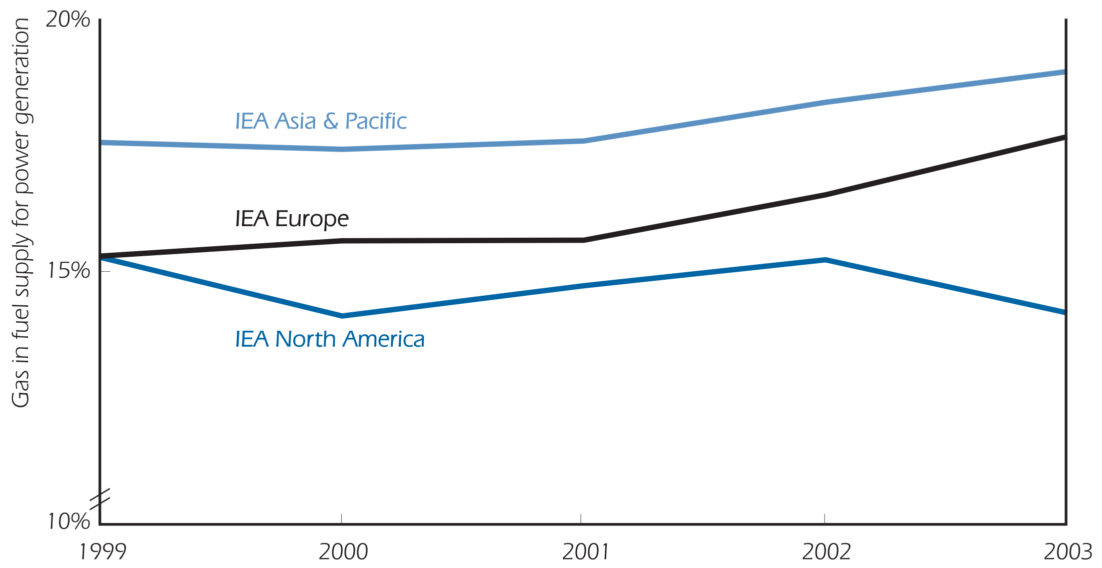
The gas demand for power generation as a share of total energy demand for power generation is generally lower than the shares of installed capacity. Gas-fired power generation capacity is used for base, mid- and peak load. Base load means that the plant is used day and night, all year round (high capacity factor). Peak-load generation means that the plant is used only at times of peak electricity

Figure 17 **Rising shares of natural gas-fuelled capacity**



Source: PLATTS and IEA

Figure 18 **Utilisation of gas for power varies per region**



Source: IEA

demand: this can be only a few hours per day. When used as mid- merit or peak-load, the capacity factors become lower than base-load plants. The thermal efficiency of gas-fired power generation is generally higher than other conventional energy technologies. This means that a high share of electricity is produced from gas, whereas the share of gas in primary energy supply to power plants is lower.

The share of gas demand for power generation as a share of total energy demand for power generation in OECD North America is substantially below the share of installed capacity and it varies significantly over time. The share varied around 15% during 1999-2003 even as the share of gas-fired capacity increased from 21% to 35% in the same period. Higher than anticipated gas prices caused gas-fired power generation to run at lower than expected capacity factors. Gas-fired generation in OECD North America is operating in liberalised gas and power markets where the use of the gas-fired generation is adjusted dynamically to the market price of natural gas and power. In OECD North America, the power sector used 2.5% less gas between 1998 and 2003, whilst the amount of power generated increased by 20% over the same period, indicating that the North American market is using gas more efficiently over time.

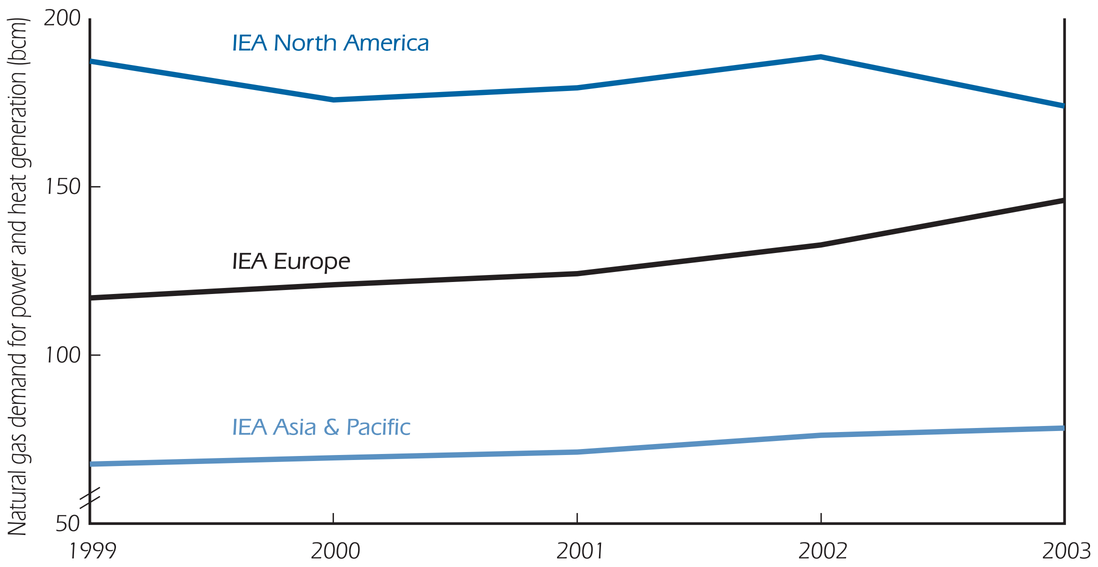
In OECD Asia-Pacific and in OECD Europe, the share of gas demand for power generation is only slightly lower than the share of gas-fired installed capacity. This indicates that gas-fired generation often is more frequently used as base load in these regions, and maybe that other conventional coal or nuclear base load plants are less utilised, an outcome which is not economically efficient. Long-term take-or-pay gas contracts are commonly used in these markets.This is likely to be an important driver for the high capacity utilisation.

Even if gas-fired generation capacity has continued to increase rapidly since the 1990s, the growth in gas demand by the power sector in OECD member countries has slowed down in the past five years (+3.2% per year on average over the period 1999-2003) compared with an increase of 6.7% per year in the 1990s. The impact of higher gas prices is already being felt. Nevertheless, by 2010, demand by the power sector in all OECD member countries is expected to reach about 575 bcm (476 Mtoe), compared with 422 bcm in 2003, corresponding to an annual increase of 4.5%. Gas use for power generation has become the driver for a second wave of gas demand, as the traditional gas market segments are approaching saturation in many OECD countries. There are, nevertheless, major differences among countries and regions and several challenges if the gas/electricity industry is to develop as expected.

The generation mix is still dominated by coal (46%). Most of the decrease in gas demand growth has occurred in the United States' market where competition between gas and coal power plants has been fierce in a rising gas price environment. In 2004, demand by the power sector increased again by 4%, certainly indicating the need to use gas-fired power plants at whatever price to cover peak electricity needs, notably summer air conditioning load. By 2010, gas demand by the power sector in OECD North America is expected to increase markedly. Much of the gas-fired power generation capacity expected to carry this demand has already been built, so the increased demand is mainly expected to materialise from higher capacity factors.

In OECD Europe, gas demand by the power sector in the period 1999-2003 registered strong growth: +5.7% per year on average, from 117 bcm to 146 bcm. Five countries are responsible for this increase since 2000: Italy, Turkey, Germany, Spain and France. Note that gas consumption by the power sector also includes the use of gas in CHP, which was particularly important in Germany and France. Gas demand by the power sector in the United Kingdom has stagnated, whereas it was the leading sector in the past decade, increasing by 30 bcm during the period 1990-2000. The high level of gas prices in the United Kingdom's market has lead to strong competition with other electricity options, including coal. A notable contrast exists between northwest and southern Europe. In the Mediterranean countries, electricity demand growth is driving a marked increase in gas-to-power. For instance, the addition of 10 CCGTs in 2004 doubled Spain's gas-fired capacity to around 8 400 MW and increased gas consumption by power generators by 66%. Gas-to-power in northern Europe has not shown the same dynamics, as a combination of lower demand growth and higher initial reserve margins held back new capacity additions. In the next five years, gas consumption by the power sector in OECD European countries is expected to reach 188 bcm. Most of the increase is expected to occur in southern Europe, in Spain, Italy and Turkey.

Figure 19 **Gas demand for power grows in Europe**



In OECD Pacific, gas demand by the power sector in the period 1999-2003 registered sustained growth: +3.9% per year, in line with that observed in the past decade. Gas now represents 20% of the electricity generation mix, compared with 17% in 1990. This increase is expected to continue during the decade. In 2010, gas consumption by the power sector could reach 108 bcm. Three-quarters of the increase in gas consumption by Korea is expected to be driven by new gas-fired power plants.

Competitive power markets

Electricity and gas sectors are liberalising to a certain extent in all OECD member countries, introducing competition at varying degrees and at various levels of the value chain. With the introduction of competition in the power generation segment of the value chain, costs can no longer automatically be passed on from investors and plant owners to final consumers. Owners of generation plants will only operate if their marginal costs are covered by the market price of electricity in any given hour, and invested capital and risk premiums will only be recovered if the market price is high enough to cover long-run marginal costs on average over the lifetime of the plant.

In this new setting, investors are forced to take all the real business risks into account when making investment decisions. Many business risks are fundamental in the sense that they arise from uncertainties such as future electricity demand, future prices of input fuels and future developments in generation technologies. These uncertainties have always represented real risks, but have previously been passed on directly to the consumer so they may appear to be new in the minds of investors. Liberalisation makes business risks more transparent. Other risks, such as policy factors, also have a significant impact on investment decisions, so policy makers and regulators have a key role to play to minimise these risks. A stable but credible policy framework and a stable but adaptable regulatory framework have an important impact on the appetite for investment.

When investors are forced to take the real business risks into account in their investment decisions, the view of the risk profiles associated with different technologies tends to change. Financial and operational flexibility tend to be assigned a higher value. Large upfront investments in capital-intensive technologies that represent large financial long-term commitments are less appreciated. Economies of scale are seen in a new light where large plants may lead to low unit costs but at the same time constitute a significant financial commitment, with a long lead time before positive cash flows.

In this market framework combined cycle gas turbines have some very beneficial features to offer in competition with alternative technologies. CCGT investment costs are low and predictable as the technology is very standardised. A CCGT can be built in 24 to 30 months and in incremental steps. An OCGT can be put on line very quickly (12-18 months) to meet an immediate demand and the steam turbine can be added later. This implies that gas-fired units can be added in a timely response to increased demand, which makes the economics of generation investments less vulnerable to the uncertainty of future developments in demand. CCGTs do not possess significant economies of scale so they can be built in relatively small units without greatly increasing the average unit cost. The largest share of the total generation costs from CCGTs depends on the price of gas, and the price of gas may put CCGTs out of the competitive merit order from time to time. The overall project is, however, not so vulnerable compared to other more capital-intensive technologies, as the financial commitment is more limited.

Other important factors favouring CCGTs in many markets include the comparable advantages in greenhouse gas emissions and the greater flexibility in siting. The significantly lower emission per MWh generated gives this technology an additional advantage compared to coal-fired plants. The fact that CCGTs are easier to locate close to load centres than large coal or nuclear plants also adds to the advantages. It is often more cost effective and easier to transport natural gas rather than electricity to load centres.

The EU Emission Trading Scheme should have a significant impact on the use of fossil fuels and could support the use of natural gas for both existing and new power plants. Emission permits were traded at more than USD 30/t (EUR 25/t) in the first quarter of 2006, partly as a result of high gas prices. The relatively high emission permit price illustrates the strong competition between coal and gas in a time of high gas prices and increasing focus on CO_2 emissions.

Box 1 **Will the EU Emission Trading Scheme influence investments in the power sector?**

In 2003, the European parliament approved the EU CO_2 emissions trading scheme (EU-ETS), a scheme whereby CO_2 emissions would be capped and traded within the EU area. The EU-ETS covers two trading periods: 2005/07 and 2008/12, the latter being the first commitment period of the Kyoto Protocol. In order to set the market size, EU member states each have to submit a National Allocation Plan (NAP) to the Commission, setting the level at which they would cap their own emissions. Operators of installations emitting fewer emissions than their target are able to sell allowances, while operators of installations emitting more must buy in order to be in compliance. The price of an allowance can rise and fall according to demand and supply, and settlement occurs each year. Any party who is not in compliance at the end of each year must buy at the closing price and suffer an additional penalty of USD 48 (EUR 40) per additional tonne of CO_2 in 2005/07 (rising to USD 120 per tonne from 2008).

The introduction of emission allowances has fundamentally altered operating costs in the power generation sector, and, therefore, investment decisions. The carbon allowance increases the variable costs for fossil-fuelled power plants since an emission allowance is needed for each unit of CO_2 produced. Coal-fired generation is more strongly affected than gas-fired generation because coal-fired power stations produce approximately twice the CO_2 of a gas-fired station per unit of power output. Since power generation is a large user of coal and gas and a large emitter of CO_2, the action of generators can be expected to have a strong influence on the prices of each as well as the price of electricity. The extent of the carbon costs and of their pass through to wholesale power prices have been subject to debate – partly because CO_2 allowances in the first round have been distributed mostly for free. Nevertheless, while generating companies are well versed in qualifying and managing these price risks, the future CO_2 market (post-Kyoto) presents more of a challenge. Because the investment profile of the generation sector is one of high upfront capital cost, the first few years of positive cashflows are critical to the viability of a project. Given that the planning and construction time of a coal plant is at least 7 years, this puts first positive cashflow after 2012, after the second phase of the EU-ETS.

Formulating a business strategy which takes into account the complex inter-relationship of prices within the power market is the fundamental business of an electricity generator. Having said this, the EU-ETS is not like other market. For example, Politicians do not decide the future demand/supply balance of coal or gas (or not to the same extent). Uncertainty about what happens after the second phase of the EU-ETS in 2013 is one of the major reasons that many generators have adopted a "wait and see" approach to high new power generation investment, a strategy which results in increased build of less risky gas plant with its lower CO_2 footprint.

The overall financial viability of more capital-intensive technologies, such as nuclear power plants and modern coal-fired plants, is highly dependent on the utilisation of the plant: the capacity factor. Whether the capacity factor is 75% or 85% has a strong impact on the average generation costs from a nuclear plant, so it is critical to the overall profitability that such capital-intensive technologies are operated whenever they are available. In electricity systems without competition, the reserve margins tend to be substantial, reflecting the fact that consumers rather than investors cover the risks. Plants financially suitable for base-load operation tend to constitute a large share of the total generation portfolio with the consequence that some base-load plants must be taken out of operation during hours with lower demand. CCGTs are particularly suitable to cover demand during these mid-load and peak-load hours. It is likely that a part of the current appreciation of CCGTs is a market response to adjust the portfolio of generation technologies. Such an adjustment explains the almost 100% concentration on CCGTs in newly- built generation capacity at the moment. The long term effects should not be overstated, however. After an adjustment where base-load plants come to constitute a more balanced share of the total portfolio of technologies, it is likely that new base-load plants will be built again. The most recent developments in the United States seem to confirm this scenario. In several markets with competition, the capacity factors of nuclear power plants and coal-fired stations have increased markedly, thereby improving the profitability of these plants.

A development towards higher shares of renewable technologies in some countries, particularly wind power, increases the need for flexible back-up and resources to cover intermittency. CCGTs are also meeting this new demand better than most other conventional alternatives, apart from large hydro plants with storage.

The financial and operational flexibility of CCGTs has important consequences for the demand for natural gas. CCGTs may be the choice of the day for new power generation capacity, but it will only result in gas demand if the price of electricity can justify the purchase of the gas. When the price of natural gas is at current (early 2006) levels, CCGTs are often the marginal technology, implying that they are only operated when other alternative base-load plants with lower marginal costs are not able to meet total demand. At lower gas prices, CCGTs may also be able to compete with coal-fired plants on marginal costs. For upstream gas demand, this implies that the presence of large shares of CCGTs is not a guarantee of corresponding shares of gas demand.

Experience shows that investors and asset owners are highly responsive to the signals they receive. With a credible, fair and competitive market, prices of both electricity and gas will reflect the fundamental balance of demand and supply. The profitability of an investment will rely on a good analysis of the fundamental market drivers as in other economic sectors, and investors will respond to the needs of the market. The response may be somewhat cyclical, which makes it important to integrate and interconnect markets across regional and country borders to form larger regional markets where cyclical swings can be somewhat balanced across the larger market. It is also crucial that market participants are sufficiently able to manage their risks through contracts, both long- and short-term, depending on their risk profiles and the market liquidity. In poorly working and uncompetitive markets, the signals are blurred and the responses are expected to be equally blurred, jeopardising efficiency and reliability. The establishment of well-functioning and sufficiently competitive markets in electricity and natural gas side by side is a critical challenge.

Investors are equally responsive to signals from the political and regulatory framework. Energy policy is determined in democratic political structures and it would thus not be credible to guarantee *status quo*. It is, on the other hand, clear that the more stability the political framework can offer over time, the less is added to the necessary risk premium from political uncertainty. Great uncertainty about the political commitment to market liberalisation, the willingness to intervene in the market, and changing policy measures (for example, in environment policy) will increase the required investment risk premium. This may favour CCGTs as the technology of choice but it may also postpone necessary investments altogether, critically jeopardising the reliability of electricity supply in the long-term.

Affordable and reliable electricity supply is critical to the prosperity of modern economies. Reliability of electricity supply depends on the performance of all segments of the value chain from upstream fuel supply to real-time operation of the electricity system. In real-time operation, there may not be sufficient flexibility in supply and demand to respond to sudden severe shortages, regardless of price signals reflecting this shortage. Real-time system operation remains a regulated activity with strict security parameters. Regarding security and reliability of supply concerns in most of the remaining parts of the value chain, there are no inherent reasons to doubt that competitive market players will respond to price signals to balance supply and demand. Prompt responses from market players in competitive markets tend to be a strong instrument in ensuring reliable electricity supply, which is at the same time produced at lowest cost. Effectively liberalising markets is thus a powerful policy option to ensure security of supply.

Upstream supply of natural gas is not the result of a perfectly competitive process since natural gas resources are relatively concentrated in a few countries. Investors in power generation capacity, including CCGTs, will analyse risks and financial consequences of possible upstream market changes and the potential likelihood for disruptions. Gas price increases and disruptions will have a severe impact on the profitability of the investment. There may be other broader economic consequences that go beyond the aggregate of the individual consequences for energy companies that may call for targeted policy measures. It is a challenge to design policy measures and determine appropriate government intervention carefully to ensure that it actually improves the quality of market responses without adding unjustified costs to the whole energy system. In liberalised electricity markets, experiences show that one of the most powerful instruments for consumers to oppose the market power of suppliers is the presence of a well-functioning, transparent and liquid wholesale market for electricity. It is likely that a liquid and competitive wholesale market for natural gas is also a powerful tool to counterbalance potential upstream market power in gas.

There are numerous policy challenges in establishing well-functioning gas and electricity markets to ensure affordable and reliable energy supply. One crucial feature to create resilience to short-term but severe disruptions is the importance of short-term price spikes to reflect the immediate need for balanced, cost-effective and significant responses. Price caps or other market interventions blur the signal and the necessary market response, such as reduced demand, increased supply or storage changes.

LIQUEFIED NATURAL GAS

The share of LNG in global gas demand will double to around 11% in 2010. By 2010, LNG will be an essential part of gas supply in each OECD region, making the difference between too little and just enough.

Australia and Norway will produce more LNG by 2010, but the main production sources for LNG will remain in non-OECD countries. Middle East LNG in particular will link Atlantic and Pacific markets, transmitting price signals between them.

The flexibility provided by the small but expanding spot LNG market is becoming more valuable to buyers and sellers. Increasingly, LNG will end up in places which provide the highest netback meaning that long-term contracts covering the entire chain are no longer absolutely essential.

Growth in the LNG industry

The rate of expansion in the LNG industry is spectacular. Over the past five years, trade flows have increased by 29% (+40 bcm), the liquefaction capacity by 48 bcm per year (+35.4 mtpa), the LNG fleet has grown by 75%. Major new LNG flows are connecting previously distinct regional markets and a global LNG market seems to be emerging. The traditional business model, with traditional long-term take-or-pay contracts, is starting to be supplemented, if not replaced, by a new one offering more flexible shorter-term contracts with in-built diversion rights, short-term market indices and optimisation of trade flows. 2005 saw LNG supply grow strongly, accentuating this trend.

The growth experienced in the past five years seems set to be surpassed by the growth in the next five years. Figure 20 gives an overview of the developments in liquefaction capacity. A 90% load factor is used in this graph to account for maintenance, logistics and small operation inefficiencies. Shortage of material and skilled manpower may slow down development, especially of the projects that are currently in the planning phase. Plants currently operating and under construction will account for 300 bcm of LNG production in 2010. Nevertheless, given the amount of projects in the engineering phase, production of at least 350 bcm of LNG by 2010 seems a conservative estimate with room for upwards revision. This would be a near doubling of the LNG produced in 2005 (192 bcm).

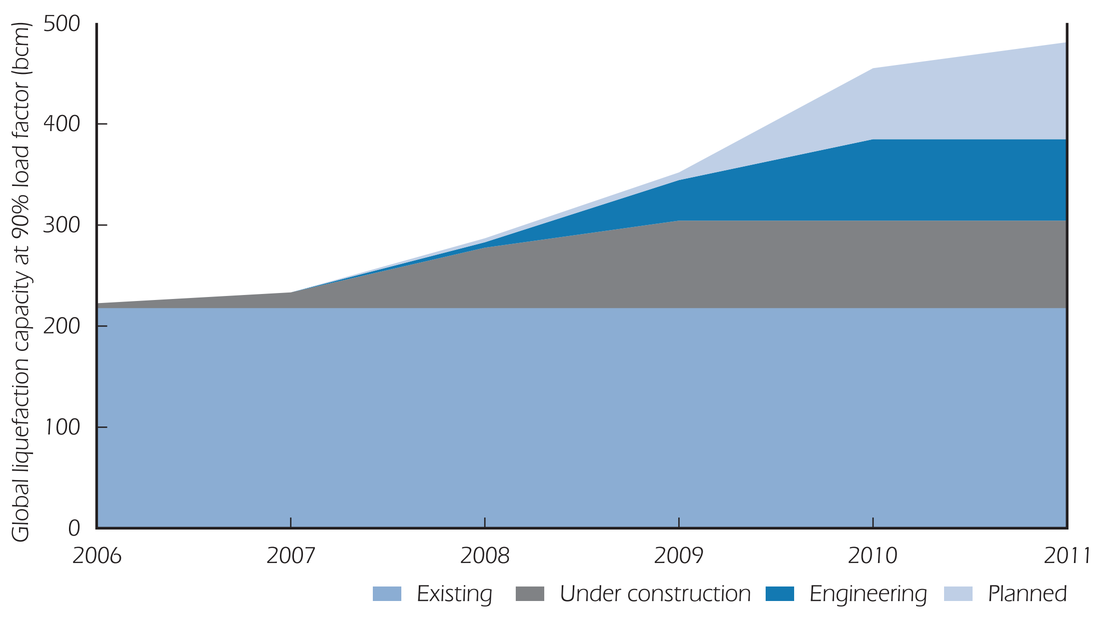
This impressive LNG growth is driven partly by the growing demand for natural gas, the flexibility of the LNG chain, the willingness of gas-resource owners and international oil companies (IOCs) to enter this booming market, and the opportunity for importing/exporting countries to diversify their natural gas supplies/demand. The substantial cost reductions achieved throughout the whole LNG chain due to economies of scale and increasing experience with the construction of LNG liquefaction plants have been important as well although currently shortages of labour and material are driving up costs in the industry. Recent increases in gas prices have meant transport costs are proportionally lower as compared to revenues. The emergence of Middle East LNG producers who can export to both Pacific and Atlantic markets is breaking down the regionalisation of the gas markets. Spain is an excellent example of supply diversification with LNG supplies from North Africa, the Middle East, Nigeria, Trinidad and Tobago and even Malaysia and Australia. On the supply side, Qatar has rapidly emerged as the leading producer, supplying the United States, India and various countries in Europe and Aisia. Hence, the strongly regional nature of gas trade is breaking down.

Demand in Asia-Pacific

To date, Asia-Pacific has dominated the LNG trade, with 119 bcm imported in 2005, accounting for about two-thirds of global LNG imports.

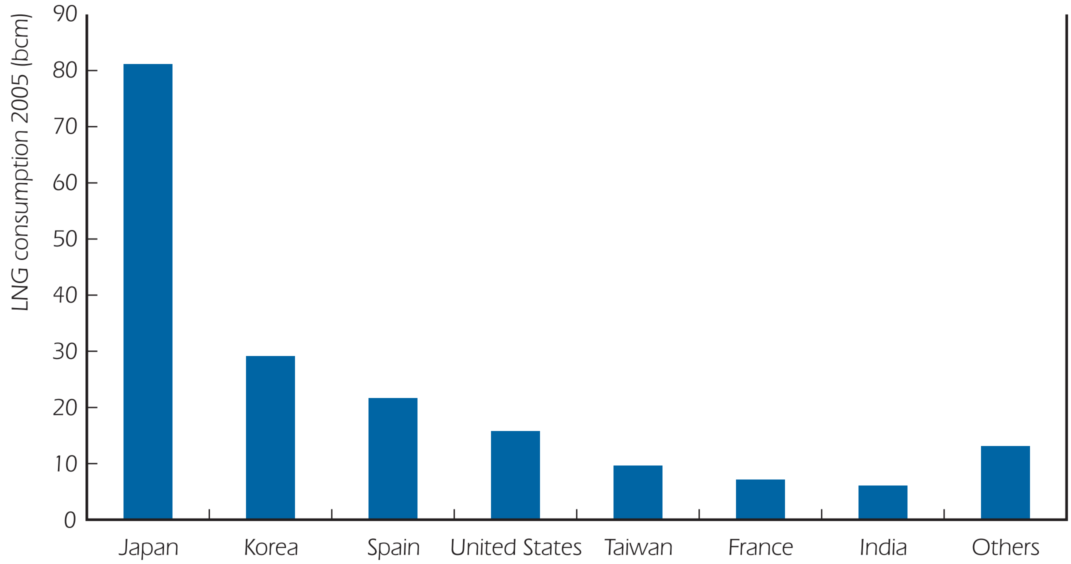
Japan is still the largest LNG market, with 81 bcm imported in 2005. However, its energy consumption growth is expected to slow because of population decline, change to the nation's industrial structure and the government's policy of reducing energy consumption to minimise CO_2 emissions. Expansion and use of nuclear capacity, however, may not develop as foreseen by the Japanese government, leaving more room for coal, gas and oil. Japan's approach to LNG purchasing is changing. De-regulation of the power

Figure 20 Spectacular growth in LNG supply



Source: IEA data, company statements

Figure 21 **Japan was the largest LNG consumer in 2005***



*provisional

Source: IEA data

and gas sectors has led to competition among Japanese energy suppliers. Hence, although Japanese buyers have almost always chosen to make their LNG purchases as a consortium, an increasing number of LNG buyers in Japan are now negotiating tailor-made deals with their suppliers (for instance, re-negotiation of Australian North West Shelf gas). They are requesting more flexibility in their purchases and shorter duration terms. Since in Japan natural gas is used primarily in power generation, gas demand will also be dependent on the availability of other sources for power generation.

South Korea, the world's second largest LNG importer, has a fast growing market, +10% per year on average over the past five years. The country is expected to sustain strong LNG import growth, driven by the development of its domestic gas network and power demand. LNG demand may intensify in the Pacific Basin, with India added to the list of LNG importers in the region and China expected to do soin mid-2006. Nevertheless, neither China nor India have been able or willing to contract substantial new volumes when prices were soaring in 2005-06.

Despite this positive outlook on LNG growth, it is unlikely that the region will maintain its high market share on a global basis, which could have important consequences on its bargaining power and price setting.

Demand in the Atlantic Basin

The Atlantic Basin is the fastest growing LNG region in the world, with both North America and Europe expecting to drastically increase LNG imports. So far, LNG has not played an important role in North American gas supply. LNG represented 2.5% of United States' gas supplies in 2005, but this is expected to change in the future. The gradual depletion of traditional sources of natural gas for the United States' market and the increasing demand and peaking prices call for increased LNG imports. Global LNG supply was tight in 2005 and despite high prices in North America the region has not been able to attract many spot cargoes due to fierce competition with Europe and Asia. Nevertheless, the growing supply of LNG in the coming years will see LNG imports in the United States rise. Around 2010, LNG will make up about 9% of North American gas demand.

Largely driven by demand from the power sector, LNG demand in the Mediterranean countries in Europe is set for rapid growth. With 41 bcm received in 2005, LNG only accounts for a small share of Europe's total gas supply (9%). However, this is concentrated in a few countries where it plays an essential role in the diversification of supply sources and the balancing of several southern European markets, including Spain (63.5% of total gas supply) and France (16.8%). Europe's anticipated import-dependence growth is stimulating producers and importers alike to build new infrastructure to bring additional gas to the market. LNG often emerges as a preferred option for producers to gain market share in mature power and gas markets, and is very likely to reinforce its position in Europe. Although gas-to-gas competition between the LNG and pipeline options will intensify, LNG will very likely take up an increasing share of the market.

Boosted by favourable regulatory changes in the United States (Hackberry decision) and Europe (possibility of exemption from third party access under the new Gas Directive), many regasification terminals are being built in the world. Others, however, are also not being built due to difficulties in contracting supplies and local opposition. The number of project proposals is an order of magnitude higher than the ones actually under construction. Nevertheless, the amount of regasification capacity in place seems to be more than enough to accommodate the LNG produced in the coming years. It is, however, good to keep in mind that the existence of an LNG terminal alone does not guarantee supply as is demonstrated by various LNG terminals worldwide working well below capacity as has been observed in the United States in the winter of 2005-06.

The Investment in the Gas Sector Section discusses briefly the investments in regasification terminals in the United States. North America has five importing LNG facilities, the fifth one, the Excelerate terminal, a floating LNG regasification vessel, successfully received its first cargo in March 2005. Six more terminals are under construction, including those on Mexico's North West coast, with proposals for many more (although only a few of these may be actually realised).

Existing combined capacity of European receiving terminals is now 76 bcm per year. With seven new re-gasification plants

Table 1 European LNG terminals under construction

Country	Name	Capacity (bcm per year)	Capacity (mtpa)	Completion
Belgium	Zeebrugge expansion	4.5	3.3	2007
France	Fos-Cavou	8.25	6.1	2007
Spain	Huelva expansion 2	3.9	2.9	2006
Spain	Barcelona expansion	4	2.9	Q1 2006
Spain	Mugardos El Ferral	3.6	2.6	Q1 2007
Spain	Sagunto	6.6	4.9	Q1 2006
United Kingdom	Grain expansion	10	7.4	2007/8
United Kingdom	Dragon LNG phase 1	6	4.4	2007
United Kingdom	South Hook phase 1	10.5	7.7	2007/8
Italy	Rovigo	8	5.9	2008?
Italy	Brindisi	8	5.9	2008?
Total		**73.35**	**53.9**	

Source: company websites, IEA data

under construction and four expansions, the total capacity will increase to at least 140 bcm per year in 2008. Several proposals for new terminals and expansions have been launched for the years thereafter in the Netherlands, the United Kingdom, Germany, Poland, Italy, Spain and Croatia.

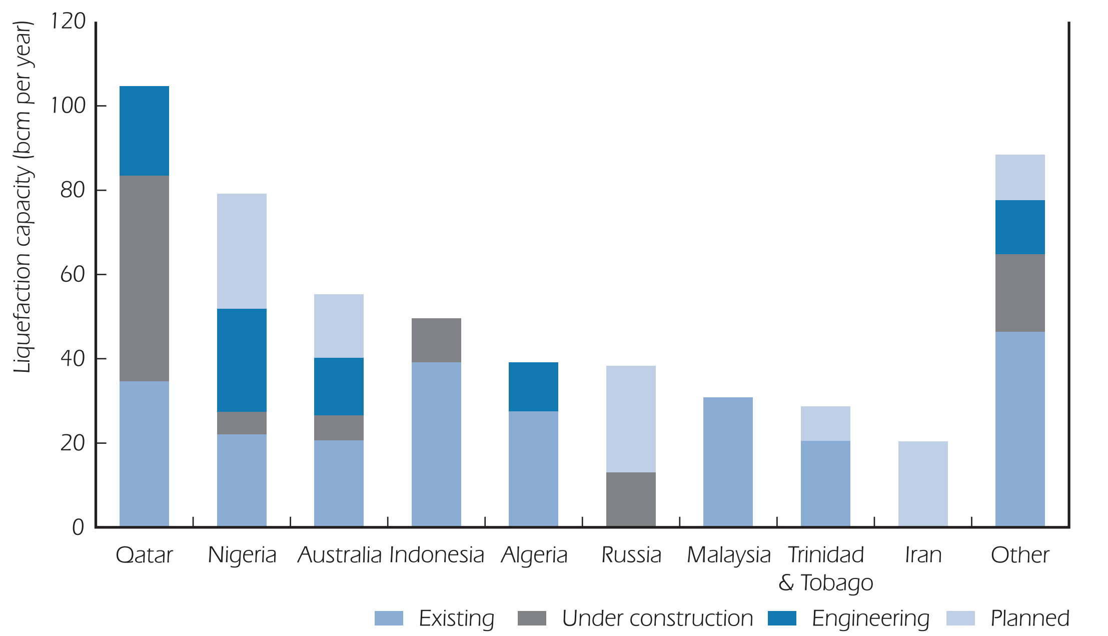
LNG supply

The current growth in global natural gas demand encourages national producers and international oil companies to invest in new production and liquefaction plants, since LNG allows stranded gas to reach a wide range of distant markets. Since the end of the 1990s, total world liquefaction capacity has been increasing rapidly with the commissioning of new plants/trains in Nigeria, Trinidad and Tobago, Qatar, Oman, Australia and, very recently, Egypt with two new greenfield plants. As of April 2006, the global liquefaction capacity was 178 mtpa (241 bcm per year) but capacity is rapidly expanding, as shown in Figure 20.

Future LNG production

Non-OECD Asia Pacific is still the dominant production region but this is set to change. Qatar is well on its way to produce over 100 bcm of LNG by 2010. In fact, Qatar is already the global leader in LNG output in 2006, since Indonesia's LNG facilities are not working at full capacity and this situation could deteriorate (see Section on Indonesia). Australia and Nigeria are also on their way to the top, but project status is not as advanced in these countries as in Qatar.

Figure 22 **New countries take the lead in LNG production**



Source: IEA data, company statements

Recent LNG outages

Although new LNG plants were commissioned recently, a number of unplanned outages at LNG plants and unusually long ramp-up periods at new production facilities created a squeeze in the LNG supply in the second half of 2005 and the start of 2006. Producers diverted excess LNG production from other trains to cover long-term contracts on trains that suffered from outages. This was one of the main factors that contributed to low deliveries of LNG to the United States, despite record high prices in North America.

- In Australia, a technical problem shut down Train 4 of North West Shelf for all of September 2005, resulting in production losses equivalent to several cargoes. The North West Shelf managed the shortfall and minimised disruption to LNG deliveries.

- In Nigeria, a leak in the main gas pipeline ignited a fire on 26 August 2005 and forced the shutdown of Trains 2 and 3, leaving Nigerian LNG operating at one-third of its capacity (a loss of seven cargoes).

- In Trinidad and Tobago, a long outage at Train 1 in August 2005 cost the United States' market several cargoes.

- In Egypt, while completed early, slow ramp-up of the new projects also resulted in losing some cargoes.

- Declining reserves at Indonesia's Arun LNG plant and the requirements to provide supply to local fertiliser plants have reduced LNG production and forced Pertamina to defer 9 cargoes for 2005. At Bontang, the diversion of gas to the fertiliser industry has caused the government to ask its Japanese buyers to cancel 41 LNG cargoes for 2005. More Indonesian cargoes are to be cancelled in 2006, possibly leading again to shortages in the spot LNG market.

It is very difficult to predict whether the large increase in LNG production coming on stream in the next half of the decade will take the heat off LNG demand. For a large part, LNG will be used to offset declining production from pipeline sources, meaning that it will not contribute to overall alleviation of supply tightness. The power market functions as a demand cushion, being able to absorb much more gas when the price of gas is competitive with other fuels, particularly in the United States where there is over-capacity in gas-fired power generation. One conclusion can be drawn: LNG will function more and more as an essential part of gas supply to a number of OECD countries, making the difference between enough and too little gas, thereby increasing the reliance on the Middle East, Russia, North Africa and Nigeria.

In Japan and Korea, the capacity of the 28 regasification terminals amounts to 290 bcm per year. In Japan, two terminals are under construction and two more are planned. In Korea, a fourth terminal, and the first privately built terminal in the country, was commissioned in July 2005 at Gwangyang.

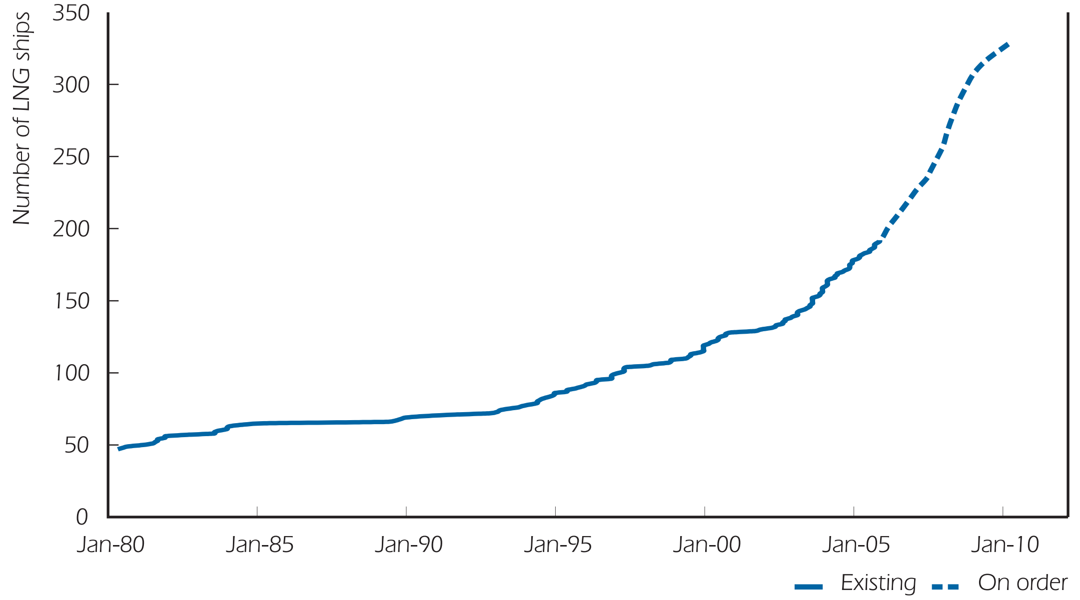
LNG fleet

The LNG fleet has grown exponentially over the past five years. This spectacular growth is explained by three main factors: 1) cost reduction for new ships, 2) the strategy of LNG exporting and importing companies which both integrate the full LNG chain, and 3) orders by independent companies which see the crucial value of the transportation link. This growth is expected to continue. At the beginning of 2010, the LNG fleet will number a minimum of 326 ships (see Figure 23). Qatar alone is expected to have a fleet of up to 90 vessels by 2010, among them the largest LNG carriers built so far (the QMax LNG carriers with a capacity of 265 000 m^3), which were recently ordered from South Korean shipyards.

Spot LNG market

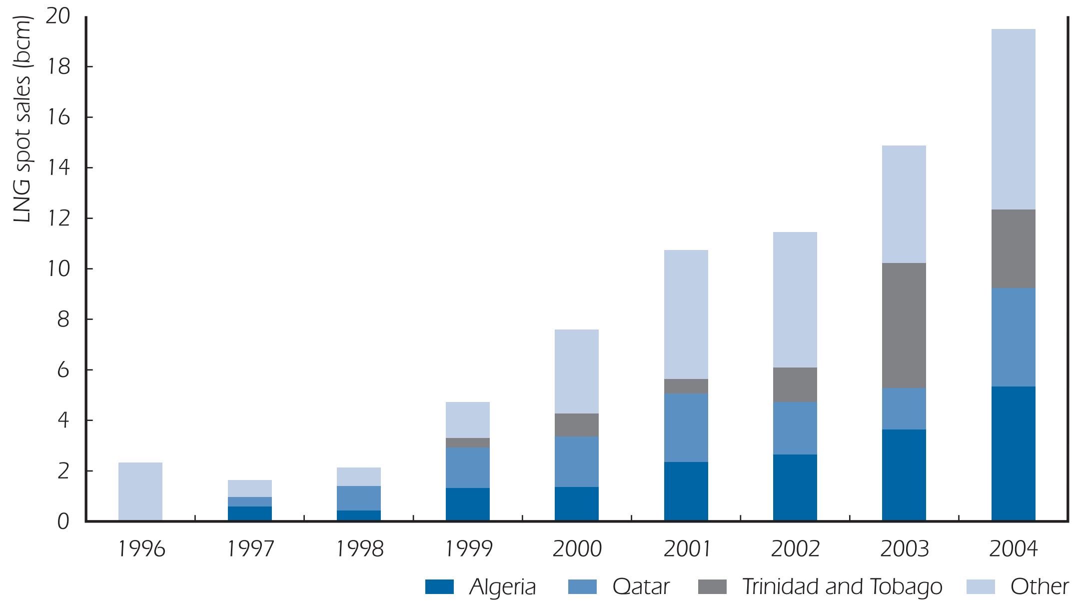
In recent years there has been much speculation about the emergence of a spot LNG market and what this might mean for the LNG industry, both in terms of gas sales and purchases and also the impact on pricing. It is important to notice that the definition of spot is very loosely used around the world. True spot LNG is the LNG produced in excess of contractual arrangements and, therefore, available for sale outside these arrangements. The term is, however, very often used on a wider base whenever there is some flexibility in the destination of the LNG cargoes. For example, when both thre seller and the buyer agree to re-route the cargo to another destination with a higher netback while sharing the resultant profit, or when buyers contract the cargo without a destination clause.

Figure 23 **Fleet of LNG carriers grows exponentially**



Source: Maritime Business Strategies Ltd.

Figure 24 **Spot LNG market grows steadily**



Source: Petrostrategies

The spot LNG market under this wider definition has grown rapidly, by a factor of 10 since 1998, but despite this growth it is still a small market: 19.9 bcm in 2004, or 11.1% of international LNG trade (see Figure 24). It is expected to grow to 20% of LNG sales over the coming years. It is important to note that many of the sales labelled with the spot tag here are in fact flexible arrangements, including short-term sales (for the winter period, for instance) and swaps (for instance, between Spain, United States, Algeria and Trinidad and Tobago). Swaps between piped gas and LNG have enabled Gazprom to deliver its first LNG cargoes to the United States and the United Kingdom.

These spot sales help to balance the market, as producers can sell their excess production and importers can balance their demand more easily, in particular during winter time. Three countries have dominated spot purchases: United States, Spain and Korea. On the supply side, the build-up in contracts, de-bottlenecking of LNG plants and swap arrangements have allowed Algeria, Nigeria, Qatar and Trinidad and Tobago to sell cargoes on a spot basis.

On the spot market, LNG suppliers sell their cargoes to the highest-value market, taking into account the differential for transportation cost (the netback).

So far, trans-Atlantic trade has dominated the spot market, and Spain and the United States were the largest buyers. The declining production in Indonesian LNG, as well as outages at nuclear plants, have forced Asian companies to participate in the spot market as well, and hence, spot prices were high, exceeding Henry Hub prices regularly in winter 2005-06.

Until now, few liquefaction plants or receiving terminals have been built without long-term contracts covering the bulk of the capacity. But the expansion of capacity worldwide and increasing competitive pressures are expected to encourage further growth in short-term trading. Although long-term contracts will probably remain the backbone of the LNG industry, even in the Atlantic Basin market, they could become shorter and take-or-pay commitments may become less onerous. Contract prices may be indexed more and more to spot or futures gas prices, or indeed other composite indices rather than oil prices, reflecting gas-to-gas and inter-fuel competition. One example of this phenomenon is that LNG cargoes to Spain are sometimes priced to electricity indices.

Political risks

The risk associated with the rising LNG demand is not the lack of gas resources. Proven gas reserves are abundant, particularly of the stranded variety most attractive for LNG development. However, even though gas resources are more widely distributed than oil, the largest resources continue to be located in areas of possible regional instability. Most of the LNG projects to be developed over the next five years are located in non-OECD countries, the exceptions being Australia and Norway.

The current situation is comfortable: LNG deliveries from all regions have largely been exemplary. Importing countries have diversified their energy sources and supplies of gas, avoiding geopolitical risks from importing too much from a single region. However, the OECD gas market is becoming more reliant on LNG, and LNG production is concentrated in the Middle East, Indonesia, Nigeria, Algeria, and in the future, Russia. The growing diversity of supply sources may help buyers to mitigate the political risks. Similarly, major companies with investments in affected countries will spread the risks by investing in a portfolio of supply sources.

A very important issue for security of LNG supply is the number of LNG tankers transiting the Strait of Hormuz, the Suez Canal or the Straits of Malacca. For example, a contract between Qatar and the United States involving 15.6 Mtpa would involve a fleet of 35 LNG tankers just to serve the trade between Qatar and the east coast of the United States. The LNG tankers would transit through both the Strait of Hormuz and the Suez Canal. Here again, the security implications are important. Similarly, Qatari supplies to North East Asia would have to transit the Straits of Malacca. The same straits are already intensively used for oil trade, which faces similar issues.

Box 2 **Is gas quality a barrier to the development of the global gas industry?**

The quality of natural gas is defined by its components. Whereas normally methane is the main component, significant amounts of ethane, propane, nitrogen, carbon dioxide and other substances can be present. Although the composition of natural gas can change from field to field, gas-fired appliances in general and domestic appliances in particular, are not equipped to cope with large variations in gas qualitiy. Suboptimal combustion can lead to serious safety problems, such as the emission of carbon monoxide and malfunctioning gas appliances (e.g., flame lift, extinguishing the flame and leading to the emission of unburnt gas). Other problems may occur which do not have an immediate health impact but do cause considerable economic damage, such as soot formation and knocking engines. Historically, therefore, gas-fired appliances have been optimised on the prevailing gas quality found in the region. It was the responsibility of the network operator to keep the gas quality within safe boundaries, indicated by the so-called Wobbe number, a measure for the amount of energy delivered to the burner tip.

Increasing (physical) interregional gas flows, notably LNG, confront the gas industry with a significant challenge, since there can be a large difference in gas quality and as mentioned above, gases are not easily interchangeable for the end-user. Whereas gas quantities easily change hands on paper, the associated molecules sometimes lack that capability in real life.

Although consensus is still being built among network operators, a few options are available to cope with varying gas qualities.

- Not to accept gas with qualities that are not in line with (traditional) specifications. This is an undesirable solution, since it effectively creates market barriers for new entrants. It does, however, put pressure on producers, which sometimes lack the financial incentive to strip undesired components from their LNG.
- Strip undesired components. Currently the main concerns focus on gas which is rich in ethane and propane components. Not only do these components have a higher chance of carbon monoxide formation upon combustion, there is also a possibility that they exert a detrimental effect on pipeline integrity, as recent US lawsuits have shown. It is technically possible to take out ethane and propane from the gas mixture but this is costly and the willingness of the producers to do so is largely dependent on whether they see a better market for the higher hydrocarbons. LNG regasification terminals can also be built to process so-called hot LNG.
- Blend gas to the desired quality. Since main concerns currently focus on gas that is too rich, blending off-spec natural gas with nitrogen, air or carbon dioxide provides means to come on spec, with nitrogen being the industries' choice as the blending agent.
- Improve large end-user flexibility. Large customers may have enough economies of scale to justify either adaptation of their burner systems to new gas qualities, or advanced control mechanisms which measure gas quality.
- Improve small end-user flexibility. Domestic gas appliances, such as boilers and cooking plates, may be replaced by more flexible appliances, capable of handling a broader spectrum of gases. This option might be a major operational and economic challenge, however, since certain countries have a huge number of appliances.

Gas industry and regulators are currently designing gas quality specifications which do not limit gas suppliers in the diversity of sources, nor compromise end-use safety and efficiency. It should be noted that this is a technical issue with a variety of technical solutions; once acceptable and safe standards have been set, the issue is really one – the cost.

GAS-TO-LIQUIDS

The GTL process produces ultra-clean liquid fuels from natural gas. These are gaining popularity in environmentally aware end-use markets. Nevertheless, the production process itself is highly energy inefficient.

There is currently little GTL production, however, there is a keen interest in the process as it allows gas producers direct entry into the premium oil products market.

Economics of investment in GTL plant are dependent on transport fuel prices and low-value gas feedstock. There is a degree of competition between GTL and LNG for stranded resources.

Production and use of GTL

The gas-to-liquids conversion[6] of natural gas into synthetic fuels provides a business strategy for gas monetisation. GTL not only adds value by converting low-value gas into oil, but it yields superior quality hydrocarbons that can be blended to produce lower-emission, higher-quality fuels. These are important characteristics considering the high cost of meeting demand in the growing ultra-low sulphur diesel market. Current GTL production is equivalent to less then 0.3% of the OECD countries gas oil/diesel demand, but its blending properties multiply its importance to this growth sector. While GTL is attractive to refiners, GTL projects are themselves highly capital-intensive, and the process itself is also energy-intensive. Only 60% of the energy content of the feedstock ends up in the final product. GTL technology is now seen as a potential alternative to LNG: both technologies are as a way of exploiting gas reserves in remote locations.[7]

Besides the need for diversification of energy supply, the drivers contributing to the renewed and growing interest in GTL from a consumer perspective are primarily environmental. Products such as diesel can be derived from oil and gas via the GTL process, but GTL products are environmentally superior to existing oil-derived products because they have no or very low levels of sulphur and aromatics, and are more homogenous, leading to a relatively higher cetane index.[8] These qualities lead to significant reductions in particulate matter that is generated during combustion, and reduce the toxicity of the particulate matter. They also allow the upgrading of low quality gasoil into diesel, which is a key issue for refiners.

These environmental features of GTL products command a price premium. The trend is toward increasing demand for cleaner fuels in many countries. The

6. The GTL process involves three key steps. The first step is desulphurisation and production of synthesis gas. The second step involves converting the synthesis gas into a liquid hydrocarbon by means of a Fischer-Tropsch catalytic reaction. The third step is hydrocracking to yield the desired range of distillates and paraffins.

7. It is possible to use coal or even biomass as a feedstock to produce synthetic oil in a similar process: coal-to-liquids (CTL). This option is not treated in this Section.

8. A value calculated from the density and distillation properties of a fuel, used as an alternative to the cetane number to indicate relative diesel ignition quality.

Table 2 Global GTL projects

Project name	Capacity (kb/d)	Status	Company	Location
Bintulu	14.7	existing	Shell	Malaysia
Mossel	25	existing	PetroSA	South Africa
Oryx	34	under construction	Sasol, Chevron and Qatar P.	Qatar
Escravos	34	under construction	Chevron/NNPC	Nigeria
Pearl	140	advanced planning	Shell, Qatar P.	Qatar
Tinhert	36	advanced planning	Sonatrach	Algeria
Exxon Qatar	154	postponed due to moratorium on North Field	Exxon	Qatar
Sasol Qatar	130	postponed due to moratorium on North Field	Sasol Chevron	Qatar
Conoco Qatar	80	postponed due to moratorium on North Field	Conoco	Qatar
Marathon Qatar	120	postponed due to moratorium on North Field	Marathon	Qatar
Ivanhoe	45	speculative	Ivanhoe Energy, Egas	Egypt
Russia	?	speculative	Shell	Russia
Iran	?	speculative	Sasol	Iran
Venezuela	?	speculative	?	Venezuela
Bolivia	?	speculative	?	Bolivia

Source: IEA data, company statements

European Union is now finalising legislation that will mandate sulphur-free diesel for on-road use by 2009. Several countries in other regions, including the United States, Japan and Australia, are heading the same way. Additionally, recent technological advances, including improved catalysts, have significantly improved product yields and reduced both capital and operating costs of GTL projects. This, combined with the sharp increases in oil prices in recent years, has improved the economic attractiveness of the GTL option, although increasing gas prices are tending to counteract this somewhat.

Current and projected GTL capacity

There are currently two GTL plants in operation in the world with a total combined capacity of 37.7 kb/d. The first one is Shell's 14.7 kb/d Bintulu plant in Malaysia, and the second one is PetroSA's 25 000 kb/d Mossel plant in South Africa. The Bintulu plant uses Shell's proprietary Middle Distillate Synthesis (SMDS) technology and the second uses Sasol F-T technology. Both plants started operations in 1993.

Capacity currently under construction totals 68 kb/d and includes two plants of 34 kb/d each. The Oryx plant in Qatar is expected to start production by the second quarter of 2006. Oryx is the first ever project-financed GTL plant. It will have the following production mix: 24 kb/d of diesel, 9 kb/d of naphtha, and 1 kb/d of LPG. Oryx is a joint venture between Qatar Petroleum and Sasol. The Escravos plant in Nigeria is planned for start-up by mid-2009. Chevron, the principal shareholder of the Escravos project, announced in February 2006 its intention to triple the size of that plant to benefit from economies of scale.

Capacity planned and under development for commercial-scale GTL plants exceeds 773 kb/d, including six projects in Qatar, one in Algeria and one in Egypt. If all the projects go ahead, Qatar will have the largest GTL capacity in the world with over 658 kb/d by 2012. Qatar's interest in LNG and GTL reflects the importance of its natural gas reserves, the third-largest in the world, with more than 14% of the world total. Shell signed a contract with Qatar Petroleum in October 2003 for a 140 kb/d GTL facility to be built at Ras Laffan. The first 70 kb/d of capacity is expected to commence operation by 2009, with the rest in 2011. When completed, it will be the world's largest GTL plant. The fully integrated project will utilise gas from the North Field as feedstock. However, cost estimates for this project have risen from USD 5 to 8 billion and Shell is only to make its final investment decision later in 2006.

An actual moratorium on new gas projects, imposing a cap of 0.7 bcm/d (25 bcf/d) on production from the Qatari North Field, may delay or constrain the implementation of further projects in Qatar. This uncertainty may be cleared by mid-2007, when additional reservoir modelling will provide better understanding of the production capacity of the North Filed.

Market potential and outlook

Reflecting growing environmental concerns, the market for clean fuels for vehicles is expanding rapidly in OECD countries and the potential demand for clean GTL products is, therefore, large. GTL diesel has two market applications: it can be blended with conventional diesel to meet lower sulphur specifications, or it can be sold as a spec product for use by buses, trucks or other utility vehicles to alleviate air pollution problems in major cities. The gas oil and diesel oil markets account for about 13 mb/d of OECD countries' consumption, so current GTL production represents less than 0.3% of the potential market size. If all the GTL capacity currently planned and under development is built, this will represent 6% of the current conventional gas oil and diesel oil market, but the net effect on the diesel market would be much larger as GTL could be used to upgrade low-quality gasoil to diesel.

How quickly GTL projects can be implemented will depend to a large extent on GTL project economics and acceptance from financial institutions, recognising that GTL projects are highly capital-intensive and relatively risky. The economics of GTL processing are highly dependent on plant construction costs, the gas feedstock costs, the product yields, the energy efficiency of the plant, as well as the market prices of the liquids produced, or alternative destinations for the stranded gas in the form of LNG. Based on industry estimates, the capital costs for GTL projects tend to be in a range of between USD 20 000 and 30 000 per daily barrel of capacity: nearly double that of refinery costs. GTL processes typically require about 10 MBtu of gas to produce one barrel of fuel. Thus, a change in the cost of gas feedstock of USD 0.50/MBtu would shift the synthetic fuel production cost by around USD 5/bbl. Based on estimates by the United States Energy Information Administration, the cost of GTL fuel from a hypothetical GTL plant would be USD 25/bbl, which comprises a capital cost of USD 10.48/bbl, an operating cost of USD 5.5/bbl and assumes a feedstock cost equivalent to USD 0.9/MBtu (USD 8.92/bbl).

GTL and LNG may compete for the same gas feedstock in some cases, but they serve different end-use markets: LNG is aimed at gas markets, while GTL is primarily destined to fuel markets, representing a diversification of revenue source for the producer. Therefore, both can be viable and complementary alternatives to exploit isolated gas reserves. With April 2006 gas prices of around USD 7/MBtu and ultra-low-sulphur fuel of around USD 85/bbl, netbacks for both options seem to be roughly equal, but this may change should oil prices stay high and gas prices drop or *vice versa*.

INVESTMENT IN THE GAS SECTOR

Projects under construction in the gas sector amount to around USD 210 billion over the period 2005-10, compared with requirements of around USD 520 billion according to the IEA benchmark World Energy Investment Outlook (WEIO) 2003. There is a serious risk of under-investment in the sector unless all projects currently planned are also delivered by 2010, which is unlikely.

LNG constitutes only 6% of total gas demand, but accounts for over half of all investments in the gas sector. The bulk of the LNG projects are backed by contracts with OECD countries. The private sector is largely responsible for bringing these complex and capital-intensive projects to fruition. Conversely, pipeline investments look weaker, especially outside OECD countries.

Gas-fired power stations continue to attract a large amount of investment in OECD Europe and North America. There are early signs of higher gas prices affecting further growth in the period beyond 2010.

General trends in gas sector investment

This Section analyses investment behaviour in the gas sector with specific attention to the period 2006-10. For this period gas supply projects worth a total of USD 210 billion are under construction, with an additional USD 300 billion planned.[9] This would imply possible total spending of USD 102 billion per year. In assessing the adequacy of these investments, the IEA World Energy Investment Outlook can function as a useful reference, notwithstanding some definitional differences.[10] According to the WEIO 2003, cumulative global investment requirements in the natural gas supply chain in the period 2001-30 are USD 3.1 trillion, or an average of USD 105 billion per year. Therefore, it would appear that current investments are broadly in line with projections only if all planned projects proceed. However, it is unlikely that all planned and proposed projects will be completed by the end of the decade. This is because the numbers also include some more speculative projects which will not be on stream by 2010 if the final investment decision has not been made by early 2006. Although a five-year period is not a sufficient indication of long-term investment behaviour there is a serious risk of under-investment in the overall gas sector.

9. Information is collected from company statements and published sources on project-based spending and covers, therefore, mainly major new developments. Additionally, companies are likely to spend substantial amounts on maintenance and minor infrastructure projects. The aim of this Section is to identify the current trends in natural gas investments. "Under construction" is, therefore, taken literally. "Planned", on the other hand can range from highly probable to quite speculative projects. An exception is made for LNG re-gasification terminals, where the authors found it wise not to include all proposed projects, but rather only a selection, focussing on the most advanced ones. This can be attributed to the fact that many experts consider it unlikely that all of the terminals proposed will be built, certainly not within the time frame of this review. The best example is North America, where a stunning 67 potential projects have been identified by FERC, but only 6 are under construction.

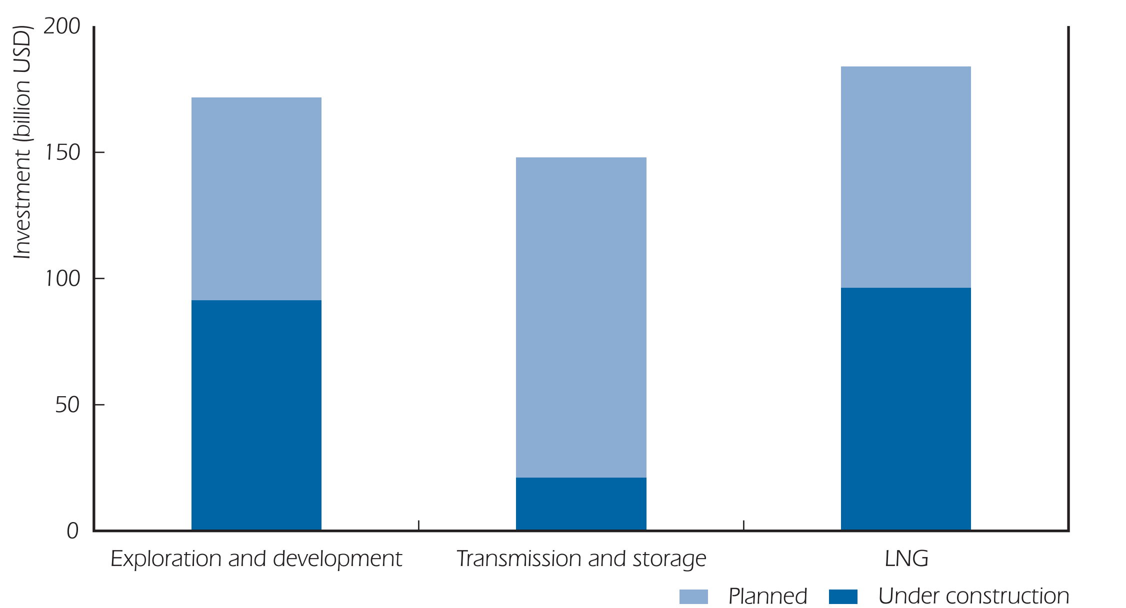
10. *World Energy Investment Outlook* assesses investment needs on the basis of projected demand, supply and assessment of company plans through to 2030, whereas this review is taking a relatively short-term snapshot based on published sources.

Figure 25 shows the investments in projects that are currently under construction or planned in the main parts of the natural gas supply chain. Projects worth USD 91 billion are under construction in exploration and development in the period of 2006-10 and the figure could double if all planned projects came to fruition. Projects worth USD 21 billion are under construction in the transmission and storage part of the value chain; USD 122 billion, remarkably more, is either planned or proposed. Projects worth USD 96 billion are under construction in LNG projects, including liquefaction, shipping and re-gasification (excluding exploration and development). A further USD 88 billion is planned in this sector.

Of the USD 172 billion total expenditure on exploration and development, over half is attributed to gas fields supplying LNG production facilities. Given that LNG currently only constitutes 6% of total global gas consumption, its proportion of total investment is remarkable. This clearly shows that LNG is a rapidly growing industry but also indicates that investment in pipelines is lagging. Of course, the pipeline industry is relatively mature, whereas LNG is a rapidly expanding industry (see the LNG Section). It is noteworthy that LNG projects are mainly backed by contracts with OECD countries.

Many smaller pipeline investments go unreported and are, therefore, not included in this analysis which is based on published sources, whereas all LNG projects attract wide coverage. Notwithstanding these important caveats, the bias towards LNG investment appears quite marked, and the low level of committed transmission and storage investment is of concern. The possible reasons for this are explored below.

Figure 25 **Investment focuses on LNG**



Source: IEA data, company data, published sources

Review of major pipeline investments

A number of multi-billion pipeline projects is proposed, but few have reached positive final investment decisions. Compared with the more flexible LNG projects, pipelines create a decades-long mutual dependence between one supplying region and one consuming. Gas supply chains are becoming longer and when international frontiers are crossed, political considerations become critical factors. This does not encourage quick development of new projects. Nevertheless, in many cases pipelines are still the preferred transportation method for natural gas due to their relative high capacity, favourable geographical circumstances and straightforward design, engineering and construction. A few important projects have been recently completed and others are under very active consideration.

Blue Stream

Although functioning from 2003, 2005 saw the official inauguration of the Blue Stream pipeline, a USD 3.1 billion, 1 213 km, sub-sea pipeline connecting Russia and Turkey with an ultimate capacity of 16 bcm per year. The pipeline represents state of the art technical aspects and is, therefore, an impressive feat of engineering. However, although it is growing rapidly, gas demand in Turkey is lagging behind expectations, and, therefore, some question the financial viability of the pipeline. The current use of the Blue Stream is 3.2 bcm per year, leading to the argument that the primary purpose of Blue Stream is to provide all Turkey's gas needs and to deny that market to any pipelines from the Caspian or the Middle East region to Europe.

Greenstream

With operations commenced in 2005, the Greenstream pipeline links Libya to Italy. Annual throughput of 8 bcm is expected to be reached in 2006. The cost of this project, which started in 1999, is estimated at USD 1 billion. Supplying new power generation facilities in Italy was a major driver for this investment.

Langeled

Due on stream in late 2007, the Langeled connects the Norwegian Ormen Lange gas field with the United Kingdom via a gas processing plant at Nyhamna. The 1 200 km, 20 bcm per year, USD 2.9 billion pipeline, and the USD 7 billion Ormen Lange development, are part of the investments in gas infrastructure (including pipeline supplies and LNG terminals) to the United Kingdom to make up for its declining domestic production of natural gas.

North European Gas Pipeline (NEGP)

The subsea North European Gas Pipeline will connect Russia with Germany. Construction of the 1 198 km offshore section of the pipeline, running from Vyborg to Greifswald, is slated to start in 2007, but the Final Investment Decision has yet to be made. Notwithstanding this, construction has already started on the additional 917 km onshore pipeline connecting Vyborg with the United Gas Transmission System of Russia. The pipeline, due on stream in 2010, will have an initial capacity of 27.5 bcm per year, possibly expanded to 55 bcm per year. Investments in the first pipeline will be about USD 6 billion, with the offshore part accounting for almost half of this amount. An agreement between Gazprom (51%), E.ON AG (24.5%) and BASF AG (24.5%) has been concluded to form a Joint Venture, but Gazprom has not excluded other European parties from entering the JV. Whereas some welcome the NEGP as a new route for Russian gas, increasing security of supply to the countries most suffering from declining North Sea gas production, and bypassing transit countries, others claim that the NEGP is a strategic tool enabling pressure to be exerted on the Baltic states, Belarus and Poland by bypassing these countries with an expensive offshore pipeline. As of early 2006, only Wingas (a Gazprom/Wintershall subsidiary) has contracted supply via the NEGP. Supply will ultimately come from the Southern Russkoye gas field which will be jointly developed by Gazprom, Wintershall and possibly other companies.

Nabucco

The 3 300 km Nabucco pipeline is designed to transport around 30 bcm per year from the Middle East and Caspian regions to Europe. A Joint Venture comprising Turkey's Botas, Bulgarian Bulgargas, Romanian Transgaz, Hungarian MOL and Austrian OMV Gaz was setup in mid 2005 to study the USD 5.4 billion project that could technically be on stream in 2011, at the earliest. Since this pipeline will cross many countries and source gas from a region which is politically unstable, any completion date is heavily dependent on political factors. Nabucco would function as an important means of diversifying supply to Europe, especially to the parts of Europe which are currently supplied by Russia. No supplier is part of the project yet, which seems a major hurdle given the political situation in the Middle East. Recent concerns over security of supply in Europe and dependence on Russia after the January 2006 supply disruptions of Russian gas could spur the development of Nabucco.

Alaska gas pipeline

Although on the design table for several decades, no final investment decision has been made on the 6 000 km, 50 bcm per year pipeline, transporting gas from the Prudhoe Bay area in Alaska's North Slope through Canada to the lower 48 states (see Figure 37). Nevertheless, the project has entered a new stage after a tax agreement was concluded between the operators of the pipeline and the state of Alaska in February 2006. This is even more remarkable, considering that only in late 2005 a lawsuit had been filed against BP and ExxonMobil for withholding gas from the market in order to drive up prices. The project has the potential to supply almost 10% of the annual North American gas demand, thus decreasing the dependence on foreign LNG and increasing security of supply. The pipeline could certainly have a major impact on gas availability and thus prices in the United States, which could affect the development of alternative gas supplies, such as LNG or other domestic production. Costs have long been estimated at USD 20 billion, but steel and labour costs have increased substantially in the interim. An alternative project has been proposed involving a 800 km pipeline to Valdez and subsequent liquefaction and transportation in the form of LNG. Either way, North Slope gas is not expected to reach American customers before 2012, or more likely 2015.

Rocky Mountains

Two pipelines have been announced to transport gas from the Rocky Mountains to the Midwest and Eastern states: the Rockies Express, a 1 500 km, 25 bcm per year, USD 3 billion investment and the Continental Connector, another 1 500 km 25 bcm per year project. If approved, both could be operational by 2008-2009, being the largest pipelines built in the United States in the last 20 years. The proposed pipelines are a response to the increasing production in the Rocky Mountains, triggered by high gas prices in North America.

West-East Gas Pipeline

In 2004, the Chinese National Petroleum Corporation (CNPC) completed the West-East gas pipeline, a 4 000 km, 12 bcm per year pipeline connecting the Tarim basin gas fields in the western Xinjiang region with the eastern Shanghai region. The total costs of this project have been estimated at USD 18 billion, including field development and distribution networks in the Shanghai area. In the early stages of the development of the pipeline, Royal Dutch/Shell, ExxonMobil and Gazprom were partners in the project but they withdrew after disagreements on the expected return on investment and after having contributed significantly to the solution of technical challenges in the design stage. Not only does this project promote the economic development of the Western Chinese region, it also provides a means for China to lower its dependence on foreign energy resources to fuel its booming economy. An expansion is currently under consideration as the design capacity has been found to be inadequate.

Dolphin project

At a cost of nearly USD 7 billion, the Dolphin project is intended to come on stream at the end of 2006. It is yet another project to deliver natural gas from the super-giant Qatari North Field, in this case to the Gulf states of Abu Dhabi, Dubai and Oman. The project consists of an offshore pipeline from the North Field to a gas processing plant in Ras Laffan, then a 370 km 41 bcm per year offshore pipeline to Abu Dhabi and a further onshore pipeline network to customers in Abu Dhabi, Dubai and Oman. Initial sales are expected to be 20 bcm. If not for its size, the project is also significant for demonstrating the increasing awareness of Middle East countries of the value of natural gas for domestic use, either for creating added value by using the gas as a feedstock for the production of bulk chemicals, for generation of electricity and desalinated water, or even for enhanced oil recovery. Domestic use of formerly stranded gas fields will slowly provide serious competition to possible exports to OECD countries via LNG.

West African Gas Pipeline

With a capacity of 5 bcm per year and total investments of USD 590 million, the West African Gas Pipeline (WAGP) is a relatively small investment project. Supplying associated gas that was formerly flared at Nigeria's oil fields to Ghana, Togo and Benin, the project does, however, show the slow emergence of a gas industry in

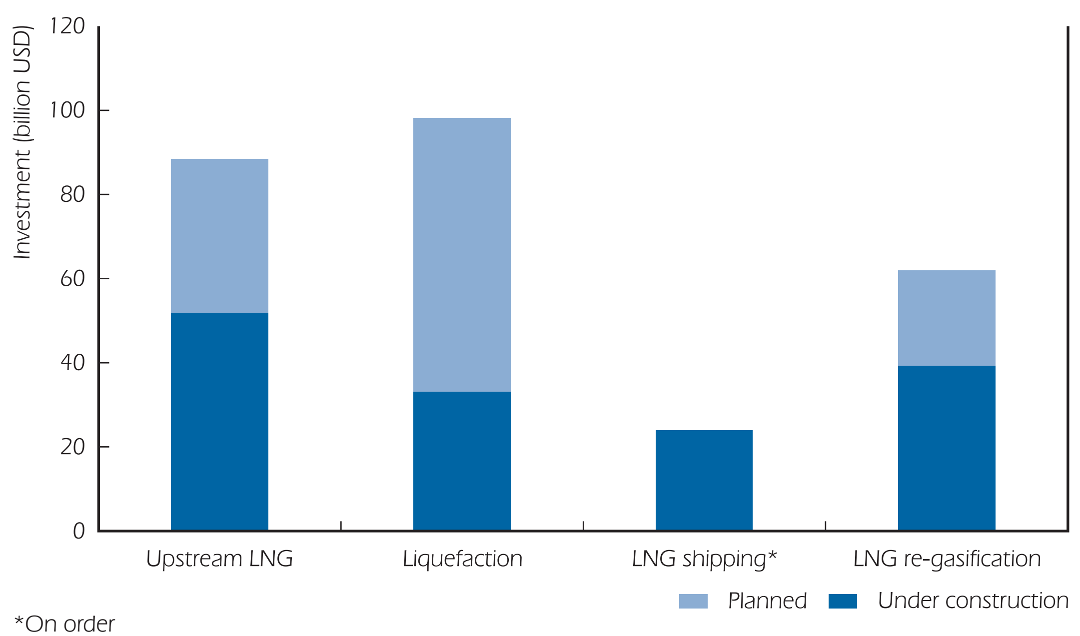
Western Africa, replacing more expensive imported oils. It shows the increasing value of natural gas for domestic use, mainly the generation of electricity, as opposed to export in the form of LNG.

Review of LNG investments

Total investment in the LNG sector in the period 2006-10 amounts to USD 272 billion, of which USD 148 billion is under construction and another USD 124 billion is planned or proposed.

Although complete LNG value chains require multibillion dollar commitments, LNG investments have been requiring less time to market than many similar-sized pipeline projects. The focus and drive of international oil companies on LNG projects may explain this relative success. Whereas national governments or national oil companies tend to gain more and more control over the production of piped gas, IOCs still have a competitive advantage in the LNG market; hence this sector is becoming more important in the product portfolio of IOCs. They are more familiar with the technology and have the skills to manage such mega-projects. IOCs also provide considerable global market expertise and are often present in the regional markets. Due to their diversified supply portfolio, they are a reliable partner for buyers of LNG and due to their high credit ratings they are a reliable partner for banks. IOCs are responsive to strong market demands and can provide substantial equity in relatively short time frames.

Figure 26 **Significant investment throughout the LNG chain**



Source: IEA data, published sources, company statements

Another important feature which stimulates investment in LNG is that it allows suppliers to have multiple buyers in order to spread risk. Since geographical boundaries are less of an issue vis-à-vis pipelines, LNG can be produced from the cheapest gas available and sold at the highest netback (when the contracts are flexible). LNG also creates possibilities for new entrants to capture market share in former natural monopoly markets. As transport costs have fallen compared to prices, this factor becomes more significant.

Fuelled by stagnating domestic production in mature OECD Europe and OECD North America and backed by high gas prices in these countries, liquefaction plants are in operation or close to development in countries like Australia, Yemen, Equatorial Guinea, Egypt, Qatar, Iran, Nigeria, Angola, Norway, Russia, Peru, Indonesia, Malaysia, Algeria, Egypt, Oman, Libya, United States (Alaska) and Trinidad and Tobago, where hitherto stranded or low-value gas is found (see Annex A). Of these, Australia, and to a smaller extent Norway, are the only OECD countries that are likely to contribute significantly to the production of LNG in the near future. Nevertheless, most LNG projects are backed by contracts with OECD companies and supply OECD markets. several outstanding developments are highlighted below.

Box 3 ***Will a shortage of qualified engineers hinder the development of the gas industry?***

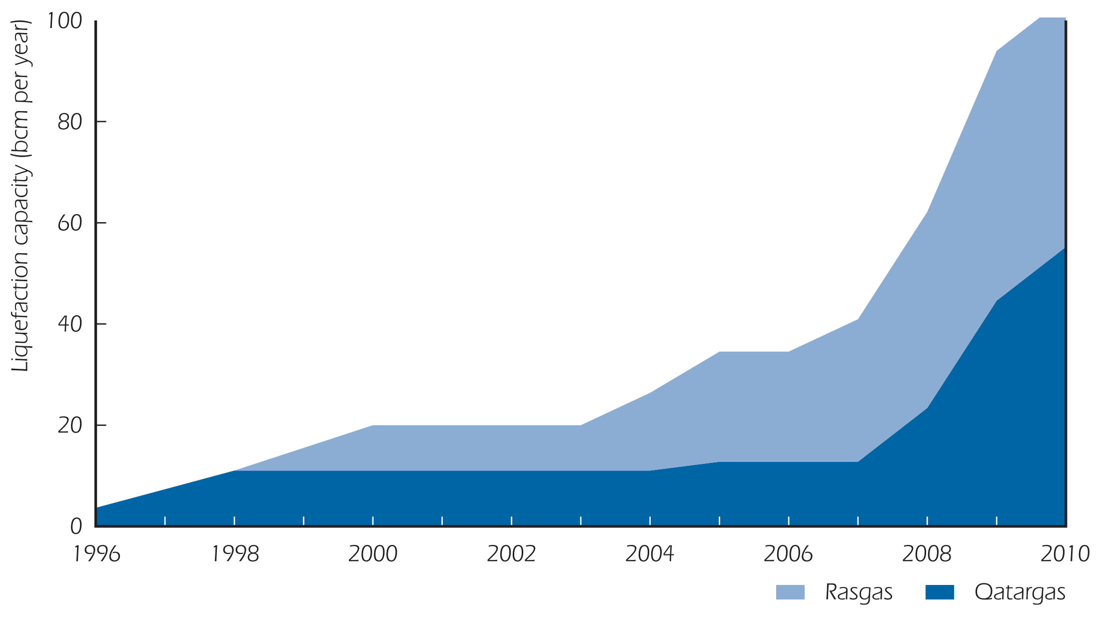
One of the consequences of the technical complexity of LNG facilities is the tight availability of material and skilled labour. Demand tends to outpace skilled labour formation, simply due to the speed of industry expansion rates. It takes time to train new staff and pass on experience, particularly because of the changing requirements to employee qualifications and the growing complexity of gas projects. Finding adequate numbers of engineers, geologists and other geoscientists has become a challenge across the industry. The shortage of qualified professionals is particularly acute in the US, where the number of graduates in the relevant fields is at its lowest in decades.

Greenfield projects in most cases call for specialised skills for the whole project staff from the very start. As the majority of the easy reserves has already been developed, most of the new projects imply a higher technological challenge. In order to stay competitive and meet growing gas demand, existing projects need debottlenecking and revamps, which puts further pressure on skilled labour. With the growing competition for skilled workers, labour costs rise, pulling with them the overall costs of gas projects. This risks slowing down investment and increasing project lead times.

Qatar

Qatar's North Gas Field holds proven reserves of around 26 tcm, making it the largest known gas reservoir in the world. Along with a government-induced favourable investment climate, these resources have attracted large investments over recent years. Around 2010, Qatar should produce 105 bcm per year (77 mtpa) of LNG approaching one third of total global production. Two projects, Rasgas and Qatargas, have been developed to produce LNG and the capacity is all contracted, albeit on more flexible terms than the traditional LNG model. The majority of this increase is funded by IOCs and, therefore, a large part of the LNG is expected to end up in the highest-value market. Besides LNG, one of the world's largest gas-to-liquids facilities is being built in Qatar: Oryx GTL, with a capacity of 34 kb/d. A final investment decision on Pearl GTL, with an ultimate capacity of 140 kb/d of liquid transport fuels is to be made in 2006, and there is a large interest in more Qatari GTL plants. Although Qatar Petroleum is a majority shareholder in both LNG and GTL projects, the country welcomes foreign involvement in the projects and international oil companies have invested keenly. Qatar has now issued a moratorium on the start of new projects until 2007 in order to investigate the best means to further explore the North Field. Several projects are already awaiting approval after that period.

Figure 27 Rapid development of Qatari LNG production capacity



Source: IEA data, company statements

Australia

Australia is currently a relatively small producer of LNG (2004 production was 12.6 bcm, or 9.3 mtpa). Production, both existing and proposed, is based on stranded gas reserves located offshore of Western and northern Australia. A new liquefaction plant in Darwin delivered its first cargoes in February 2006 and the fourth train of the North West Shelf Joint Venture, already operating, is scheduled to commence deliveries to China in mid-2006. These plants take Australian LNG output to over 20.4 bcm per year (15 mtpa). In June 2005, the partners in North West Shelf announced they would proceed with the construction of the fifth train (6 bcm, or 4.4 mtpa, by 2008) without having long-term contracts in place, something seldom seen in the gas, or especially the LNG, market. There is a large interest in the development of Gorgon (1.1 tcm of reserves) and Pluto (the field was only discovered in April 2005). Both projects have announced sales agreements, and final investment decisions are expected later this year, with production of 20-23 bcm per year (15-17 mtpa) targeted for 2010. If these projects proceed, Australia would become one of the top three global LNG producers.

Several other LNG projects are under consideration. In early April 2006, the Japanese company Inpex announced plans to develop the Ichthys gas field in the Browse basin into a 6.8-8.1 bcm per year (5-6 mtpa) LNG plant, with an expected start-up as early as 2010. Additional projects include Browse, Scarborough (Pilbara LNG), Sunrise and Darwin phase 2. Of these, Browse is looking at a 2011-12 start-up and is already marketing gas. Darwin LNG has site approvals for up to 13.6 bcm per year (10 mtpa). Pilbara LNG is looking at possible LNG deliveries to the BHP Billiton offshore LNG receiving terminal under consideration in California. Companies appear eager to develop projects in politically-stable Australia rather than in other localities of the world, noting that the offshore locations and the relative isolation of gas reserves make development costs higher.

Russia

Russia holds the largest gas reserves in the world, but new fields are increasingly isolated and LNG is seen as an important future technology to develop resources and to enter new markets like Japan and the United States. At this moment, Sakhalin 2 is the only liquefaction project under construction in Russia, with a capacity of 13 bcm per year. The project is operated by Shell, until now without Gazprom involvement, but both companies are looking at the possibility of exchanging a stake in Sakhalin for one in the Zapolyarnoye field. Shell announced in 2005 that the project budget would double to USD 20 billion, due to higher steel costs, severe conditions and unexpected expenses on environmental issues. Even though the development costs are high compared to other liquefaction projects, access to Russian gas resources and diversification of supply portfolios are important attractions to major oil companies. After Sakhalin (2009), the Shtokman field in the Barents Sea may host another LNG project. Gazprom intends to develop the field and export the gas as LNG, but the company currently lacks the technical expertise. Five IOCs are shortlisted to form a Joint Venture, but completion is not expected before 2012.

North America

FERC estimates that there are currently 67 projects for LNG terminals or terminal expansions in North America, with a combined send-out capacity of around 2 000 mcm/d (70 bcf/d), roughly equal to average daily (normal) demand for the whole United States. It should, however, be noted that only 18 projects have been approved by the national authorities and 6 are actually under construction. Depending

Table 3 North American approved re-gasification terminals as of April 2006

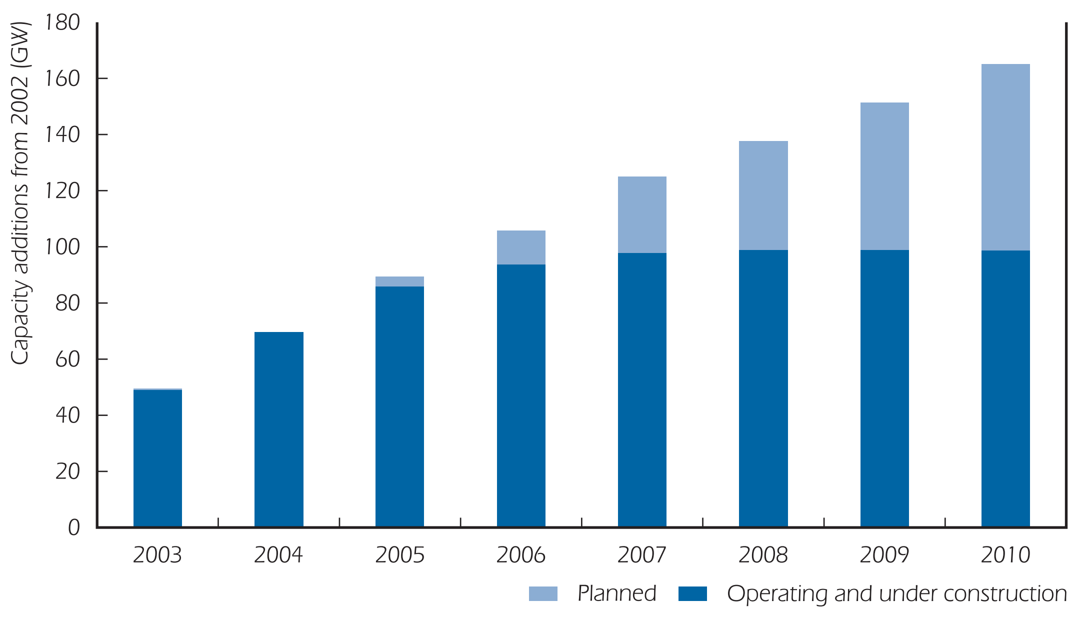
Approved by	Terminal	Project proposal by	Status	Capacity addition (mcm/d)	Capacity addition (bcf/d)
FERC	Lake Charles LA	Southern Union-Trunkline-LNG	under construction/finished	17.0	0.6
FERC	Hackberry	Cameron LNG-Sempra Energy	under construction	42.5	1.5
FERC	Bahamas	AES Ocean Express	not under construction	23.8	0.8
FERC	Bahamas	Calypso Tractebel	not under construction	23.5	0.8
FERC	Freeport	Cheniere/Freeport LNG	under construction	42.5	1.5
FERC	Sabine	Cheniere LNG	under construction	73.6	2.6
FERC	Corpus Christi	Cheniere LNG	site prep begins Q2 2006	73.6	2.6
FERC	Corpus Christi	Vista del Sol-ExxonMobil	not under construction	28.3	1.0
FERC	Fall River	Weavers Cove Energy	not under construction	22.6	0.8
FERC	Sabine	Golden Pass ExxonMobil	not under construction	28.3	1.0
FERC	Corpus Christi	Ingleside Energy	not under construction	28.3	1.0
MARAD/ Coast Guard	Port Pelican	Chevron	not under construction	45.3	1.6
MARAD/ Coast Guard	Louisiana offshore	Gulf landing-Shell	not under construction	28.3	1.0
Canada	St. John	Canaport-Irving Oil	not under construction	28.3	1.0
Canada	Point Tupper	Bear Head LNG-Anadarko	construction re-scheduled	42.5	1.5
Mexico	Altamira, Tamulipas	Shell/Total/Mitsui	under construction	19.8	0.7
Mexico	Baja California	Energy Costa Azul-Sempra	under construction	28.3	1.0
Mexico	Baja California offshore	Chevron	not under construction	39.6	1.4
Total approved capacity addition				**636**	**22.5**
Total capacity addition under construction				**266**	**9.4**

Source: FERC, company websites and statements on the location, terminal proposals have been facing strong local opposition, the so-called Not In My Back Yard (NIMBY) effect. In addition, it has proven difficult to line up supply, especially for smaller companies. The tight LNG market worldwide in 2005 showed that Asian and European companies have been willing to pay higher prices than their North American counterparts. Instead, hurricane-related gas price increases in the United States' market have induced demand reduction and added impetus to efforts to raise domestic production. Construction of the Bear Head LNG terminal was temporarily halted to be more in line with expected supply. A similar situation can be observed in Italy, where there are 10 proposals for new re-gasification terminals, but only one or two are likely to be built in the short term, given strong NIMBY issues.

Review of investments in gas-fired electricity generation

In the last decade, investments in electricity generation among OECD countries have been increasingly focussed on gas-fired power installations (the so called "dash for gas"). In the period from 2002 up to and including 2010, IEA estimates, based on capacity additions, that around USD 93 billion is or will be spent on gas-fired power plants, and an additional USD 72 billion is planned. This totals USD 166 billion, or more than USD 20 billion per year, not including investments in related (power) transmission and distribution infrastructure, which could double the figure. It is possible to construct gas-fired power plants (see Gas for Power Generation Section) in a time frame of

Figure 28 **Slowdown in capacity additions in IEA North America**



Source: IEA analysis based on PLATTS data

2-3 years, or even shorter if it concerns brown-field expansions. The capacity additions that are currently under construction for completion in 2006, 2007 and 2008 are, therefore, especially important in analysing investment trends in gas-fired power generation. The planned additions are much less certain.

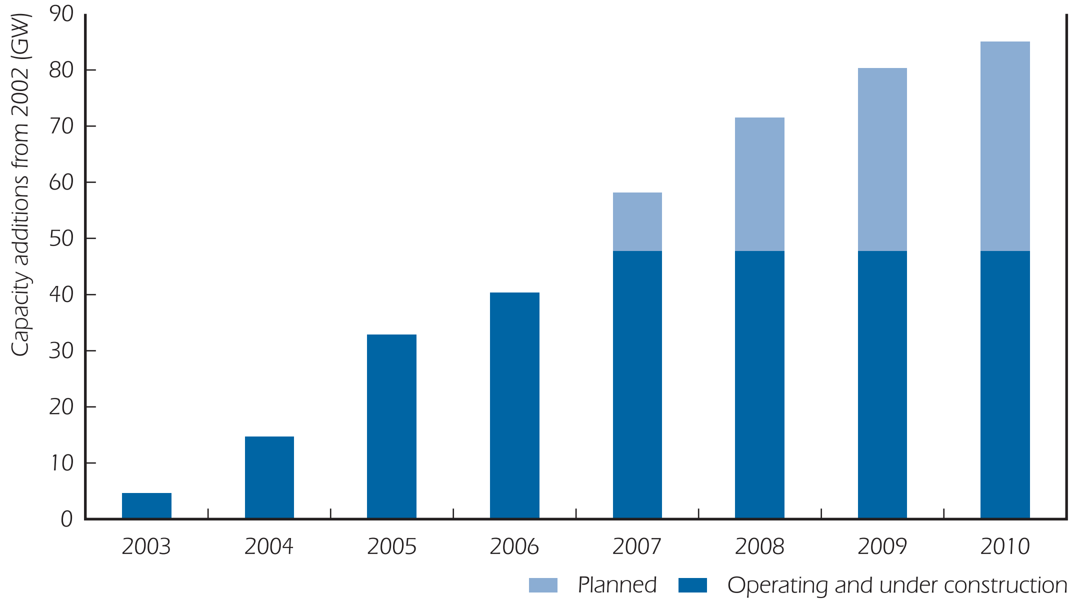
The majority of the added capacity will be constructed in North America and Canada. These countries have or will construct 99 GW of gas-fired power generation in the period 2002-10, with a further 66 GW planned. Interestingly, the WEIO projected capacity increase for the period to 2010 (85 GW) was already under construction by 2005, and by 2010 the number will be higher. As explained in the Gas for Power Generation Section, this may well be due to a shift in portfolio build-up by the power generators. Towards the end of this period, the first signs of a levelling-off in gas-fired power are being seen, under the influence of higher prices.

OECD Europe is also ahead of projections, with 48 GW of gas-fired power built or under construction compared to 43 GW in WEIO. Another 37 GW are planned (Figure 29).

In the same period, OECD Pacific countries have been building or will build 9 GW of gas-fired electricity generation, whereas another 17 GW is planned. OECD Pacific countries are not increasing their gas-fired power capacity as fast as the WEIO projection of 32 GW of additional capacity between 2003 and 2010. This is possibly due to lower growth in overall power demand in the region.

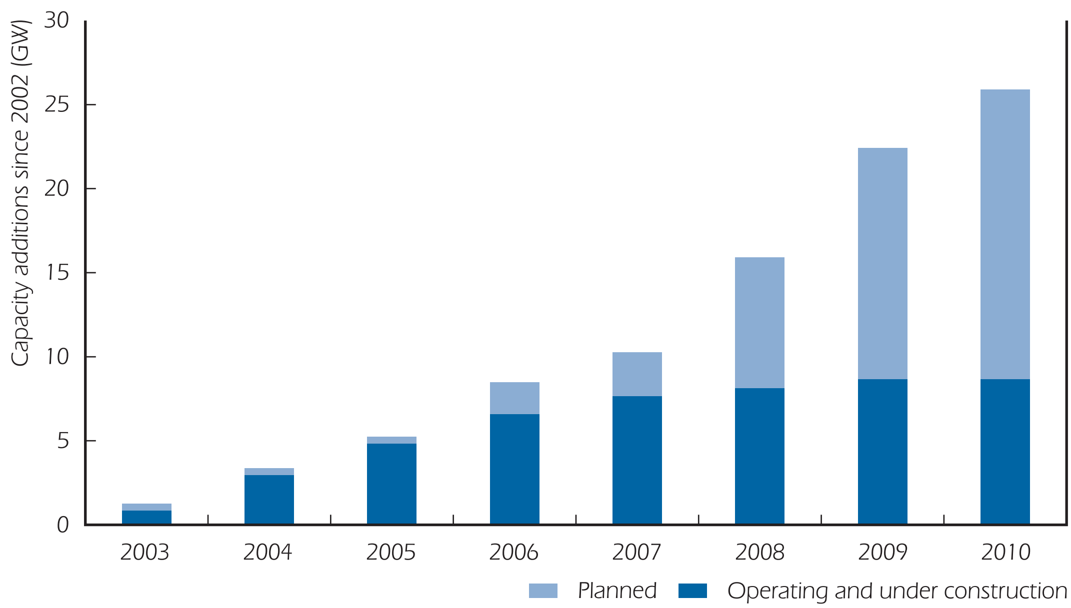
In summary, gas-fired power investment is strong and it is a driving force for gas demand. The impact of higher gas prices and perceived market tightening is yet to be seen. however, beyond 2010 evidence is starting to emerge that there is a slowing in forward orders for gas turbines.

Figure 29 **Continuing capacity additions in IEA Europe**



Source: IEA analysis based on PLATTS data

Figure 30 **IEA Pacific careful with new capacity additions**



Source: IEA analysis based on PLATTS data

GAS PRICES AND MARKET DESIGN

Gas prices increased in all major markets in 2005 and 2006, driven by linkages to oil, or gas market fundamentals in markets such as North America and the United Kingdom.

Different regions of the world use different pricing systems. Interaction between these systems is creating tensions and opportunities.

Supply response to market tightness has long lead times, whereas demand response is immediate. This makes the gas market inherently volatile, although there are many ways to manage volatility.

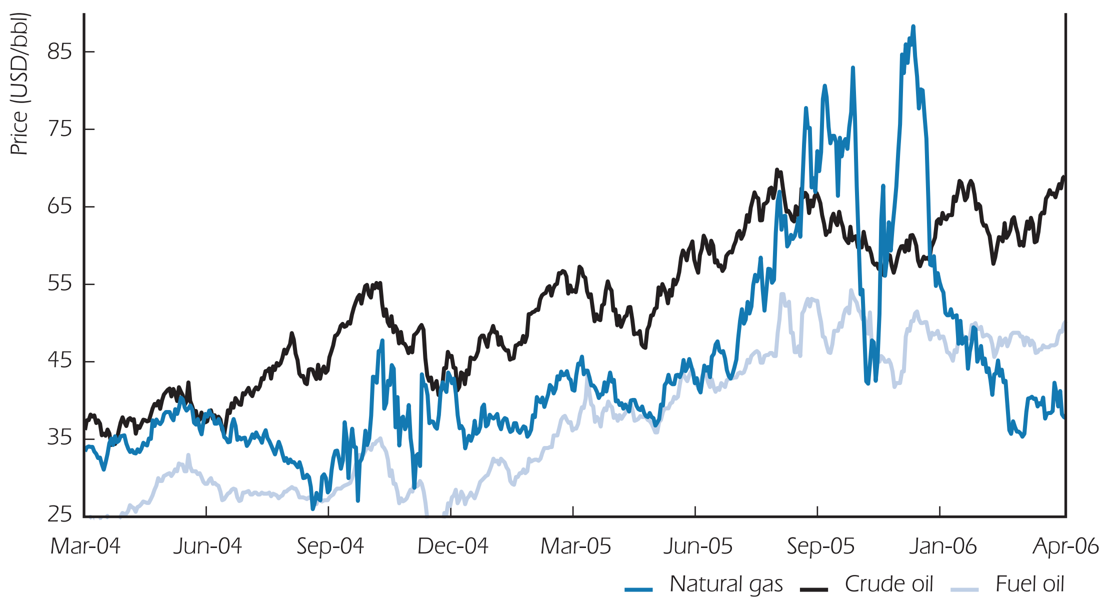
Introduction to price formation

In many areas of the world, gas prices rise and fall broadly in line with oil prices. The historical reason for this linkage is that gas competes in the residential market with gas oil for heating, and in the industrial market with fuel oil for heating and steam generation. Gas contracts used to be negotiated with links to crude oil or oil products in all IEA regions, and this is still the case in IEA Pacific and most of IEA Europe. These contracts take into account the prevailing economics of demand and supply of gas to a limited degree.[11] Although gas is used for similar processes in all major IEA regions, each region has had distinctive price formation processes. These have been largely independent of each other because gas has traditionally not been traded on a global scale, so the regions did not interact.

One of the major links between gas and oil is through short-term competition between them for the same process, so- called fuel switching. Fuel-switching capacities vary between sectors. The residential and commercial sectors are large user of gas, and are regarded as incapable of fuel switching other than over long periods of time, because individuals do not frequently change their home heating systems. Regarding new power plant investment decisions, gas-fired plants are in competition with coal, nuclear and renewables for long-term investment finance. In short-term decision making, they compete with a range of oil products. In the past decade, the increasing use of CCGT plants, some of which can also run on lighter oil distillates, has lead to competition between gas oil and gas in power generation, whereas historically fuel oil was used. This also shifts the balance of back-up fuels away from an almost exclusive use of heavy fuel oil to lighter distillates. In the industrial sector, fuel oil is still the main competitor. High-intensity gas-using sectors, such as chemicals, can and do re-locate to places where gas is cheaper over the long-term, whereas they might modify production rates between locations in the short to medium term.

11. A simple linear relationship would be of the form $Price_{gas} = P_o + (A \times Price_{oil})$ where P_o represents the zero price, and A the gradient. P_o would be expected to be higher in a “sellers’ market” than in a “buyers’ market”. Often, price re-opening clauses allow for modification of these variables every few years or if there have been “significant market changes”.

Figure 31 **Gas competes with a range of oil products, sometimes...**



Aspects of price competition amongst fuels can be illustrated by Figure 31. This shows the traditional competition for the United States' North East heating market over the past 2 years. The daily prices of natural gas (on an oil equivalent base) at Chicago City-gate are compared against the price of New York harbour fuel oil, with the price of West Texas Intermediate (WTI) crude for comparison. In the Figure, from left to right, the gas price seems initially to track WTI and then transitions (over the course of several months) to the level of fuel oil. Chicago City-gate gas prices seem to be supported by fuel oil prices from this point onwards: indeed they trade in a range between fuel oil and WTI over much of the period.

Just before the hurricanes in the United States, gas was trading at approximate crude oil parity. As hurricanes Katrina and Rita hit the gulf, gas prices increased far beyond oil. During the period immediately after the hurricanes, gas was considerably more expensive than fuel oil, and fuel oil use increased. Since late January 2006, gas has even traded below the fuel oil floor due to higher than average gas storage levels and there has been a corresponding decrease in fuel oil demand.

Although the North American market is still regional, one of the most interesting global developments is that it is now starting to interact with other regions through LNG. This is beginning to create influential links between regions and is, therefore, affecting pipeline-gas prices. Although there is not a global gas market as yet, this trend could herald the start of one.

IEA Europe

In European markets (apart from the United Kingdom),[12] the linkage between gas and oil prices is still rigidly formalised by contract, so as oil prices move, gas prices automatically follow. Importantly, price adjustments are averaged over periods of 6 to 9 months, and lagged by 1 to 3 months. This pricing system was developed when gas itself was introduced to these countries some decades ago. This was mainly because those first gas producers had to create a market for gas where none existed, taking market share from oil. It was realised that the gas retail company could control the market share of gas by guaranteeing that gas would be cheaper than the oil that customers were relinquishing. A discount to oil products, over time, resulted in an increased market share for gas; oil parity held that share at a required level. Pricing gas on oil indices thus helped oil-consuming countries to diversify their energy use after the first oil shocks and substitute for gas-oil and heavy fuel oil in the residential/commercial and industrial sectors. Due to different indexation formulae and transportation costs, border prices in continental Europe can differ widely. For example, in September 2005, the import price of Dutch gas to Belgium was estimated at USD 4.78/MBtu, whereas Algerian LNG imports in Belgium averaged USD 8.38/MBtu.

Another factor which argues in favour of oil indexation is that the oil market is already established, with an active liquid futures market allowing hedging of exposure for several years. This means that investors are educated about, and comfortable with, the oil market. Importantly, banks will lend money based on oil revenues. The linear, oil-indexed price is well suited to a stable market environment, but the market is changing. Over time, the substitution price arguments have become less relevant, as gas competes less with oil products in many of its key markets. Increasingly, oil is used for transportation, whereas gas is used for power generation. The growth of gas-fired power generation has provided an opportunity for oil substitution in the short term, but environmental factors again limit the practical availability of fuel switching, except where governments are willing to ease them, as one done in the United Kingdom and Italy in winter 2005-06.

The European gas market is a mature market, and gas is now a valuable commodity in its own right. Indeed, the decreasing competition between oil and gas in Europe may now mean that this pricing system has become a disadvantage to the efficient operation of both gas and, to a certain extent, power markets. Oil indexation does not provide the necessary price information on short-term gas supply or demand in order to allocate the resource efficiently, particularly in dynamic markets.

Winter 2005-06 saw market failures in several European countries, most notably Italy, as the gas price was not able to respond to gas shortages. With high

12. The Hub in United Kingdom (the NBP) sees large quantities of gas delivered against the NBP index. The Netherlands and Belgium are established markets, but not yet liquid enough to be representative of the domestic market. There are nascent Hubs in France, Germany, Austria and Italy.

European power prices, the economic incentive in these circumstances was to generate electricity from gas for export to the European market, whilst other gas users felt no price signals to curb gas demand and only limited signals to augment supply. In consequence, the government intervened to manage demand and maximise supply. In this example, it can be seen that the price of gas did not match supply and demand in oil-indexed markets. Meanwhile, the United Kingdom's interconnector to Belgium operated at well below capacity during the winter despite a persistent and high price differential. There is some debate as to why continental players were not in the position to export more gas to the United Kingdom in the winter, given the extent of the price differentials and also that the United Kingdom's seasonal demand pattern is now fairly well known. The tight situation in Italy necessitated government intervention to manage the situation; the United Kingdom's situation resulted in high, volatile prices. In both cases, these market failures put security of supply in jeopardy.

A more complex argument in favour of direct oil indexation in gas pricing has been that an independent reference point would insulate the gas price from cartel/monopoly behaviour of large upstream players. Clearly, manipulative behaviour is most visible in a market which allows prices to be determined by supply and demand, because cartels operate by restricting one or the other of these variables to impact the price. A counter-argument could be that the more transparent the manipulation, the more easily-diagnosed and dealt withit is, and the less of an overall threat to consumers.

United Kingdom

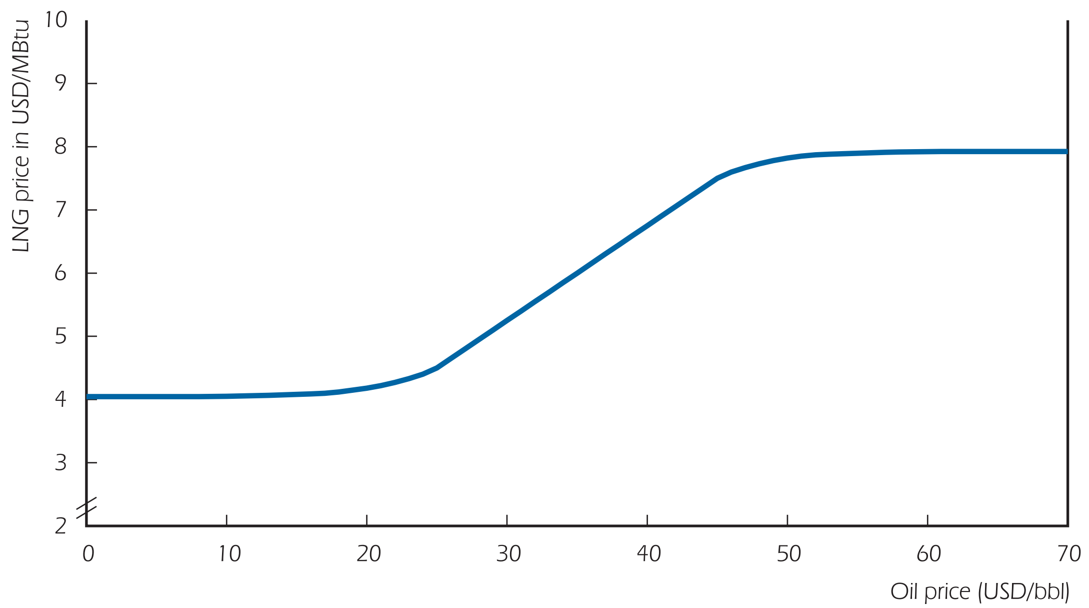
Spot Gas trading is widely developed in the United Kingdom with the virtual National Balancing Point (NBP) as the key trading point in the entry/exit based system. The market has around 80 counter-parties, and gas prices are set by supply and demand to clear the NBP. About half of the gas consumed in the United Kingdom is traded on spot markets, the other half is delivered according to the terms of old North Sea prices, incorporating many indices such as coal, inflation and electricity, but principally fuel oil and gas oil. The International Petroleum Exchange of London (IPE) launched a gas futures contract in 1998 which is liquid for several years into the future. Recent long-term contracts supporting large infrastructure projects have been signed with Norwegian producers and Dutch traders at NBP prices rather than oil prices. The same is true for recent LNG contracts signed between United Kingdom and Qatar.

The United Kingdom is a net importer of gas but it still exports to the continent in the low-priced summer through the IUK Interconnector to Belgium. Although cheaper gas is available in the United Kingdom in summer, there is no impact on continental retail prices because of the lack of competition in the continental European gas market. The United Kingdom's market imports the oil-indexed link to some degree from the continent through the Interconnector despite having only a minority of legacy oil-indexed contracts.

IEA Pacific: Japan and Korea

Japan and Korea have successfully diversified their energy supplies away from oil since the 1960's by using gas as a substitute fuel for power generation and home heating. Since neither country has substantial domestic reserves to rely on, they were only able to access significant quantities of gas by importing it over substantial distances as LNG (e.g., from Alaska or Indonesia). In terms of pricing, both the buyer and the seller agreed to base the price of LNG on oil products, in order to negate the risk of price competition with oil. Because the producing companies and countries in the new business had to make substantial investments in LNG liquefaction trains, a pricing model evolved that provided a floor price. This floor limits the fall in the LNG price to a certain level even if the oil price were to carry on falling – guaranteeing a minimum revenue stream. Conversely, buyers are protected by a price cap, which restricts LNG price rises when oil prices rise above a certain point. In financial markets, this kind of arrangement would be referred to as a "collar". However, rather than acting exactly as a financial collar, the cap and floor were applied gradually, so that the rate of gas price increase with oil slowed down at around USD 35/bbl, but was actually capped at around USD 40/bbl. This arrangement was called the *S curve* from the shape of the oil/LNG price graph (see Figure 32). Over time, the slopes, or rate of change of parts of this curve, have changed, but the basic pattern remains. In common with the European markets, prices are lagged and averaged, but over somewhat shorter periods.

Figure 32 ***Illustrative example of the S curve LNG pricing method***



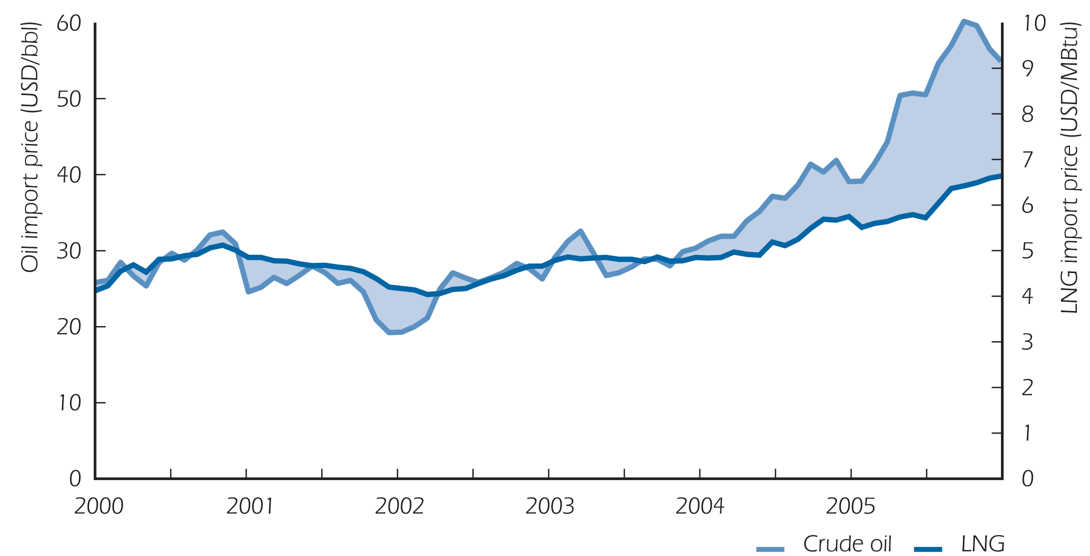
Because the international oil market itself has no caps or floors, this *S curve* imposes some interesting economics on end consumers. It means that gas can be cheaper than oil at high oil prices, and more expensive than oil at low oil prices. In turn, this means that gas automatically gains market share (particularly for industrial users) at high oil prices, and loses market share to oil at low oil prices – these non-linear economics can cause unusual outcomes. One such example is the encouraged use of oil instead of gas when oil prices are low (as gas prices will be higher), unintentionally impacting customer choice. In the current high oil price environment, the major impact is the opposite, encouraging the use of gas capped at a price well below that of oil. Gas utilities are seeing increased demand from this effect, part of which is met by power companies scaling back LNG use in favour of cheaper coal and nuclear generation.

In order to aid the re-distribution of existing LNG within Japan, some of the destination clauses on Japanese cargoes have been negotiated away. However, the extent of the difference in prices between oil and gas has meant that the increase in domestic demand for gas has outstripped the offset from power utilities. This means that gas importers in Japan (and Korea) have been buying from the spot LNG market. Ironically, the prices paid for spot LNG have been substantially higher than oil parity, as high as USD 25/MBtu, in order to re-sell onto the domestic market at around USD 8/MBtu.

IEA Pacific: Australia and New Zealand

Both Australia and New Zealand have small domestic gas markets in absolute size, with gas contributing around 20% of total primary energy supply. These gas markets

Figure 33 **Japanese LNG prices decouple from oil**



are fully liberalised, allowing gas prices to be set by gas supply and demand. While both have domestic reserves of gas, New Zealand is suffering from reserves decline at its major producing field. The markets of both countries are relatively deep and liquid given the market size, and both governments intend to allow companies to solve supply and demand imbalances as they arise or are predicted.

Australia, as a major exporter of LNG, is exposed to the prices in destination markets, but the major export sites are quite remote, and not linked with the domestic grid, so there is little interaction between them.

IEA North America

The North American market is the fusion of the United States' and Canadian regional markets. Up to the early 1980s, both markets operated in a similar manner to the European market of today, with oil-based contracts and pipeline companies who sold gas to customers on a long-term basis.

In the 1980s and 1990s, both markets were liberalised, and network assets were unbundled from other functions. Long-term oil-based contracts were not found to be suitable for the new environment in

Box 4 **How does Hub trading work?**

With transportation systems separated from trading and with multiple suppliers of gas, parties need to co-ordinate with each other in real time. Whilst this process is very complex, pipeline companies set up trading facilities to market their capacity services and gain higher utilisation factors for their pipelines. They, therefore, have to make as much information available to gas traders as possible. These services were aggregated around nodes in the transmission network, or Hubs.

As IT services develop, more information about the demand and supply of gas is available and the marketing process is more efficient, being balanced every day. Thus the price of gas becomes a very good indicator of the supply and demand situation in real time. The differences between prices at two points in the system (known as the basis) are a good indicator of the need for new pipeline infrastructure. Demand for balancing services in a volatile market is seen by gas customers as a signal for more investment in storage. Infrastructure builders in North America respond to demand for new facilities using an open season, a time period during which shippers may register their interest in leasing the facility if it is to be built.

The Hub system has spread across North America, and gas is now traded at over 40 principal centres across the North American continent; the best-known is Henry Hub in Louisiana, at the junction of 14 inter-state pipelines and close to production fields and storage. Henry Hub is also the reference point for pricing of gas for the NYMEX gas futures contract.

which gas flows were optimised between different parties. Instead, gas pricing was based on the fundamentals of supply and demand at a given time and place. As can be seen from the graph of United States' prices in Figure 31, gas prices sometimes track oil products, but not necessarily. There are periods of time when gas seems to be in direct price competition with fuel oil or WTI, but there are periods where the price is transitioning between these levels. The average WTI price in 2005 was USD 56.70/bbl, whereas the average Henry Hub price was USD 53.59/bbl (like-for-like base). Average prices for any given year might be similar to average prices for oil products on a like-for-like basis, but this is too simplistic, given the dynamics of the market as explained in the previous Section.

Following the change of pricing from oil linkage, the market in the 1990s was characterised as a gas bubble. This period was defined by surplus gas deliverability at the wellhead when oil indexed gas prices were much higher. With the market encouraging balancing, there was no incentive for overinvestment, and this surplus has since disappeared with the erosion in supply capacity. North America has since been moving from a period of low-cost domestic gas supplies in the 1990s (around USD 2/MBtu) and has since then steadily increased. The United States market is anticipated to require more imports, as domestic gas has become harder to find and more expensive to produce Coal bed methane was regarded as a frontier technology only 10 years ago, today it is a major source of United States' gas production.

End-consumers in North America have a range of pricing options available to them. It is possible for an industrial consumer to sign a supply contract at a fixed price,[13] at daily spot prices, or, e.g., a monthly index. Some consumers index their gas purchases to power prices, coal prices, or whatever is suitable for their business, including oil prices.

When gas fundamentals determine value, rather than only oil markets, other factors are taken into account in price formation. In the North American markets, the price of gas at any time is also likely to contain *inter alia* information on power plant availability, hydro levels, gas storage levels, oil product prices, pipeline use and availability, temperature, and the level of industrial demand.

The fundamentals of gas supply and demand are complex and variable which is why the spot price is volatile. This volatility can either be mitigated by demand and supply management, or acts as a signal for investment by allowing a financial return for short-term storage. In turn, the action of storage on the market helps decrease volatility. From the perspective of the end-consumer, the volatility can be managed by fixing prices over a longer term, or by actively participating in the spot market.

13. Players in the North American market seem to prefer relatively short-term fixed price deals, of around one to two years (as can be seen from the liquidity of the NYMEX forward market).

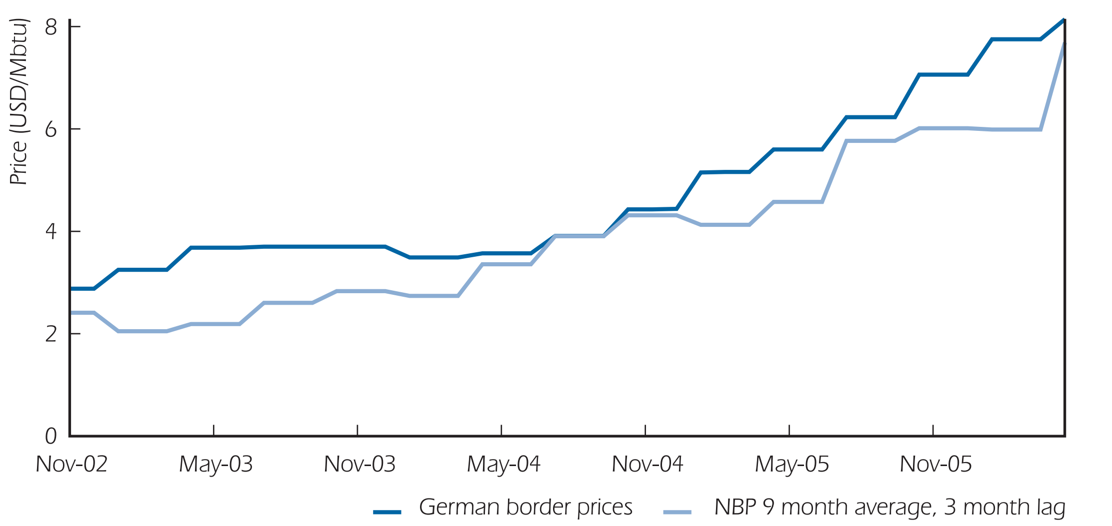
Price volatility

There is an argument that liberalised gas markets result in gas price competition, leading to considerably more volatile prices than in oil-based gas markets. It is implied that liberalising the gas markets is, therefore, worse for consumers. The fact is that most oil-based gas contracts carry an averaging period, which smoothes the price volatility over several months. Customers, perhaps without knowing it, are actually exposed to spot oil markets. In Germany, for example, it is the spot prices of fuel oil and gas oil which comprise the indexation and, therefore, determine the periodical movement in gas prices. The oil-to-gas formula smoothes the oil price volatility by averaging the commodities over 6 or 9 months, and then waiting 3 months to change the gas price. This leads to less frequent price changes and, therefore, low volatility.

The same type of formula could be applied to spot natural gas prices instead of oil prices to achieve a less volatile index. For example, the United Kingdom's NBP spot price could also be averaged over 9 months and lagged by 3 months, as shown below. It is interesting to note that had a company in the United Kingdom signed a gas contract with such an NBP formula, it would have been paying lower prices than a similar German company since before 2002.[14] (Note that *delivered* German prices will be higher than border prices).

So the major barrier to gas pricing is in creating an appropriate gas index. This is a more substantial challenge in Japan and

Figure 34 **Averaging spot prices removes volatility**



Source: IEA and World Gas Intelligence

14. It should also be remembered that the full effects of record United Kingdom's gas prices in the winter 2005-06 are not yet reflected in the graph above, nor are the effects of high world oil prices in the same period.

Korea than in IEA Europe because there is less physical interconnection between countries in the Pacific, and there is no trunk pipeline system in Japan. As has been seen in Spain, however, the means exists to achieve gas indices through offshore LNG trade, as the spanish experience demonstrates.

Supply response to gas prices

Gas supplies inn 2006 are tight in the major markets, whether this is in the LNG markets, where there is a lack of spare liquefaction capacity, or in pipeline markets. Evidence for the latter can be seen in both major pipeline markets: in the North American market, the price is a strong indicator of the tightness, and in the European market, several countries have found that they are not able to increase their imports on demand as they used to.

Most long-term supply deals seen in the Pacific and European markets have built-in flexibility. This is no longer required in the North American market, as consumers can always buy more gas at a Hub.

Most LNG trains are contracted below their actual maximum production, and, therefore, can produce gas to be sold to the highest bidder – on the spot market.

The market has traditionally sought supply response through spare capacity on import pipelines, notably swing supplies from Russia (see Russia Section). The European market has been designed to operate on contracts with a minimum purchase per day and per year from a supplier, but with a customer's option to increase that volume on demand to a maximum. This contract format is called a take-or-pay contract.

Demand response to gas prices

Over time, all gas consumers react to gas price movements. As prices in North America have risen steadily over the past six years, there has been a strong tendency to lower ammonia and methanol output, and switch production to sites near cheap sources of gas. As oil prices have risen, many industrial users in Japan and Korea have switched fuel use away from oil products and towards natural gas.

It is over the short term that the large difference can be seen between oil-indexed and gas fundamentals-based pricing. In a supply crisis, North American customers would see a gas-price spike, as happened after hurricanes Rita, Katrina and Wilma in 2005. In a similar situation, in Japan or Korea, gas prices would be unaffected, as in most of Europe. The automatic response in the North American market is for low-value added users to decrease consumption for a period. If they are buying spot gas, the price becomes too expensive; if they buy fixed-price gas, they may be in a position to sell the gas onto the market for a profit and interrupt own consumption. The price signal increases supply, and higher-value consumers continue to have their demand met. Conversely, in markets relying on oil indexation, gas prices do not reflect underlying gas supply issues and, therefore, cannot illicit a demand response from the market.

A new challenge is posed by the increasing use of gas-fired power generation in IEA countries, in turn linked to more flexible electricity markets. This trend is being driven by many different factors (see Gas for Power Generation Section) one of which is increased flexible generation which follows increasingly variable power demand. When electricity demand spikes (usually in particularly cold or hot weather), gas-fired generation is increasingly used to satisfy the demand. This puts extra pressure on gas markets to react quickly either producing more from gas storage/fields or by driving a demand response from other gas-consuming sectors of the economy. This effect can be seen in liberalised markets in the volatility of the gas price. It is being addressed by the construction of short-term storage able to quickly respond to that demand, and by doing so, dampen volatility.

Governments and policy makers are increasingly aware that these market signals should be visible and transparent. There remain substantial challenges to ensure that these demand supply imbalances are able to be accurately predicted by the industry with enough time to ensure adequate supply, bearing in mind that the lead time to construction for new gas assets is relatively long compared with other industries. Where there is little day-to-day demand participation in the gas market, governments and gas companies are working together to avoid the problem of shortfalls which might occur at times of peak demand.

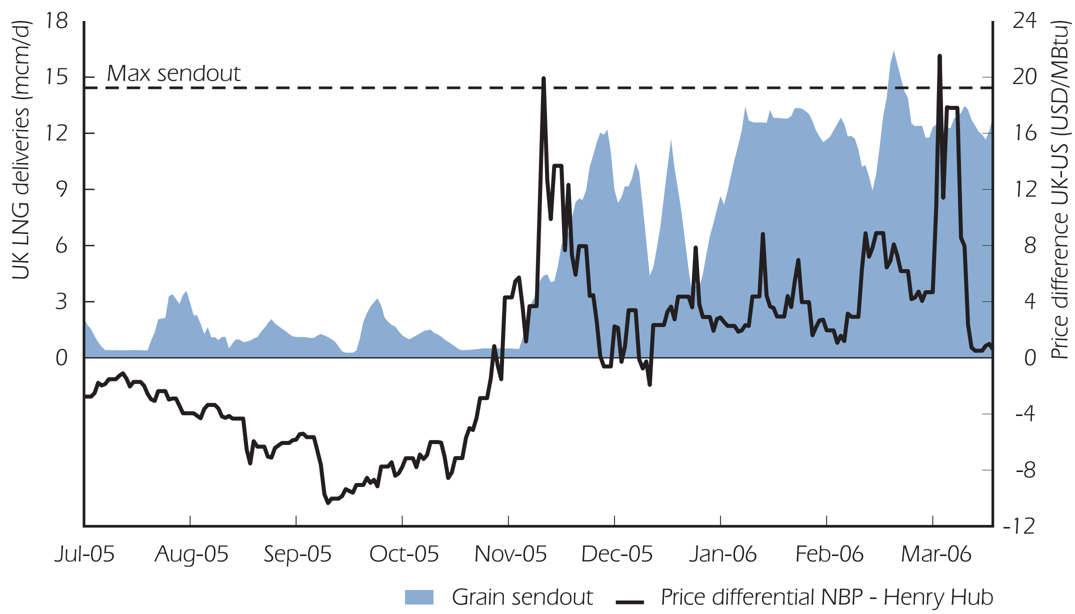
This job is getting ever more complex given the different interrelationships between fuel types, in particular for Europe, and new flows of energy across borders. This means that the availability of timely, accurate and transparent data is becoming a critical issue for suppliers and consumers, and their respective policy makers.

Price convergence between the regions

Whether liquefied or not, natural gas is much more difficult and costly to move from one region to another than oil, although the situation is improving, as both absolute and relative costs of transportation are lower than 10 years ago. The emerging trend is, therefore, one where prices in one region will influence prices in other regions through new opportunities for trade. Arbitrage possibilities sometimes exist between the various mature markets through diversion of LNG cargoes, or through pipeline/LNG swaps. Where these deals are arranged, pricing signals from one market are directly transferred to another, meaning that the price differential affects the demand/supply balance in both regions, an essential factor to bear in mind in market design.

In the case of the United Kingdom and United States, this effect can be seen clearly. Figure 35 shows the send-out from the United Kingdom's LNG terminal at Isle of Grain (on the left-hand axis) compared with the price differential between the United States' Henry Hub and the United Kingdom's NBP over the same period, since the United Kingdom started importing LNG in July 2005. Despite the multitude of other influences on the movement of LNG during that period, it can be seen that the

Figure 35 **Arbitrage in the Atlantic Basin**



Source: National Grid

deliveries of LNG to Grain have followed the United States'/United Kingdom's price difference, as would be predicted in theory; where the United Kingdom's price is higher than the United States' price, cargoes are delivered to the United Kingdom.

In many other situations, similar diversion deals are put together. However, the nature of oil indexed markets makes this difficult to see. The price differential between these markets does not fully explain the diversion of cargoes, even though there must be some incentive for the transaction. One example might be the Spanish/United States' LNG arbitrage, where the regulated price of Spanish gas is a poor indicator of the supply/demand balance. Using this price as the Spanish gas price, an observer would have struggled to explain why, during 2005 and 2006 many spot LNG cargoes have been attracted to Spain rather than the United States – despite more attractive Henry Hub prices. In fact, spot LNG cargoes have been sold to Spain on Spanish power indices, allowing the more nimble Spanish power market to attract cargoes away from the United States, and thereby bypassing the relatively unresponsive gas market. For this to continue in the absence of further gas market development, gas companies need to have a strong presence in the power market.

Where large gas companies are able to make enough profit on their core, long-term contract business, they can import spot LNG cargoes for their consumers despite making a loss on the individual delivery.

This explains the instances of Japanese and French buyers paying over USD 20/MBtu for cargoes to sell onto their domestic market for less than USD 8/MBtu.

These examples highlight that the globalisation of the gas market is starting. The rise of pricing markers which cross borders over the other gas regions (such as Henry Hub in Asia, or Spanish electricity in the Atlantic basin) point to an interesting trend of flexibility of reference points.

While the North American market is predominantly based on pipeline gas, and the Pacific market is predominantly based on LNG, it is in the European market where there will be the most interaction between LNG and pipeline gas. There is a small but growing influence of such developments on pipeline gas markets, hitherto also heavily regionalised.

The consequences of these new links are that gas markets are no longer isolated and events in one region will have an impact – to varying extents – on other regions. The gas market is not yet global but policy makers and other stakeholders can no longer ignore what is happening in the other regional markets.

REGULATION

High prices have encouraged governments to consider new policies for exploring and producing gas in areas of hydrocarbon wealth.

The North American, Australian, United Kingdom's and New Zealand's experience tells us that regulation is dynamic even when a solid market structure is in place.

The OECD European area is in the process of liberalising its markets, but major weaknesses remain, including market concentration and lack of transparency.

Japan and Korea are adopting a measured attitude towards liberalisation commensurate with their traditional gas market focus on security of supply.

Policies to encourage upstream investment in certain non-OECD countries have been very successful.

Introduction

Certain aspects of the gas industry have attracted regulatory attention, especially the monopoly aspects, such as pipeline systems. Given the long financial cycles of the industry, it is particularly vulnerable to regulatory changes which can be a source of risk and, therefore, cost. Such uncertainty can undermine investment.

However, although stability is desirable, regulatory change is essential for the continued adaptation of markets in the light of external changes, e.g., to the global economy. That which has remained constant is a commitment by IEA countries to a common energy strategy based around the three pillars of economic growth, energy security and environmental sustainability.

IEA countries have stated that, in formulating energy policies "the establishment of free and open markets is a fundamental point of departure". In order to reconcile a consistent energy policy with a commitment to markets, regulation must evolve to ensure that markets deliver long-term energy strategies. A good example of adaptive energy regulation can be seen in the United States gas market, which has a long tradition of relying on iterative methods in regulation. The EU is in the process of liberalising its gas markets. The IEA Pacific region includes the fully liberalised Australian and New Zealand's markets, and the gas industries in Japan and Korea, also moving towards liberalisation. Liberalised markets require the role of governments to be redefined. It does not mean there is no role for governments.

Policies to encourage resource development

Given the increase in gas prices in OECD regions, 2004-06 has seen unprecedented interest from the hydrocarbon industry in gaining access to new oil and gas reserves and resources (as well as increasing production and recovery rates). In OECD countries, monetising gas reserves usually involves high-cost and technically-challenging projects, e.g., deep water long-distance pipelines or unconventional gas deposits. This has resulted in government efforts to encourage investment in unconventional gas resources and to encourage the building of pipelines to link these reserves to markets.

Examples can be seen in the United States (Alaskan North Slope) and Canada (MacKenzie River), as well as in Norway and the United Kingdom (North Sea Continental Shelf).

In North America, drilling in the Arctic National Wildlife Refuge (ANWR) and in offshore areas (the Outer Continental Shelf – OCS) is so far excluded from Exploration and Production activities. These regions are potentially an important part of gas supply, as ANWR and the OCS include large resources of hydrocarbons.

In Canada, oil producers have been attracted to Alberta's oil sands as an economic source of heavy crude, particularly due to cost savings in the mining process in recent years coupled with the continuing high crude prices. Since processing the oil sands consumes large volumes of gas, the Canadian government has started to look at new sources of gas by encouraging drilling offshore and by facilitating the building of a pipeline from proven reserves in the North West to the market.

Norway has also taken steps to increase production in its waters, given recent signs that the Norwegian Continental Shelf is also reaching maturity. In response, the latest licensing round offered an increased number of blocks, some of which were located in the Barents Sea – a site of great untapped wealth in hydrocarbon deposits, but which faces particular environmental issues.

Furthermore, stranded gas fields located in areas of disputed nationality have stimulated much interest from governments keen to realise their development. Negotiations between Australia and East Timor have opened the path to enable gas projects in the East Timor Sea to proceed. The United Kingdom and Norway have also recently concluded a framework to develop hydrocarbon reserves which sit astride their territories.

In non-OECD countries (where 90% of world gas reserves are found), domestic policies to open up access for foreign capital ase also of considerable importance. For example, Algeria and, to a greater extent, Qatar have achieved considerable progress in resource development by means of policies aimed at deregulating and opening up their upstream sectors to investment. These developments are discussed elsewhere in this review.

Liberalisation of markets

Over the past five years, there has been a general trend – and acceleration in Europe – to further liberalise the gas markets across the OECD regions and in OECD countries, and this trend is spreading to countries outside the OECD regions.

OECD Pacific

The Australian federal government in concert with the states has recently established a single national energy regulator, covering both electricity and gas, and replacing at least thirteen provincial bodies regulating these areas.

In Japan, the government is aiming to balance maintaining gas supply security with enhancing the competitiveness of the gas utilities. It intends to gradually expand the scope of retail liberalisation to consumers with an annual demand of at least 100 000 cubic meters in 2007, or about 50% of the gas demand. To ensure fair and transparent third-party access to pipelines, the government proposes accounting separation and information firewalls between transportation activities and other activities of gas companies. Since negotiated TPA to re-gasification terminals was introduced in 2003, owners of LNG import facilities have been required to publish the amount of surplus capacity at their terminals, and give reasons for denying access to third parties who want to use that capacity.

The Korean government signalled in 1999 that it was keen for competition to develop in the gas sector, and has since proposed that the Korean gas company (Kogas) provide TPA to all gas infrastructure. In July 2005, POSCO (the Korean steel company) commissioned the first privately built re-gasification terminal at Gwangyang.

OECD Europe

Europe is in the process of reform which was started in the EU with the adoption of the EC Directives (passed in 1998 and 2003) on the internal gas market. The second Directive (EC/2003/55) entered into force in July 2004. The aim of the new gas Directive is to accelerate market opening, create a more consistent regulatory framework for the EU Member States, and increase the level of integration among the individual markets.

The Directive includes the following key provisions:

- Full market opening for all non-household customers by July 1 2004 and for all customers by July 1 2007.
- Legal unbundling of transmission and large and medium-sized distribution companies.
- Third party access to transmission and distribution networks on the basis of regulated tariffs.
- Access to gas storage facilities either on a negotiated or regulated basis.
- Strengthening of public service obligations especially for vulnerable customers.
- Monitoring of security of supply.
- The establishment of a regulatory authority in each Member State with a common minimum set of responsibilities.

Reflecting a marked increase in the amount of resources being directed towards gas market liberalisation by the EC, the Directorate General for Competition (DG-Comp) also launched an investigation into the gas market which reported in November 2005. This investigation provided another clear analysis of the weaknesses of the current situation, stating that the European gas landscape was suffering from: market concentration, vertical foreclosure, insufficient market integration, lack of transparency and a lack of market-based prices.

In April 2006 the Director General for Energy and Transport put 17 member governments[15] on formal notice for

15. Austria, Belgium, the Czech Republic, Germany, Estonia, Spain, Finland, France, Greece, Ireland, Italy, Lithuania, Latvia, Poland, Sweden, Slovakia and the United Kingdom.

failing to implement various aspects of the European Union gas and electricity directives. A number of issues were cited, including the lack of legal unbundling of gas transmission and system operators, lack of true third-party access and insufficiently transparent gas tariffs.

Recent large-scale merger activity in Europe stresses the importance of a continued development of the internal EU energy market where competition can flourish in a fully transparent market, and where gas can move easily and efficiently across borders to bring greater collective security. Further development of a regulatory framework that allows for effective competition is critical, as has been highlighted by the Commission early in 2006.

OECD North America

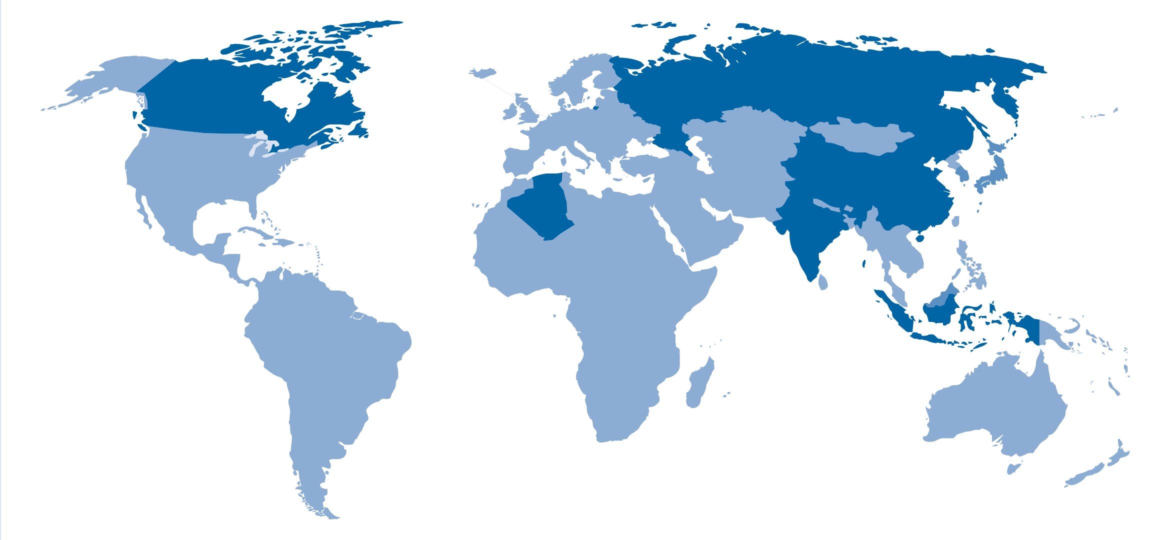
The North American gas industry has undergone profound structural changes over the last three decades, largely due to regulatory reforms aimed at promoting competition and improving efficiency. The North American wholesale market for gas is highly competitive. Thousands of producers, independent marketers, pipeline affiliates, local distribution companies (LDCs) and end users compete to buy and sell gas at the wellhead and at Hubs located across the region.

Recognising that gas supplies have recently been tight, the United States' government is promoting the import of LNG. It has moved quickly to encourage the construction of LNG terminals by adopting regulation and streamlining the authorisation process. Major changes to the regulation of offshore terminals were adopted in 2002 to facilitate the construction of LNG facilities, including the placing of offshore terminals under exclusive Coast Guard jurisdiction and exempting owners of offshore LNG facilities from open access provisions. These moves granted owners the right to reserve for themselves all of the import and storage capacity at their facilities (proprietary access), and preceded a similar decision on onshore LNG facilities.

In August 2005, the president of the United States signed the Energy Policy Act which gave FERC exclusive jurisdiction for the location, construction, expansion or operation of LNG terminals, but prevented open access requirements or the possibility of regulation until January 2015. This effectively codified FERC's earlier decision of 2002 (the Hackberry decision), designed to facilitate investment in LNG import terminals. It also moved to accelerate the administrative process by allowing a pre-filing process for LNG terminals. This procedure means that FERC is involved in LNG projects before they are formally submitted, so it can help companies to better prepare their application. In addition, Section 312 of the new Act is designed to encourage investment in new gas storage facilities, seen as an essential adjunct to increasing imports. Under the Section, FERC is able to allow a company to provide storage services at market-based rates, even without the obligation to demonstrate the lack of market power.

INDIVIDUAL COUNTRY FOCUS

Figure 36 **Highlighting individual countries**



Introduction

In this Section, six countries are highlighted, which are of particular interest to global gas supply and demand. Canada is currently a large exporter to the United States but its volumes are projected to decrease, meaning that North America will become more reliant on LNG. Russia and Algeria are the most important suppliers to Europe. Russia also holds the world's largest gas reserves and intends to supply gas to Asia and the United States in the future. Algeria already supplies gas to the United States in the form of LNG. Indonesia is a large supplier of gas in the form of LNG to Japan, Korea and Taiwan, but has not been able to maintain maximum production rates, meaning that customers had to source LNG from other countries, thereby affecting the global LNG supply and demand balance. India and China are emerging economies and show enormous latent potential for gas demand. Both countries are interested in LNG supplies and could, therefore, potentially affect the global LNG balance.

Canada

Canada's gas production will plateau over the next five years, but domestic demand is increasing meaning net exports to the United States will decrease. The rate of decrease depends on the interaction of several factors, including the growth of coal bed methane production, northern and offshore gas developments, the strength of oil sands gas demand and construction and use of gas-fired power generation.

LNG will become more important in North America, which will link Canadian markets to world markets and vice versa.

Competitive markets ensure that demand balances supply in the North American gas market. High prices encourage supply and investment, reduce demand and attract imports.

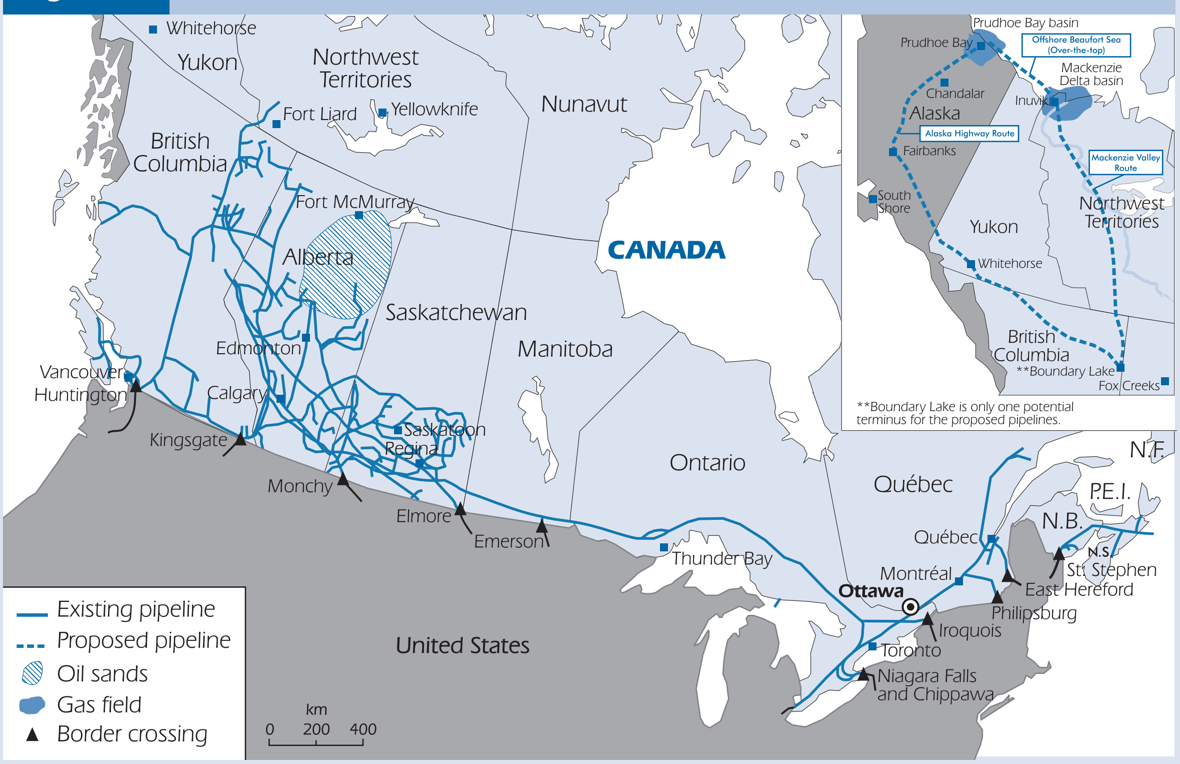
Introduction

Canada plays a significant role in the North American natural gas market, providing about one quarter of the combined natural gas production of Canada and the United States. Over the past 25 years, Canada has raised its market share of the United States' gas consumption from 5% to 15%. The province of Alberta in western Canada accounts for nearly 80% of total Canadian gas production. From 2000, annual gas production in Canada has hovered around 184 bcm (6.5 tcf). Canada exports a little over half of its gas production to the United States through pipelines that are integrated with the United States' interstate pipeline system.

Production

Higher natural gas prices led to record drilling in Canada in 2004, with 15 627 gas wells drilled during the year. Drilling yielded a significant gas discovery by Shell in the Alberta Foothills and another by Talisman in north eastern British Columbia. Nevertheless, since 2000, Canadian natural gas production has slowed or declined, reflecting to a large extent the maturation of the Western Canadian Sedimentary Basin and faster-than expected decline in gas resources from the Sable Offshore Energy Project on the East Coast. Increased drilling and the rise in production of coal bed methane will sustain gas production in the coming years. CBM production at year

Figure 37 Canada



end 2004 was approximately 3.5 mcm/d (125 mcf/d). While this was less than 1% of total production, CBM is expected to become increasingly important to the Canadian natural gas production mix. CBM is forecasted to grow about 50% per year. Over the longer term, forecasted declines in conventional natural gas production will largely have to be offset by Western Canada unconventional gas production, Mackenzie Delta, and LNG imports.

In response to the need for increased gas supply in Canada, the Mackenzie Gas Project proponents led by Imperial Oil filed applications for regulatory approvals in October 2004. The project would involve the development of an estimated 170 bcm (6 tcf) of gas resources in the Mackenzie Delta, a gas-gathering system, a processing facility, a natural gas liquids line, as well as a 1220 km pipeline to bring northern natural gas to markets in the south. Public hearings on the Mackenzie Valley pipeline, which has an initial design capacity of 34 mcm/d (1.2 bcf/d) and operation planned to start by 2011, began earlier this year.

Development of the Mackenzie gas project has required significant co-ordination and cooperation between the federal-territorial governments, industry and the population in the North. The Aboriginal Pipeline Group (APG) was formed to enable ownership interest of the Aboriginal peoples of the Northwest Territories in the proposed natural gas pipeline. TransCanada Pipelines Limited helped to finance APG's ownership.

Demand

Canadian gas demand can be impacted by many factors, including weather conditions, developments in the power sector, as well as in the oil sands industry. In spite of an oil sands-related increase in demand in western Canada, Canadian natural gas demand declined by almost 4% in 2004 to 90 bcm, due mainly to reduction in core and industrial sectors in Eastern Canada. For the period 2003-10, demand for natural gas is expected to rise by 5% annualy, driven by 17% power generation and industry sector.

Natural gas is increasingly used by the oil sands industry in Canada. A large part of the energy requirements for oil sands mining, extraction and upgrading operations, as well as for *in situ* operations, is met through on-site electricity generation using natural gas as fuel. Mining requires energy for the operation of the equipment, such as electric power shovels used to remove and recover oil sands from the mine face, and the operation of the facilities that move the oil sands in a water-based slurry to the bitumen extraction sites. Current extraction processes use natural gas as a source of heat in a hot water extraction process that separates the bitumen from the oil sands. Upgrading bitumen into higher-quality synthetic crude oil utilises natural gas as a source of heat and steam for processing, and also as a source of hydrogen for hydro-cracking and hydro treating.

The Canadian oil sands industry which currently produces just over one million barrels a day uses about 23 mcm/d (0.8 bcf/d) of natural gas, or 5% of Canadian natural gas consumption. Oil sands based production is expected to reach 2 million barrels by 2010, leading to further increases in gas demand.

In situ production is typically more energy intensive than mining and upgrading. As a result, natural gas costs can be as much as 60% of total operating costs for *in situ* projects. For integrated mining operators it is about 15%. Thus, gas supply and its impact on gas prices is a critical issue to the oil sands industry.

Historically, low-cost natural gas has provided a reliable and relatively clean-burning source of energy, and the oil sands industry has grown dependent on it. More recently, higher and more volatile gas prices have caused oil sands producers to examine alternative energy sources. To reduce exposure to gas prices, oil sands operators are actively seeking ways to further increase energy efficiency and researching and developing alternative sources of energy.

The proposed Nexen/OPTI project at Long Lake is designed to produce a synthetic gas through a process that gasifies the asphaltenes contained in the bitumen, thus eliminating the need for natural gas; Suncor has built in the ability to switch to burning diesel fuel instead of natural gas at its Firebag SAGD project; and Atomic Energy Canada Ltd. has proposed the use of an Advanced CANDU nuclear reactor to produce electricity, steam and hydrogen.

With significant coal resources in the province, the Alberta government may support more use of coal for oil sands development. Coal combustion, which involves the burning of pulverised coal in boilers, is a proven technology and could be considered as a near-term option. However, its use would increase greenhouse gas emissions and also require de-sulphurisation and removal of particulate matter. While coal can potentially provide a long-term, stable source of fuel, the economics and environmental performance of its application in the oil sands remain to be assessed.

Gas constitutes a relatively small share of electricity generation, less than 6% in 2003, or about 10 bcm. Hydro and coal dominate the power sector. The share of gas in power generation is projected to grow to nearly 14% by 2010 (25-30 bcm) and to continue to increase its share beyond that time.

Gas export and import

Natural gas exports from Canada comprised approximately 85% of total United States' gas imports in 2004, or about 15% of United States' gas consumption, demonstrating the importance of Canadian natural gas to meeting United States' gas demand. The United States' midwest and northeast regions historically receive the greatest portion of Canadian exports. Although small, Canadian gas imports have trended upward in recent years, reaching 11 bcm in 2004. Due to increasing domestic demand and plateauing domestic production levels, net exports to the United States are expected to decrease over the coming years.

Liquefied natural gas from outside the region is providing North America with a stronger connection to the global gas market. About 2% of North American gas demand is met by LNG imports. Currently, there are eight proposals to build LNG import facilities in

Canada, six in Eastern Canada and two on the West Coast. Most of these projects target both the domestic and export markets and, therefore, may affect future trends in Canada/US natural gas trade. The most advanced proposals appear to be Irving Oil and Repsol's project in Canaport (New Brunswick), and Anadarko Petroleum's Bear Head LNG project at Point Tupper (Nova Scotia). Both projects have received regulatory approvals on environmental matters. The construction of the Bear Head terminal has been rescheduled and construction of the Canaport terminal has not started yet. PetroCanada has started to investigate the possibilities to bring Russian LNG to the Canadian market, but this is not likely to happen before 2010 and more likely thereafter.

Russia

Russia holds 26% of global gas reserves. Low domestic prices underpin domestic consumption of around 430 bcm, while high revenues encourage pipeline exports of nearly 195 bcm, including 22% of OECD European consumption.

Declining production of the super-giant Medvezhye, Yamburg and Urengoy gas fields are currently being made up for by the Zapolyarnoye gas field and Turkmen gas. These can be considered as the last cheap Eurasian gas.

Development of new fields will be more expensive than in the past and has to coincide with major extensions and refurbishments of transport infrastructure.

The strategy of the major Russian gas producer Gazprom seems to focus more on other priorities than the development of its own reserves, which is a concern to the medium- and long-term deliverability of gas for both growing domestic needs and exports.

Independent producers, already important, are planned to play an increasing role in Russian gas production; although such producers are willing to invest in the Russian gas sector, access to the gas transmission system, inability to export and domestic price controls are constraining activity in exploration and development.

Consumption and exports

Russia's gas resources are vast – some 47 tcm of proven reserves, representing 26% of the world's total. Based on these reserves and its history, Russia is the world's largest producer and exporter of natural gas and has become a large gas user in its own right. Domestic consumption in 2003 was 417 bcm, second only to that of the United States. Gas prices are generally below USD 1.5/MBtu, leading to extensive use in the residential and industrial sectors. Power generation accounts for 40% of Russian gas consumption and provides 48% of Russian power. Approximately 80 % of generating capacity in the western part of Russia is gas-based.

For well over two decades, Russia has been a major supplier of gas to most European countries, through pipelines which transit the Ukraine (covering about 80% of exports) and Belarus, and directly to Turkey (14 bcm in 2004) and Finland. In 2004, gas exports totalled 140 bcm to Western Europe, with an additional 52.5 bcm to Former Soviet Union countries. Some European countries are very dependent on Russian gas supplies, for example, Hungary which receives about three-quarters of its gas from Russia, either directly or indirectly. Even such large gas users as Germany and Italy are respectively 40% and 25% dependent on Russia for their gas supplies.

Over the period to 2010, Russian domestic demand is projected to grow to around 460 bcm. Recent announcements of Gazprom, responsible for Russian pipeline gas exports, suggest that exports to Western Europe will increase to around 180-190 bcm over the next decade. The Sakhalin-2 LNG project (see Investment in the Gas Sector Section) will allow exports in the form of LNG to Japan and the United States, and more LNG projects are planned. Recently, 'Russian' gas was delivered via LNG/pipeline swaps to both the United States and the United Kingdom. The North European Gas Pipeline will be a new export route for Russian gas deliveries to Europe. Plans are under discussion for Russian gas to be exported to China, although these are unlikely to bear fruit until well after 2010, since commercial sales agreements have yet to be concluded and pipelines to be built.

Production

One outstanding structural feature of the Russian gas sector is the dominance of the majority state-owned company

Figure 38 Russia

Gazprom. Gazprom holds licenses to fields accounting for 55% of Russia's reserves; 28% are held by other producers with the remaining 17% unallocated. In addition, Gazprom also owns and operates the mainline gas transmission system, and has the monopoly over gas export. With production estimated at 547 bcm in 2005, Gazprom is easily the world's largest gas production company. This degree of concentration is high and creates competition issues in Russian gas policy. Market valuations of Gazprom place it as one of the largest companies in the world. 33 Independent gas producers (including oil companies) produced an additional 94 bcm in 2005.

Three-quarters of Russian gas reserves and a similar share of current production are located in western Siberia. Some 47% of Russian gas production (55% of Gazprom production) comes from three super-giant fields that have been in production for many years and are now in decline: Medvezhye, Yamburg and Urengoy. Gazprom's fourth super-giant field, Zapolyarnoye, started production in 2001 and reached its plateau production of around 100 bcm per year in 2005. The decline in Russia's existing production capacity is estimated at 20-35 bcm per year.

Zapolyarnoye is considered the last relatively cheap gas in Russia. Much of Gazprom's output costs about USD 0.3/MBtu. The Russian Energy Strategy presents estimates for development costs of the next group of large fields in north western Siberia, the Yamal fields, in the order of USD 0.9/MBtu, excluding investments needed for the related refurbishments and transportation infrastructure this project will demand. It is unclear how and when Gazprom intends to develop the Yamal fields but it is unlikely that they will produce gas by 2010. As supervisor of the development of East Siberia and the Far East, Gazprom is positioning itself to take part in any natural gas development in the region to ensure its control of export routes and volumes.

The role of Central Asia in the Russian gas balance

Another important aspect of Gazprom strategy is its apparent focus on Central Asian gas reserves, relative to that of developing its own reserves or that of Russian independent gas producers. Since early 2003, Gazprom's strategy to engage Central Asian states raises concern about Gazprom's approach to increasing production from its own reserves. Gazprom has contracted up to 80-90 bcm per year of imports from Turkmenistan by 2009. While there is a certain logic in this approach given the proximity of Turkmenistan to major existing infrastructure, there is reason to question the advisability of relying on long-term contracts between Russia and Turkmenistan to meet future growth in Russian and European gas demand. This is especially a concern after the recent increase in import prices Turkmenistan imposed on Ukraine, and the issue of price between Turkmenistan and Russia on increasing imports after January 2006.

Adding to the uncertainty, there appears to have been little investment in refurbishment of the Turkmen part of the Central Asia-Center (CAC) pipeline infrastructure or upstream gas facilities there, whether by Gazprom or other parties over the past years. The pipeline network is made up of five different lines, designed and built over the period 1966-1987, with an overall capacity of about 90 bcm per year, though most independent estimates today put the pipeline capacity at closer to 50 bcm per year. Given that Russia projects increasing Turkmen exports to 80 bcm per year, plus the expected increase in exports from Kazakhstan to 15 bcm and Uzbekistan to 10 bcm, major refurbishment and expansion of the CAC system will be necessary. Four lines of the system pass through Uzbekistan with the fifth branch through Kazakhstan. Refurbishing the Kazakh part of the system is estimated by KazTransGas to cost over USD 2 billion, while Uzbekistan estimates investments needed for refurbishment of its lines at a similar amount. The Turkmenistan government estimates the cost of refurbishment at about USD 1 billion. With Russian work, total investment needs are thus over USD 6 billion and work can be expected to require about four years to complete. However, as the start date of major mid-stream refurbishment and expansion is delayed, so is the end date and the ability of this system to carry the projected higher import volumes to secure Russian and European needs. Although Gazprom describes certain work it has accomplished in some detail, such as Blue Stream and its plans for the NEGP, little information on improving the CAC can be found in its annual reports.

Transparency and focus

Concerns exist that Gazprom may not be investing adequately to meet its stated gas production goals of 560 bcm per year in 2010, given the decline in its existing portfolio. Gazprom is likely to have record revenues in 2005 and 2006, and clearly has a wealth of reserves to develop. However, it is unclear to what extent these increased profits are being directed at key upstream and mid-stream activities. Meanwhile in Russia, Gazprom seeks to buy up key independent producers and resists moves to enhance transparency or true third-party access. Gazprom has also been distracted from upstream gas activities by its investments in oil, nuclear, electricity, export pipelines and into Western European gas distribution and retailing. Gazprom intends to become a world-class global, diversified energy conglomerate. Gazprom's recent acquisition of Sibneft for USD 13.6 billion is an example of redirecting substantial investment funds from Russia's upstream gas sector to expand its holdings. While investments to diversify its energy holdings and secure markets downstream may seem a natural investment strategy to many observers, it raises the issue of adequacy and timeliness of traditional gas production and transport investment. Gazprom seems to focus its attention on projects with demanding engineering requirements and the concurrent mega-investment needs. Many analysts expect that Gazprom will require government support, as it has in the past through various tax exemptions, if future mega-projects are to be realised. However, it is not at all clear if this is the best use of government funds.

The role of independent gas producers

There is a growing number of non-Gazprom gas producers and foreign investors who appear ready to provide substantial capital if more competition is allowed in the upstream sector through reliable and more transparent access to the gas transportation network controlled by Gazprom. The Russian Energy Strategy projects non-Gazprom production at between 105-115 bcm in 2010 and between 140-160 bcm in 2020. However, prospects for independent production will depend heavily on an improvement in access terms for Gazprom's gas-processing capacity and transmission system. Large volumes of gas produced by oil companies are still being flared as these volumes cannot find their way to the transmission system economically.[16]

In line with the Russian Energy Strategy, Gazprom's outlook leaves room for independent gas producers to make up for an increasing share of production to meet total demand, reaching 20% of total output by 2020. Non-Gazprom production will need to increase and reach levels of almost 150 bcm in 2020 to meet projected domestic and export demand. This gap is expected to be filled by production from independent producers and/or imports from Central Asia. However, given the dynamics over the past months, it would seem that Russian domestic independents are the more likely source of this production. At Gazprom's Board of Directors' meeting in early February 2006, the role of independents in domestic market supplies and their contribution to Gazprom's export portfolio was discussed. Gazprom's Board is said to have favoured closer co-operation with independents. The extent of practical implementation of this policy should become clear in the next year or two. These moves are supported by government policies to enhance regulation to ensure non-discriminatory third-party access to Russia's natural gas transportation network. A new draft Order and Regulation were submitted by the Antimonopoly Service to relevant Ministries including the provisions for auctions for access to gas pipelines, new terms for gas transportation contracts and better access to information on spare pipeline capacities.

Sector reform

The challenge of creating a more competitive gas sector will have to take as its point of departure the existing structure of the Russian gas industry. To increase gas production from Russian oil companies and independent gas producers, sector reform is essential. This reform will need to reflect the enormous investment challenges ahead, estimated in WEIO 2003 at USD 300 billion over the period 2001-30.

Effective pipeline access and an increase in domestic gas price in Russia are prerequisites for more competition in the Russian gas market and for meeting future domestic and export needs. Although the principle of third-party access to pipelines is established by law, Gazprom has the ability to discriminate against other producers. The company is required to grant access only if there is sufficient capacity available in the system and the company assesses this itself. A lack of transparency (by no means unique to Russia) makes it hard to assess whether Gazprom is justified in refusing access. Gaining the right to sell directly to end-users and to contract with Gazprom for transportation services on a reasonable

16. *Optimising Russian Natural Gas –Reform and Climate Change*, IEA 2006.

basis would allow independent producers to seek better pricing terms and give them stronger guarantees for future revenues.

Russia has agreed to take action to open access to the domestic pipeline network in return for EU support for Russia's accession to the World Trade Organisation. Russia also agreed with the EU to raise its domestic gas tariffs. The European Union has argued that below-cost domestic tariffs represent a hidden trade subsidy. The Russian government promised to raise average prices to industry to between USD 1 and 1.2/MBtu in 2006 and to USD 1.4 and 1.6/MBtu in 2010. This compares with more than USD 8/MBtu for current export prices to Western Europe. Changes here will have to be carefully implemented to mitigate the social implications of higher prices, as well as the industrial impact and the affects on the power sector. Nonetheless, movements towards more realistic prices seem, on the basis of IEA member country experience, likely to yield energy efficiency benefits which could free up gas in Russia for export without compromising domestic energy services (and reducing greenhouse gas emissions, a not inconsequential side effect). Pricing reforms would also stimulate investment in production. Policy moves to reduce the amount of flared gas associated with oil production could boost gas availability by at least 15 bcm, again, with significant greenhouse gas abatement benefits.

Conclusion

In summary there is a serious concern about underinvestment in Russian gas infrastructure. While Russia is not alone in facing such policy problems, their consequences seem much more significant, since Russia is such a an important gas supplier. With its major fields in decline and unwilling to undertake or authorise other domestic options, Russia relies now on Central Asian gas to meet the growth in its contracts with Europe. However, investment in Central Asia appears to be inadequate. Assuming a continuing decline of about 20 bcm per year in its Big-3 producing areas and stagnant imports from Central Asia, current projections suggest a supply shortfall against existing contracts that could reach 50 bcm in 2010 if adequate investments are not made. Timely investments in major new fields and infrastructure supported by market opening and policy changes have the potential to improve the outlook.

China

China represents massive latent demand for gas supplies; the government is increasingly aware that the realisation of this potential will rely on the willingness and ability of consumers to pay market-based prices.

New Chinese policy favours a pipeline import strategy; existing LNG projects benefited from low introductory prices, but further LNG import plans have been scaled back by the government.

Until new supplies come on stream, Chinese gas consumers are expected to suffer substantial interruptions.

Natural gas demand

China's natural gas industry is at an early stage of development, but poised for impressive expansion. The government is committed to a rapid increase in the share of natural gas in the country's energy mix. China (including Hong Kong) produced and consumed 47 bcm in 2004, up from 30 bcm in 2000. Chinese gas demand is growing at a rate of over 14% per year, which may turn China into the third largest gas market worldwide in under two decades, if this trend continues. By 2010, gas consumption is expected to reach about 60 bcm (WEO 2004). Part of this demand is expected to be covered by LNG imports.

According to China's National Development and Reform Commission (NDRC), the next few years may see an even more dramatic upsurge in natural gas consumption than projected in the WEO. The government's target is for gas use to rise to 100 bcm or more by 2010, and to further double to 200 bcm or more by 2020, rising from today's 3% of primary energy use (excluding traditional biomass) to about 10%. Supply-side concerns invariably emerge alongside these strong demand forecasts, and there are already reported shortages. The power sector, which consumes less than 5% of gas currently and which was expected to be the largest new market for gas, has suffered particularly, with 4 GW out of

Figure 39 **China**

11 GW of gas-fired capacity idled in 2005. Recent plans reflect this reality. The 11th Five-Year Plan (2006-10) was approved by the National People's Congress in March 2006. It is the touchstone for government involvement in all aspects of economy and society. The plan calls for an "appropriate degree" of development of gas-fired power generation. This contrasts with previous, more enthusiastic statements of support. This development will depend greatly on how another item of the 11th Five-Year Plan is treated, i.e., reform of the mechanism for setting natural gas prices.

Because of its limited domestic reserves, China is looking for significant imports, in the form of pipeline gas from Russia and Central Asia, as well as LNG. The increase in demand for LNG in particular is driven by the population and economic growth in China's coastal cities and provinces, and the increasing desire to improve air quality by switching away from coal.

Role of LNG

China has a number of LNG import terminals planned, with the main project developers being the China National Offshore Oil Corporation (CNOOC), China National Petroleum Corporation (CNPC, with its stock exchange traded subsidiary PetroChina), and the Chinese Petroleum and Chemical Corporation (Sinopec).

As a complement to increasing domestic natural gas production from their off- and onshore fields, the three companies had proposed about 20 different LNG terminals along the east coast to handle imports from across Asia, the Middle East and elsewhere. However, the Chinese government recently intervened to restrict the future development of its LNG industry, assigning different operational areas to its NOCs and forcing most of their planned projects to be dropped.

Table 4 **LNG re-gasification terminals in China**

Main developer	Location	Capacity	Status	Planned Start
CNOOC	Shenzhen, Guangdong	3.7 mtpa	under construction	2006
	Putian, Fujian	2.6 mtpa	under construction	2009
	Ningbo, Zhejiang	3 mtpa	feasibility study	2010
	Yangshan, Shanghai	3 mtpa	feasibility study	2011
CNPC	Tangshan, Hebei	3 mtpa	feasibility study	after 2010
	Dalian, Liaoning	4 mtpa	feasibility study	after 2010
	Rudong, Jiangsu	3.5 mtpa	feasibility study	after 2010
Sinopec	Qingdao, Shandong	3.3 mtpa	feasibility study	after 2010
	Tianjin	unknown	pre-feasibility study	unknown

Source: based on information in news service reports and in Akira Miyamoto and Chikako Ishiguro, January 2006, Pricing and Demand for LNG in China, Paper NG 9, Oxford: Oxford Institute of Energy Studies. This table excludes projects that have been announced by project developers but have not proceeded to at least the pre-feasibility study stage

After the new directives from the NDRC, the following projects, (Table 4) totalling over 26 mtpa of capacity, remain on course for development, but only one new project looks feasible before 2010. Intentions to construct further phases of most of these terminals have also been announced. Plans for at least seven other terminals may be revisited at a later date.

Two projects are under construction. The 5 bcm per year (3.7 mtpa) terminal constructed by a CNOOC-led consortium in Shenzhen, Guangdong Province, should receive first LNG shipments from Australia's North West Shelf Venture in mid-2006 and become operational in the summer. A second terminal in Putian, Fujian Province (also a CNOOC project), with 3.5 bcm per year (2.6 mtpa) capacity, may start receiving LNG from Tangguh in Indonesia in 2009. CNOOC is also leading the development of a terminal in Ningbo, Zhejiang, with design capacity of 4 bcm per year (3.0 mtpa), that is now in feasibility-study stage. LNG for Zhejiing was to have come from Australia's Gorgon project, under an initial agreement signed in 2003, but CNOOC recently withdrew from negotiations reportedly due to differences over pricing, and the LNG was contracted to Japanese utilities. Thus, supplies for the terminals now in various stages of planning have not yet been identified.

New import pipelines

The current backbone of the Chinese gas transmission grid is the West-East pipeline, a 4 200 km long pipeline, built to transport gas from western reserves to eastern markets (see Investment in the Gas Sector Section). PetroChina recently announced a plan to invest USD 12 billion in pipeline expansion, including 8 000 km of gas transmission lines, to be completed by 2010. The 11th Five-Year Plan calls for the construction of this pipeline, as well as imports of pipeline gas, "at the appropriate time."

Currently proposed projects to import gas by pipeline include plans that would bring gas to China:

- From Russia's Kovykta gas field near Irkutsk to northeast China and Beijing and then to South Korea.
- From Chayandinskoye gas field in northeast Siberia.
- From Sakhalin.
- From Turkmenistan and/or from Kazakhstan/Azerbaijan.

Despite the signing of numerous agreements, including one between CNPC and Gazprom on the occasion of President Putin's visit to Beijing in March 2006, the exact sources of gas and pipeline routes, not to mention quantities and prices, are still matters of some debate. The CNPC/Gazprom agreement calls for 60 to 80 bcm per year to be delivered to China, starting with gas from West Siberia that would flow into the second West-East pipeline in 2011, and later including gas from Sakhalin and possibly Kovykta that would be delivered through an eastern pipeline, at a price to be set with reference to oil prices in Asian markets. Much work remains to be done before these plans will bear fruit. Similarly, recent agreements with Turkmenistan and with Kazakhstan to supply up to 30 bcm per year from each country represent only incremental steps in a long and uncertain process, not least because the resources identified as going to China may also be expected to transit and/or serve other markets.

Over the next three decades, China is looking to build an interconnected network linking LNG terminals, West-East pipelines, and import pipelines. Considerable work also remains to be done in articulating distribution networks to connect end-users.

Possible barriers for development of the gas market

The expected persistence of higher prices appears likely to slow down development of LNG and possibly pipelines. Power generators, which were expected to be major customers for gas, are loathe to accept prices higher than about USD 4/MBtu, since coal is a relatively cheap alternative with a secure long-term supply outlook. The government's pricing authority, NDRC's Price Bureau, has been hard pressed to come up with a way to stimulate demand for gas by keeping prices low enough for consumers to accept, while making it financially feasible for suppliers to bring in imports. NDRC has announced that gas prices will rise annually over the next several years, by up to a total of 40%, but it is an open question whether that will be sufficient to expand markets to meet the government's targets.

India

Gas demand in India is outpacing supply at current price levels; priority is given to public power- and fertiliser producers and even these are operating at low capacity factors.

Strategic gas import projects involving pipeline connections with Iran, Turkmenistan and Myanmar are still under discussion but show little progress.

There is evidence that certain Indian industries are prepared to pay higher prices but the gas pricing system needs to be reformed to encourage further domestic gas exploration and gas imports.

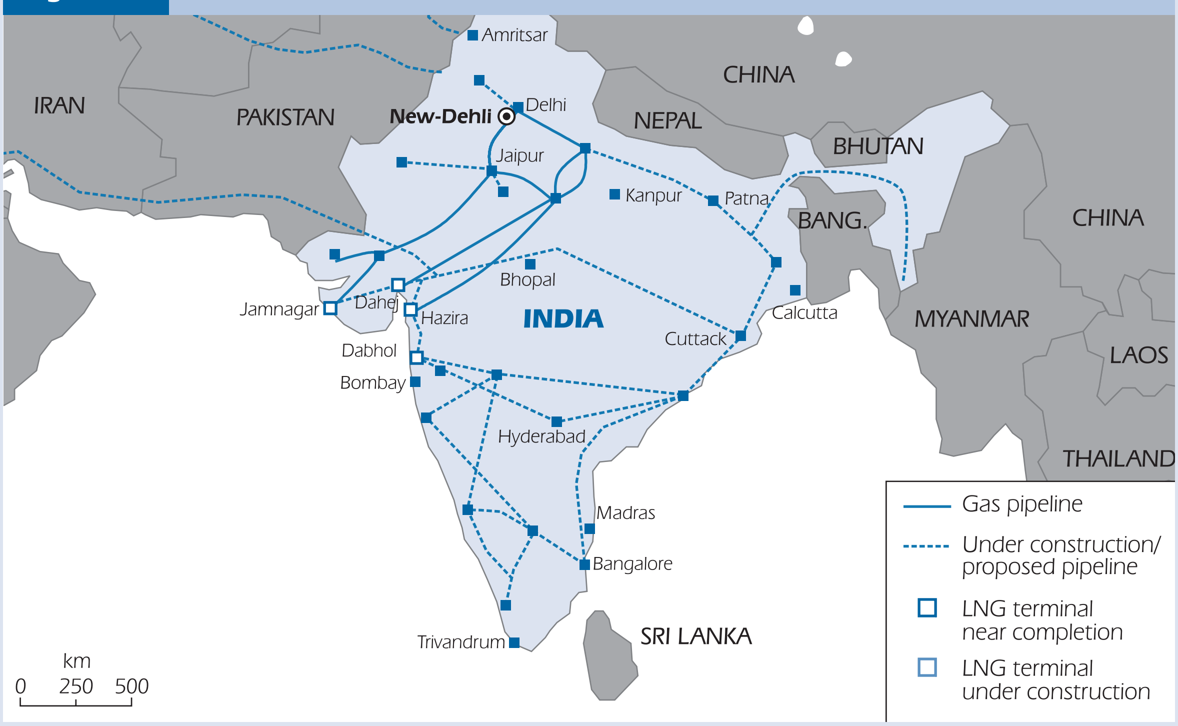
Supply and demand

India's gas consumption during the fiscal year 2004-05 was 34 bcm. Of this 19% was supplied in the form of LNG imports. The government estimated that total potential demand for gas in the same year was 87 bcm; indicating a substantial supply gap. The government estimates that domestic production will increase from 27 bcm in 2004-05 to about 44 bcm in 2010. The projected increased domestic supply reflects major gas finds made under the New Exploration Licensing Policy (NELP). Domestic reserves have increased from 717 bcm in 2001 to 1 072 in early 2005. Most of the finds were made in fields allocated under NELP I – IV; NELP VI was launched in early 2006.

Overall gas availability in India in 2010 is expected to increase to over 57 bcm. The government projects potential demand to reach over 100 bcm in the same year. These supply and demand projections include LNG supplies of about 19 bcm but exclude piped gas. India currently imports LNG through two operating terminals both located at the Western coast. The Dahej facility has a capacity of 6.8 bcm per year (5 mtpa) and the Hazira facility a capacity of 3.4 bcm per year (2.5 mtpa). While the Dahej capacity will be doubled by 2008, the Hazira terminal currently remains underutilised. This reflects the fact that the operators of the Hazira terminal were not able to secure either long-term supplies, or long-term buyers. The terminal operators have been bringing in spot deliveries at prices substantially higher than those negotiated for the Dahej facility and have faced problems to find solvent buyers. In addition, the Dabhol facility, part of the former Enron complex, has a capacity of 3.4 bcm per year (2.5 mtpa) and was expected to be put into operation in mid-2006. However, the operators have so far been unable to secure supplies at a price acceptable to its major off-taker, the Maharashtra State Electricity Board. Thus, the start of operations has been postponed to 2007. At the same time, the operators of the Dahej facility are moving ahead to constructing a second LNG facility at Cochin in the state of Kerala, with a capacity of 3.4 bcm per year (2.5 mtpa). The Kerala State Electricity Board and the industrial complex are expected to be the main off-takers.

The three potential gas pipeline sources (Turkmenistan, Iran and Myanmar) that were extensively discussed during 2005, have been pushed back in early 2006. Consequently, the expected gas supplies of over 36.5 bcm are not included in official supply projections up to 2010.

Figure 40 **India**



India faces major challenges to develop a gas economy, owing to the lack of sufficient transmission infrastructure, the lack of coherent legal and regulatory sector frameworks, questions about the affordability of gas and the size of the demand/supply gap. However, the major issue is the affordability of gas, in particular for the power sector.

Pricing

Due to insufficient public sector gas, gas-fired power stations could only operate at a plant-load factor of 56% during 2004-05. The Ministry of Power calculated that this resulted in a significant generation loss. The price for public gas was set at USD 2.95/MBtu including transportation and taxes, independent of location, in October 1999. It was only in May 2005 that the government agreed to a 12% increase in gas prices for the power and fertiliser sectors. All other sectors, except compressed natural gas (CNG), and very small consumers will now have to pay the same price for public sector gas as for Joint Venture gas which was USD 3.86/MBtu at that time. The Joint Venture operators are now requesting USD 4.75/MBtu; however, as of April 2006, they have not received government approval for this price.

Pricing of private domestic gas is of crucial importance for the future role of gas in India's fuel mix, as the share of public subsidised gas is expected to fall sharply in the future. It is expected to account for only one-third of total supplies in 2012. This implies that the power and fertiliser sectors, which are seen as the major future gas consumers, will need to be in a position to absorb market prices by then. The Ministry of Power has calculated that gas demand will fall from 62 bcm per year at a gas price of USD 3/MBtu to 36 bcm per year for a gas price of USD 4/MBtu. The high price elasticity of demand was underlined when public power producers declined to pay the market prices demanded from private gas producers and opted instead to operate plants at lower capacity.

However, the fact that the Dahej LNG terminal operator, Petronet LNG, is not only expanding this terminal but also constructing a second facility, shows that there is sufficient demand for gas at market prices in India. Based on a study undertaken for Petronet LNG, demand in the industrial sector is particularly high. In the existing supply shortage situation, gas provision to the industrial sectorswas constrained to allow priority servicing of public power and fertiliser producers. The industrial sector consequently had to rely on alternative fuels, primarily naphtha, which is generally more expensive than LNG.

While India's overall gas supply picture is improving, the absence of a sufficient transmission network remains a major obstacle to supply gas to solvent clients. The country still relies on the 1 800 km Hazira-Bijaipur-Jagdishpur trunk pipeline connecting the north-western coast with the northern market. There is currently no pipeline infrastructure in place to bring the new domestic gas from the south-eastern coast to the demand centers. The government recently estimated a total investment requirement for gas pipeline infrastructure in the order of USD 5 billion.

It is hoped that the Petroleum and Natural Gas Regulatory Board Bill which was finally approved by parliament during its last session, will facilitate raising funding for the required gas infrastructure. The major features of the Bill include regulation of transportation of gas by pipeline, permission of common-carrier non-discriminatory access in petroleum product and gas pipelines and notification of existing pipelines as common carrier among others.

Indonesia

Indonesia has long been the world's largest LNG exporter, accounting for 17% of world LNG capacity in 2005, and is central to Japanese and Korean LNG supply.

The Indonesian government is re-defining the role of natural gas in Indonesia's economy in favour of domestic supply. A resulting lack of investment in Indonesian gas production means that Indonesia cannot now fulfil its supply contracts despite its wealth of reserves.

Introduction

Located in the economically dynamic East Asia region, Indonesia is the world's fourth largest country: it has a population close to 250 million, of which some 30% are below the poverty line. Indonesia is resource-rich: in 2005 it was the largest global exporter of LNG and Southeast Asia's largest producer of oil, gas and coal. Its energy and mineral exports account for a quarter of the country's export revenues.

Figure 41 Indonesia

As an emerging economy, Indonesia's low labour costs and domestic/regional market potential has brought annual GDP growth averaging 5%+ in recent years. Indonesia has increasing energy demand but, although gas-rich, it has retained a high dependence on oil. Indonesia is seeking to reduce this dependence but a number of barriers are impeding progress.

A slowdown in oil and gas sector investment

Indonesia has considerable oil and natural gas reserves, and is an OPEC member country. In recent years, production from existing fields has been declining and the development of new fields has been limited. Coupled with its growing domestic demand for petroleum, Indonesia became a net oil importer in 2004.

Indonesia is in dire need of stimulating exploration and development if it is to reduce oil imports and maintain its lucrative LNG exports. The most recent Oil and Gas Law, passed in October 2001, was intended to liberalise its upstream and downstream oil and gas sectors and make them more transparent and attractive to foreign and local investors. The law will transform the national oil and gas company, Pertamina, from a state enterprise to a competitive limited liability company. Pertamina's role of granting oil and gas licenses and managing production sharing contracts has been transferred to BP MIGAS, a new implementing body within the Ministry of Energy and Mineral Resources.

However, political concerns and entrenched local interests have delayed the complete implementation of the Law. Coupled with Indonesia's unsettled political and governance climate, the result has been a slowdown in oil and gas field development and a reluctance on the part of investors to participate in further oil and gas exploration and development.

In 2004, Indonesia elected a new President, Susilo Yudhoyono. President Susilo won power on promises of tackling graft and governance issues and improving guarantees to encourage investors to come to Indonesia, such as legal certainties, political stability, law and order, sound tax policies, customs policies, good labour management. Since then, President Susilo and his minister of energy and mineral resources, Purnomo Yusgiantoro, have been more rapidly implementing the Oil and Gas Law.

Over 2005, President Susilo and Minister Purnomo made hard decisions on major long-standing issues impacting Indonesia's oil and gas sector and its governance, including winding back petroleum subsidies/price caps and pursuing industry liberalisation. Indonesia's petroleum price caps and subsidies priced retail diesel, kerosene and gasoline at a level that was amongst Asia's lowest and about 30% of the international parity price in 2005. As a result of the rising global crude and product prices, the subsidies 'sheltering' the Indonesian consumer were expected to cost the Indonesian government about 1/3 of total forecast government expenditure for 2005. Apart from encouraging smuggling and corruption, the retail price capping also provided little incentive for Indonesians to exercise price-driven demand restraint or to explore alternative fuel options such as natural gas.

Natural gas in the Indonesian energy economy

Indonesia has estimated natural gas reserves of 5 tcm (176 tcf) of which roughly half are proven. Most of the reserves are located in the following areas:

- Arun field in Aceh.
- Badak field in East Kalimantan.
- Offshore Java.
- Irian Jaya.
- Natuna D-Alpha field, the largest in Southeast Asia.

Indonesian gas production is dominated by the foreign oil majors Total, Chevron and ExxonMobil. Pertamina's presence in the upstream gas sector is relatively small. While oil production has flagged, companies have had more success finding and producing gas, and Indonesia produces about 80 bcm per year of gas each year. However, while gas production is high, Indonesia's domestic gas consumption is only half of this. The other half is exported as LNG and piped gas. Looking at Indonesia's commercial energy mix, Indonesia continues to rely on oil to meet 50% of its energy requirements, with coal and geothermal providing another 20%. Natural gas provides only 30% of Indonesia's energy requirements, and over 40% of this amount is consumed in the oil and gas sector (including natural gas liquefaction).

Indonesian gas exports

About 90% of Indonesian gas exports are LNG and 10% is cross-border piped gas. There is a strengthening Southeast Asian regional interest in pipeline trading of natural gas, based largely on the commercial interconnection of national gas systems. Known as the Trans ASEAN Gas Pipeline (ASEAN – Association of Southeast Asian Nations), the TAGP is becoming real as more cross-border interconnections are commissioned. For Indonesia, two interconnections have been commissioned: a pipeline connecting West Natuna to Singapore (640 km, 9 mcm/d) and one from Sumatra to Singapore (500 km, 10 mcm/d). Further cross-border interconnections and internal transmission links are planned.

Indonesia's LNG liquefaction capacity is 17% of the global total, exceeding 40bcm per year, with further installations planned. Indonesia's LNG is supplied on long-term contracts totalling approximately 35 bcm per year, with about 70% going to Japan, 20% to Korea, and the remainder – to Taiwan. The current liquefaction plants in operation are Arun and Bontang (the largest plant in the world) and both are operating below capacity. Some Arun contracts are due for completion in 2007 while Bontang contracts are due over 2011 to 2018. A new LNG plant is under construction at Tangguh, owned by BP, CNOOC and a Japanese JV. It will have a capacity of 10.3 bcm per year (7.6 mtpa), with the first train to be commissioned in 2007 and the second in 2009. The project is earmarked for the Chinese, Korean and United States' West coast markets.

In 2004, Indonesia's declining gas production coupled with its domestic demand for gas as a feedstock (especially for the fertiliser industry) and as a petroleum substitute (especially for the power and industry sectors), prompted the Indonesian government to readdress

Indonesia's LNG export trade. In late 2004, PT Arun complied with a request from the Indonesian government to make some of its LNG-destined gas available to local customers, particularly the local state-owned fertiliser produces. In early 2005, Pertamina negotiated the rescheduling of some 51 cargoes (each cargo typically holding 60 000 tonnes of LNG) that had been stipulated under long-term contracts with Japan, Korea and Taiwan for 2005. It was not clear whether the re-scheduled cargoes were to be delivered at some later date. In late 2005, BP MIGAS and Pertamina advised that 48 cargoes would be cut from Indonesia's 2006 shipments to Japan, Korea and Taiwan, this has since increased to about 65 cargoes. A further blow to the LNG industry was announced in January. The operator of the Bontang LNG facility announced that 4 of their 8 LNG trains could close as early as 2008 as a result of supply shortages. A planned 1 200 km undersea pipeline that will link east Kalimantan fields with the markets of Java will take much of the current LNG-destined production.

As of early 2006, the Indonesian government is now assessing how much natural gas it must allocate for domestic consumption and how much for LNG export. In January 2006, Minister Purnomo announced that his Ministry was to submit to Parliament an amendment to the petroleum Law that would require companies with Production-Sharing Agreements (PSA) with Pertamina to sell at least 25% of their oil and gas production to local buyers. This will limit the oil and gas available for export to 75% of that produced. This may result in a saving to the local buyers that is commensurate with the deferred transport costs of otherwise importing the oil, and it appears that the oil and gas are to be sold at some capped local price. This draft legislation will do little to encourage investors into the oil and gas sector.

Understandably, Indonesia's inability to fulfil its long-term contracts has troubled its North Asian customers. With spot LNG cargoes difficult to secure and commanding a higher price than its long-term LNG contracts, Indonesia is facing a difficult and expensive shortfall.

Indonesia's limited gas pipeline network prevents the rapid expansion of gas demand. The current transmission and distribution system consists of nine unconnected networks, centred on Indonesia's gas fields and their vicinity. Given that most of these fields are not on Java, this presents a problem. PGN, the State-owned gas transmission and distribution company, estimates that there is a potential market of some 25 million households, principally in and around the larger cities of Java. In addition, there is a large industrial market currently consuming petroleum. However, a change in gas prices requires government approval, and PGN has said that to establish urban gas distribution will require higher retail prices. Consequently, it will focus on large-scale sales to industrial consumers. PGN is planning four major new gas pipelines to improve the connectivity of Indonesia's existing network. Two projects are underway. The 450 km central Sumatra to north Sumatra (Duri-Dumai-Medan) pipeline will be complete in 2007. The 500 km south Sumatra to west Java pipeline will be complete in 2006 and will link the gas-rich south Sumatra with Indonesia's main industrial regions of Banten and west Java.

With 30% of its power stations still burning fuel oil and diesel, PLN, the state-owned electricity generation, transmission and distribution company, has proposed an LNG terminal and re-gasification facility in west Java. The facility will supply gas to its power stations as part of its programme to reduce dependence on petroleum. Future PLN and IPP power stations will be either coal or gas-fired.

Conclusion

The place of natural gas in Indonesia's energy economy is going through a major transition. Prompted by high oil prices and declining indigenous oil and gas production, the Indonesian government has begun the process of moving the role of gas from export revenue earner to that of being a more significant component of the domestic energy mix in place of petroleum. Simultaneously, the government recognises that the lack of major new investment in the oil and gas sector means that it has not yet implemented appropriate changes to the oil and gas investment climate.

Algeria

Algeria holds the eighth largest proven reserves of natural gas in the world, at 4.6 tcm, mostly as associated gas.

Algeria is the world's fifth largest natural gas producer (the largest in OPEC) and the fourth largest global gas exporter. Sales are expected to rise from 65 bcm in 2004 to 76 bcm by 2010.

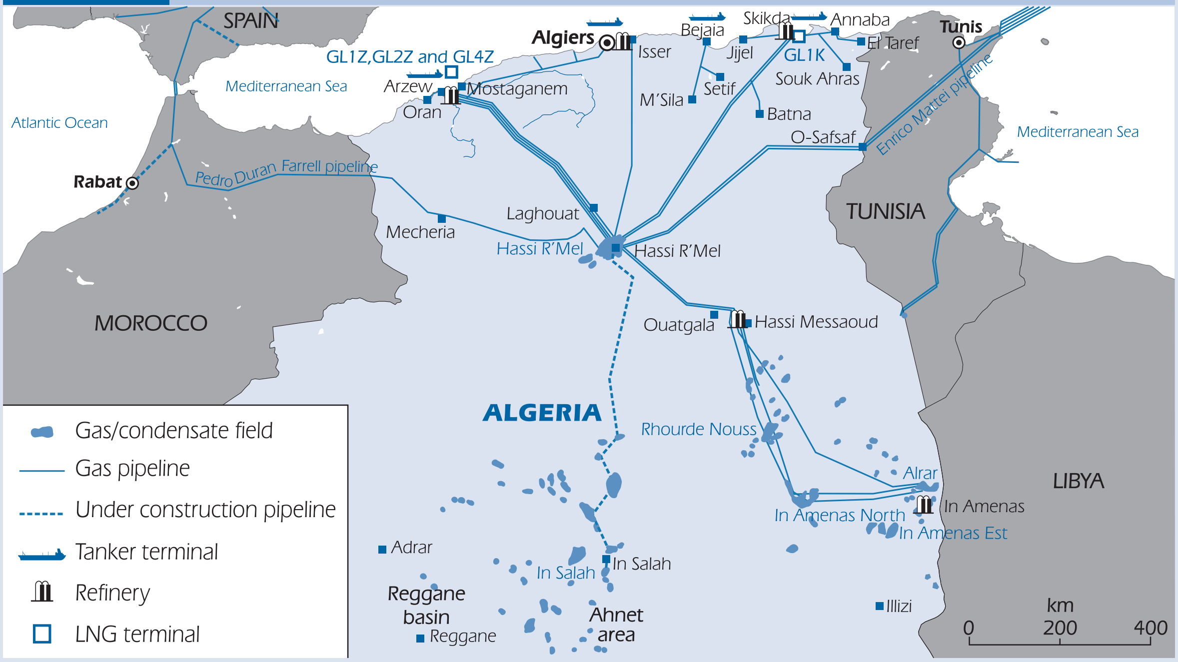
Sonatrach, the national petroleum company, is the dominant player in the country, but it is working in co-operation with foreign companies in gas production. Major policy changes in 2005 pave the way for restructuring of Sonatrach, and further opening up of competition from domestic and foreign companies.

Reserves and production

Algerian gas reserves of 4.6 tcm (160 tcf) are substantial, underpinning the local supply and a thriving export industry. More than half of these reserves are concentrated around Hassi R'mel, operated by Sonatrach, which accounts for more than three-quarters of marketed production. Further south around In Salah, production started in 2004 from a Joint Sonatrach/BP/Statoil venture, the first gas project in Algeria involving foreign cooperation. The USD 2.5 billion project is now producing 9 bcm per year and further Joint Venture projects will expand gas output to 107 bcm in 2010, from 88 bcm in 2003.

Exports are based on both pipeline and LNG trade. Pipelines run through Tunisia and under the Mediterranean Sea, supplying Italy (27 bcm per year), and to Spain via Morocco (12 bcm per year). Both pipelines are being expanded and a third pipeline joining Algeria and Spain directly (Medgaz) is due to start construction soon, with deliveries of 8 bcm per year from 2009, at an estimated capital cost of around USD 750 million. An additional pipeline linking Italy and Algeria via Sardinia is under feasibility study. This pipeline, the GALSI project, is being advanced by a consortium of Sonatrach and European

Figure 42 **Algeria**



companies. Algeria was a very early entrant to the LNG market. In 2003, 40 % of exports comprised LNG, with France and Spain the main buyers. Europe is expected to be the main focus of expanding LNG shipments due to its proximity, but the North American market is also served. Overall exports will rise to 76 bcm in 2010, from 64 bcm in 2003.

Foreign involvement

Sonatrach was formed in 1963. It retains a dominant position in the hydrocarbon sector, although it has a long history of technical co-operation with other countries and companies. In addition the sector is gradually being opened up to foreign investment, first in oil, and more recently, in gas. The new hydrocarbon law of 2005 is expected to accelerate this trend. For example, foreign companies will be permitted to build and operate their own gas export pipelines, hitherto held exclusively by Sonatrach. Coupled with the country's already relatively attractive investment climate, this means that the significant capital needs of the oil, gas and electricity sectors should be met relatively easily.

STORAGE

Although the amount of gas stored in a country may represent 30 days of firm demand, this does not mean that it can rely solely on gas storage to supply its needs for a month. Strategic gas storage is a potential option to protect downstream markets, but is expensive and not as flexible or effective as oil stocks.

Power markets are increasingly using gas-fired generation to provide power flexibility in the absence of efficient methods of storing power. In turn, this makes gas markets more volatile, resulting in increased demand for high- deliverability storage.

The LNG spot market can be used as a source of supply flexibility, whereby consumers buy spot LNG in the winter, and sell in the summer. However, LNG consumers are located in the northern hemisphere and, therefore, experience peak gas demand at the same time.

The functions of gas storage

With high upfront capital costs and relatively low marginal costs, gas producters are encouraged to use the production infrastructure, such as wells, liquefaction plants and pipelines, at very high load factors, meaning they aim for a more or less constant rate of gas supply to maximise use of their assets. Gas consumers, however, use gas with varying patterns and according to their own economics, and consumption profiles vary throughout the day, the week and the season of the year. An example is given in Figure 43.

Industrial gas users often vary their output only marginally on a day-to-day basis, and commit to buy large quantities of gas on flat profiles throughout the year. The residential market requires gas for home heating on a seasonal basis, varying with weather conditions, with peaks in the winter and troughs in the summer. For example, the United States' residential winter peak-demand is seven times higher than the residential summer-demand. Power utilities demand gas for balancing the system on a very unpredictable basis in certain countries, such as the United States, where gas is mostly used for peak generation at certain times of the day. However, the power industry uses gas on a more regular profile in Japan, where gas-fired power forms the intermediate/base load in the merit order.

Certain countries have access to domestic supplies of gas which can be varied according to the demand pattern, called swing supply. The Groningen field in the Netherlands is a swing field which can match its output to demand on a daily basis. The United Kingdom was in this position several years ago with its offshore swing fields, which explains why it has relatively few storage sites. In most cases however, some form of gas storage is used in order to match the uneven, volatile demand to the more smooth profile of supply. Having said this, the amount of gas storage required in any given market is a function of many parameters.

Figure 44 shows the seasonal pattern of storage in the United States both over the five-year range and the current year (the blue line). Storages are depleted in winter and filled in summer. It is possible to see

Figure 43 **Consumption and supply patterns differ. Illustrative example – northern hemisphere**

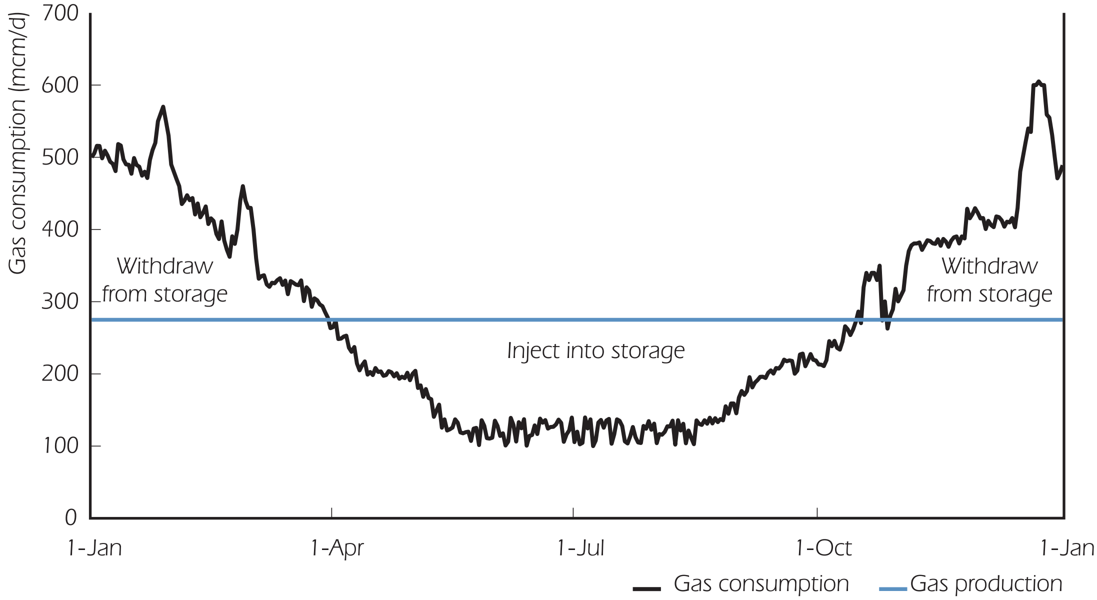
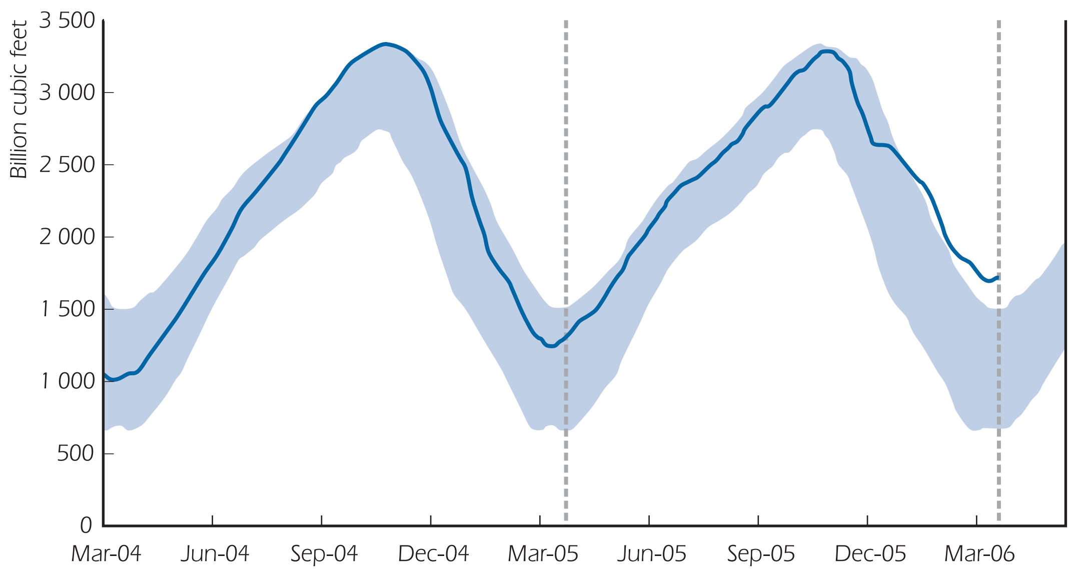


Figure 44 **Working gas in underground storage compared with 5-year range, United States**



Source: EIA

the effect of the mild winter on storage from December 2005 through to March 2006 where the gas in store rises above the five-year average.

IEA countries in general have mature domestic and commercial gas markets; while they might, therefore, have sufficient seasonal gas storage, gas-to-power growth puts new demands on their short-term storage. As power generation is becoming a more important use of gas, gas storage requirements need to modify accordingly.

Demand management

A corresponding method for managing volatility in the gas market is through using demand-side techniques. Japanese and Korean gas companies are well versed in this for several reasons: they have almost no domestic production, limited storage, and limited flexibility in their LNG import contracts. In Japan, companies have been careful to build up gas demand from industrial users with regular demand profiles, as well as residential and commercial customers with more seasonal demand. In Korea, 45% of gas use goes to the seasonal (residential and commercial) markets which have peak demand nearly ten times higher than the lowest demand.

The power sector is central to demand management, because more gas-fired generation can be used as base load in the summer than in the winter to even the overall demand pattern. The power sector must be able to maintain spare generating capacity all year round in order to switch from gas to other forms of generation although this represents a cost to the power industry. The demand curve can be smoothed throughout the year by building demand for gas in the off season. Several countries including the United States, Spain, Japan and Korea, are starting to see a sizeable summer gas demand peak caused by air conditioning demand met through gas-fired power generation.

Allowing gas prices to reflect supply and demand fundamentals will also modify demand behaviour – prices generally will be higher in winter and lower in summer. How this generates a market response depends on the elasticity of demand in each sector – perhaps less gas will be used for home heating, perhaps power generation will provide the balancing demand or perhaps companies will be able to build cost-effective gas storage.

Fuel switching is another very important source of demand-side flexibility. IEA data collected in 2006 suggests that gas consumption by the European power sector can be reduced by approximately 10% by switching to another fuel, although this is not used in normal operation of the gas market because there is no price signal to do so.

The spot LNG market can be used as a source of supply flexibility, whereby consumers buy spot LNG in the winter, and sell in the summer. However, LNG consumers are located in the northern hemisphere and, therefore, experience peak gas demand at the same time. We can, therefore, expect global spot LNG prices in the winter to be considerably higher than in the summer, an effect already emerging in winter 2005-06.

Aspects of storage

There are several physical parameters which can be used to characterise a gas storage site: working volume, injection rate, withdrawal rate and cushion gas volume. Simplistically, the working volume can be regarded as the useful amount of gas in the storage. The injection rate of a gas storage site is the amount of gas which can be put into storage in a given time period. Facilities with very low injection rates have to be filled over periods of several months, while those with fast injection rates typically fill up over shorter periods, perhaps a few days or weeks. The injection rate of a storage facility is related to its physical characteristics. In general, geological storage can receive gas at maximum injection rates from 10% full until approximately 80-90% full at which point the rate of injection starts to appreciably drop. One full injection period followed by a withdrawal period is referred to as a storage cycle.

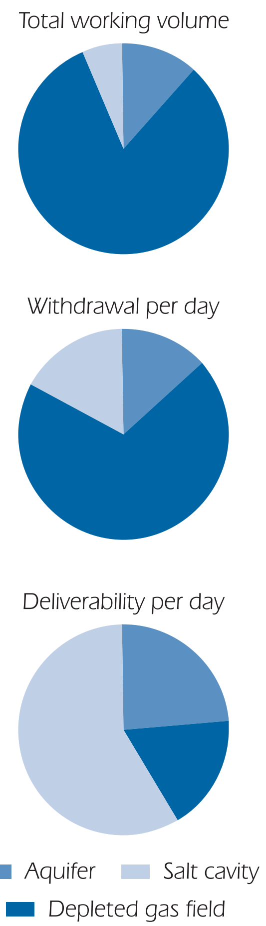
The withdrawal rate, also called deliverability, is the amount of gas that can be withdrawn in a certain amount of time. The withdrawal rate can depend on the amount of gas present in the storage. Often gas storages have either a high deliverability rate, but a low working volume, so that they can quickly react to sudden changes in demand, or they have a more modest withdrawal rate but a high working volume, which can sustain send-out for a longer time period. The withdrawal rate of a facility is restricted by its design parameters and limited by physical characteristics. The working volume may be such that it represents a week of total supply for a country, the withdrawal rate may limit this volume to be extracted in longer than 2 months. For example, the Rough storage facility in the United Kingdom has a working volume equivalent to 5 days demand, but the fastest that this gas can be released is 67 days. To say that a country, therefore, has gas in storage equivalent to 30 days demand does not mean that it can rely solely on gas storage to supply its needs for a month.

Cushion gas is gas present in the storage site, which is necessary for the functioning of the facility – it, therefore, does not form part of the working gas. Cushion gas either maintains the physical characteristics of the storage space by maintaining pressure, or prevents chemical or mechanical change to the storage (e.g., cavern collapse). The volume of cushion gas required to operate a storage site, therefore, depends on the type of storage. The figure can vary between 30% and 80%. Financially cushion gas can be regarded as working capital that can be recovered at the end of the project life of the storage facility. Nevertheless, some storage requires such large amounts of cushion gas that they have a major bearing on investment decisions, especially when gas prices are high.

Types of storage

There are three major types of storage: depleted fields, aquifers and salt caverns. Additionally, LNG tanks can be regarded as storage. Large numbers of these types of storage are found in OECD countries, but their physical characteristics differ substantially. As can be seen from Figure 45, the largest proportion of total working volume is held in depleted fields, followed by aquifers and then salt cavities. In the same order, these facilities have successively higher maximum withdrawal rates per day, which means that a salt cavern storage is capable of delivering a much higher proportion of its working volume in any given day (% deliverability per day).

Figure 45 Storage use in the OECD countries



Source: IEA data

Depleted fields: long/medium-term storage

Depleted fields are former oil or gas- producing reservoirs that have been exhausted of recoverable natural gas. When a gas field has been fully produced, an underground formation is left behind which is (in most cases)[17] geologically capable of holding natural gas. In order for the depleted field to be suitable for conversion to gas storage, the field permeability and porosity must be taken into account.[18] The full process of converting an onshore gas production field to a suitable storage site can take as little as 2 years, though offshore sites will take longer.

Unfortunately, depleted fields are often situated in production basins which can be prohibitively far from the source of gas demand. While depleted fields usually have high working volumes, this gas can only be withdrawn slowly – the average withdrawal rate from the existing OECD countries' depleted field storage is less than 2% of working volume per day (min: 0.4%, max: 7.2%). This makes them ideal for smoothing demand between summer and winter. In most cases, they need several days to change from injection to withdrawal mode which makes them less suited to managing short-term volatility.

Aquifers: long/medium-term storage

Aquifers are naturally-occurring rock formations that are saturated with water. Aquifer development is very

17. Except if the properties of the formation have been modified by the production of the gas, e.g., movement of water or oil.

18. Rather than being found in an empty cavern underground, gas is usually found in permeable rocks and/or sands which, therefore, have measurable porosity and permeability.

expensive, because it involves seismic testing analogous to that performed in exploration for gas reserves. Particularly powerful compressors are required to pump gas into the existing water table, and the gas extracted from the storage then contains moisture, meaning that treatment is needed before the gas can be re-injected into the grid system. Because the formation is not a perfect seal, a certain amount of gas injected is never recovered and there is a possibility of water table contamination. In addition, the requirement for cushion gas is especially onerous; up to three in every four cubic meters of gas might be needed just to provide the pressure for the remaining 1 cubic meter to act as working gas. In times of high gas prices, this is likely to prevent the development of many aquifer storage sites, particularly as the chances of recovering all the cushion gas are very low even after the site is shut down.

Because of the time, expense and environmental issues, aquifer storage facilities are normally developed only in demand centres where there are no depleted fields, as they perform a similar role, given their relatively low injection and withdrawal rates. The average withdrawal rate from existing OECD countries' aquifer storage is less than 2.7% of working volume per day (min: 1.4%, max: 4.3%). Aquifers need less time than depleted fields to change from injection to withdrawal mode which makes them more capable of managing short-term volatility.

Salt caverns: short-term storage

Salt caverns are either natural or man-made underground formations which can be used to store gas; they come in two forms, salt beds and salt domes. While salt beds are relatively shallow and uncompacted, domes are usually made of much denser material. In a dome formation, salt forms a very strong vessel and when high pressure gas is present, this plasticises the salt to make a very effective seal. The dome is ideally suited to prevent gas from escaping, and resists degradation over the lifetime of the facility. A salt cavern can be made by leaching from a solid salt deposit. This is done by repeatedly cycling water into the structure through a well to dissolve a cavern.

There are no porosity/permeability issues with a salt dome structure. Injection and withdrawal do not involve gas travelling through sands or porous rocks, instead the gas is injected straight into a "hole in the ground". Because of this, the cushion gas requirements for a salt dome are less than one-third of the total volume, providing for good working-capital economics. In addition, the withdrawal and injection rates are very high, with a full cycle taking as little as a week, so very little notice required. However, much lower volumes of gas can be stored, meaning that salt cavern storage is normally used for balancing inter- and intra-day volatility of demand, but would not be able to smooth seasonal demand swing.

The average withdrawal rate from existing OECD countries' salt cavern storage is 6.5% of working volume per day but there is an unusually high range between the minimum and maximum (min: 1.3%, max: 32.0%). Salt caverns are geologically able to support the change from withdrawal to injection and back in a day, which makes them more capable of managing short-term volatility. While most salt cavern storage is operated on monthly cycles, if there is enough demand then they can be fitted with equipment to further decrease the cycle time.

While salt dome storage sites are expensive to build, the lower cycle time means that they can earn their investment costs back faster. However, operation of a short-term storage site is much more risky than of a seasonal storage site – a short-term storage site needs daily monitoring, whereas a seasonal storage site can (almost) be planned to inject gas in the summer and withdraw in the winter.[19]

LNG

LNG re-gasification terminals receive cargoes of gas in liquid form directly from the ship and immediately transfer it to LNG storage tanks. These tanks can store gas for several days, and are used as a buffer before re-gasification and send-out onto the grid until the next ship docks and unloads the next cargo. LNG tanks allow auto-refrigeration of the liquid, allowing gas to boil off, which cools the liquid. This gas is then re-liquefied and re-introduced into the tank until needed for the send-out of gas. The process of liquefying natural gas takes a substantial amount of energy, so LNG is not usually stored in large quantities for a long time. The added value of storing natural gas in tanks is that none will leach away, and that the withdrawal rate is very high. The average withdrawal rate from existing OECD countries' LNG storage sites is 9% of working volume per day at base load, or 13% at peak. It is possible to use LNG terminals only in winter and leave them idle in summer. This could be considered as supply swing and does not maximise asset use, but could well be a sensible business strategy for LNG suppliers who have clients for summer gas and for winter gas.

Peak shaving and line-pack: short-term storage

During periods of extremely high or low demand, peak-shaving facilities can inject high amounts of gas into the system for a very short period of time. These facilities consist of a small LNG storage, sometimes with its own small liquefaction plant, and a re-gasification plant with a very high send-out capacity. Although costs are high, peak shaving means that large pipelines do not need to be built to handle maximum yearly demand for one day, and then remain over-engineered for the other 364 days, so they are more economic than the alternative. The average withdrawal rate of existing OECD countries' peak shaving units is 21% of working volume per day (min: 8.2%, max: 39.7%).

Line-pack is the buffer which the gas transportation system provides itself and is usually used to balance input and output of the transportation system on a daily basis. During hours of low demand, the pressure in the grid can be slightly increased, in a way that in hours of higher demand the excess gas can be released.

19. In gas markets priced from gas fundamentals, the price differential between a summer injection season and a winter withdrawal season can be hedged in advance, whereas this is impossible for a short-term storage site because daily prices are not tradeable for a year.

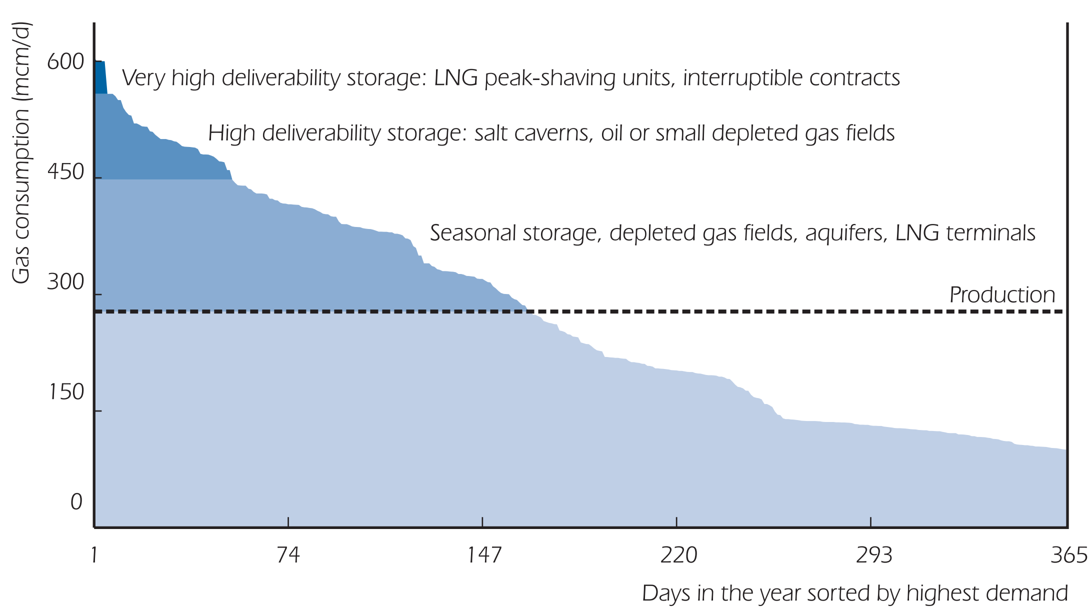
Use of various storage types

Figure 46 shows how various types of storage can be used to ensure reliable gas supply when it is needed. It is based on the ideal situation where all demand information is known and all types of storage would be available.

Figure 46 takes the consumption data from Figure 43 and sorts all the days of the year by demand. The days with highest demand are on the left, those with lowest demand on the right. A constant supply (production or imports) is indicated by the dotted line. For about half of the year, supply is higher than consumption. During this period gas storages can be filled. When gas demand is higher than gas supply (left side of the figure), storages are drawn. The more or less predictable summer/winter variations are covered by depleted gas fields, aquifers and LNG terminals when the required volumes are large. Salt caverns or smaller depleted fields handle the more incidental demand peaks, and the extreme peaks are covered by peak shaving units. This is dependent on the existing geological and market conditions; the latter are changing particularly fast in Europe.

In liberalising markets particularly, there is an important shift in the use of storage, which is related to the operation of the liberalising power market. One of the defining features of power is that it cannot be efficiently stored, so generation has to be very flexible to meet demand in real time. Where hydro is not available or fully used, gas or oil is the only source of generation able to meet this volatile demand. This means that consumption

Figure 46 **Use of various gas storage types, illustrative example**



patterns for gas-fired generators are becoming more volatile. Short-term storage is ideally placed to deliver gas according to the dynamic patterns needed by the power industry, so it is in high demand. It is clear from the more liberal markets that more salt cavern storage is being built than seasonal storage, which has worried some policy makers. In fact, small cavern storage is needed and will have a beneficial effect on both the gas and power markets.

In open gas markets, flexibility is absolutely essential, so access to storage capacity should be subjected to third-party access. This means that storage can be used by any player in the market (shipper) who has contracted capacity, usually through annual auction. Whereas certain players buy storage capacity to support their other commercial operations, gas traders buy storage to take advantage of the volatility in the gas market. The types of standard trade might be a seasonal spread, which locks in the price difference between the summer and winter futures or swaps prices to make risk-free[20] return on a long-term storage, or weekday/weekend spread, which does the same thing for a shorter-term storage. The benefits of this method are that it ensures that the maximum use is made of the asset, and it encourages flexibility and optimisation. If the annual auction price paid increases year-on-year, this is a sign that the volatility in the market is increasing, and that more storage is required. At some point, the price paid is enough to remunerate a new facility, and so one is built to take advantage of the opportunity. Meanwhile, the action of traders on the market is to dampen market volatility through their actions. Over the long term, the system tends to a dynamic equilibrium, whereby the number of storages is balanced against the volatility of the market. This represents the most cost-effective balance.

The downside to this method of operation is that it relies on market signals for optimisation, so if those signals are less than perfect, the asset might be incorrectly used. Transparency is, therefore, a key factor in ensuring efficient development and deployment of storage. Reliable information on storage levels, delverability and gas prices will enhance performance of the gas market and optimise storage use.

Strategic gas storage

Strategic gas storage is defined as storage, which is not used for commercial purposes. This usually means that the storage is under the direct control of a government. As such, it is not used to match supply and demand under normal business conditions, but is reserved for some emergency event defined by the government. While the IEA does not manage strategic gas stocks, IEA oil stocks can be released by governments at times when the market is not able to match supply with demand due to extraordinary conditions, such as after a severe supply disruption or other emergency. The most important differentiating point is that strategic stocks are not for the purpose of responding to price signals, and

20. While often referred to as risk-free, the correct term should be financially risk-free, as operational risks still exist.

Box 5 **Gas storage is different from oil storage in several key respects**

Oil can be transported in and to a consuming country by a number of means – including tanker, truck, pipeline or rail, but gas is almost entirely confined to existing pipelines, resulting in much lower flexibility of release. Being a globally traded market, oil stocks can be released, for example, in the United States to counter a supply disruption in Japan. Such an action with gas stocks would not, at this time, allow regional gas markets to re-balance. Gas stocks located in one area may not necessarily be well placed to alleviate supply shortages in another, because pipelines are not usually built to transport gas against the normal flow direction. The availability of suitable gas storage sites varies from country to country, whereas oil storage is much less dependent on geological conditions. Gas costs up to 10 times more than oil, both to store and to transport. The percentage deliverability per day of the larger gas stocks is comparable to those of larger oil stocks. Other demand-side measures exist to manage gas emergency situations, such as interruptible contracts, fuel switching and other emergency planning. The relative cost effectiveness of these measures varies from country to country.

should, therefore, stay separate from the market under normal conditions. The IEA has mandated the release of strategic oil stocks on only two occasions in its 32 year history.

Italy used its strategic gas storages in the winter of 2005-06, when demand outpaced supply. Spain also decided to maintain a mandatory level of gas storage (in the form of offshore LNG tankers) over the winter 2005-06 after supply disruptions to LNG deliveries in 2004-05 due to bad weather conditions. Hungary intends to build strategic gas storages of 1.2 bcm (equivalent to one month's consumption) which should be in operation by 2010. Strategic gas storage can, therefore, be an effective part of a suite of gas emergency measures in a country or region, with local geology being the main determinant of cost.

Storage development in OECD regions

At the end of 2004, OECD Europe had 103 underground gas storage facilities with a working volume of 64.7 bcm, or the equivalent of 48 days of average consumption. Three countries dominate the European storage scene, accounting for two-thirds of capacity: Germany (30% of capacity), Italy (20%) and France (17%). These countries together represent 42% of European gas demand, but are all largely dependent on gas imports.

Storage at LNG import terminals also plays a role in OECD European countries, particularly Belgium and Spain. There are 14 LNG re-gasification terminals in Europe with a capacity of 75 bcm per year and a storage capacity of approximately 1.4 bcm of gas (2% of European storage capacity).

North America has access to total underground capacity of 131.6 bcm, or 62 days of average consumption, 20% more than OECD Europe. Almost 90% of total North American storage capacity is located in the United States, while Canada, being an exporter, accounts for the remainder.

The use of underground gas storage is not common in OECD Pacific for several reasons. New Zealand is self-sufficient in gas, with most of its production coming from the Maui swing field. While the field is currently able to match the demand characteristics of the market, this situation is changing as the field declines. Australia is self-sufficient in gas, but because of the large distances between production and consumptions centres, it has developed four storage plants which account for about 5% of annual consumption.

The two largest gas consumers in the OECD Pacific region, Japan and Korea, are almost entirely dependent on LNG imports. This means that they have over-ground storage at the re-gasification terminals in reinforced concrete and steel tanks. Japan has 25 re-gasification terminals, with a total capacity equivalent to 8.3 bcm of gas, or 10% of annual gas consumption. When compared to LNG importing countries in other regions, this is a significant quantity of gas to hold in liquid form – usually prohibitive because of the cost. However, this is the only means to store gas in Japan. It is not used to manage seasonal demand swings but rather to manage the offload schedule of LNG ships.

Korea is in a similar position. It has four re-gasification terminals with storage capacity equivalent to 2.5 bcm of gas, or 9% of annual gas consumption. Korea has the added complication of greater city gas penetration than Japan compared with regular industrial use. This means that Korea has much higher demand seasonality. This is met through volume flexibility on long-term import contracts augmented by LNG purchases on the spot market.

While Spain, Korea and Japan all rely to a large degree on above-ground storage, these countries are also looking at developing longer-term sites. Spain is actively developing underground gas storage, and studies are underway in Japan and Korea to investigate the practicality of using lined rock caverns.

ANNEX A: LIQUEFACTION PROJECTS

Table 5 **Liquefaction plants in the world, existing and planned**

Country	Operator	Location	Capacity (mtpa)	Capacity (bcm per year)*	Status	Completion**
Abu Dhabi (UAE)	ADGAS	Das Island	2.8	3.8	Existing	
	ADGAS	Das Island	3.0	4.1	Existing	
Algeria	Sonatrach	Arzew GL4Z	1.1	1.5	Existing	
	Sonatrach	Arzew GL1Z	7.8	10.6	Existing	
	Sonatrach	Arzew GL2Z	8.4	11.4	Existing	
	Sonatrach	Skikda GL1 KII	3.0	4.1	Existing	
	Gassi Touil	Arzew	4.0	5.4	Engineering	2009
	Sonatrach	Skikda	4.5	6.1	Engineering	2010
Angola	Angola LNG Ltd	Soyo	5.0	6.8	Engineering	2010
Australia	Greater Gorgon LNG	Barrow Island	10.0	13.6	Engineering	2010
	Pluto LNG	Karratha	6.0	8.2	Planned	2010
	Darwin LNG	Darwin	3.3	4.5	Existing	
	North West Shelf train 1-4	Karratha	11.9	16.2	Existing	
	North West Shelf train 5	Karratha	4.4	6.0	Under construction	2008
	Inpex	Ichthys	5.0	6.8	Planned	2010
Brunei	Brunei LNG	Lumut	7.2	9.8	Existing	
Egypt	ELNG 1	Idku	3.6	4.9	Existing	
	ELNG 2	Idku	3.6	4.9	Existing	
	Segas	Damietta	4.5	6.1	Existing	
Equatorial Guinea	Marathon Oil	Bioko Island	3.4	4.6	Under construction	2008
Indonesia	Bontang	Kalimantan	22.3	30.3	Existing	
	Arun	Sumatra	6.5	8.8	Existing	
	BP Tangguh	Berau Bay	7.6	10.3	Under construction	2008
Iran	Pars LNG	South Pars phase 11	6.0	8.2 ?	Planned	2011
	NIOC LNG	South Pars phase 12	4.5	6.1 ?	Planned	2010
	Persian LNG	South Pars phase 13	4.5	6.1 ?	Planned	2010
Libya	NOC	Marsa Al Brega	3.2	4.4	Planned	2008
	NOC	Marsa Al Brega	1.3	1.8	Existing	
Malaysia	Malaysia LNG Company	Bintulu	22.7	30.9	Existing	
Nigeria	Brass LNG Ltd	Brass terminal	10.0	13.6	Engineering	2009
	NLNG Ltd train 1	Bonny Island	2.9	3.9	Existing	

*Original design capacity is in mtpa, bcm per year is calculated by multiplying the mtpa figure by a factor of 1.36

**Completion dates as quoted by companies

Table 5 **Liquefaction plants in the world, existing and planned (continued)**

Nigeria (continued)	NLNG Ltd train 2	Bonny Island	2.9	3.9	Existing	
	NLNG Ltd train 3	Bonny Island	2.8	3.8	Existing	
	NLNG Ltd train 4	Bonny Island	3.8	5.2	Existing	
	NLNG Ltd train 5	Bonny Island	3.8	5.2	Existing	
	NLNG Ltd train 6	Bonny Island	4.0	5.4	Under construction	2007
	NLNG Ltd train 7	Bonny Island	8.0	10.9	Engineering	2010
	Olokola LNG	West Niger Delta	20.0	27.2	Planned	2010
Norway	Snohvit	Melkoya Island	4.1	5.5	Under construction	2007
Oman	OLNG	Qalhat	6.6	9.0	Existing	
Peru	Peru LNG Co	Pampa Melchorita	4.4	6.0	Engineering	2009
Qatar	Qatargas I	Ras Laffan	9.5	12.9	Existing	
	Qatargas II	Ras Laffan	15.6	21.2	Under construction	2009
	Qatargas III	Ras Laffan	7.8	10.6	Engineering	2010
	Qatargas IV	Ras Laffan	7.8	10.6	Engineering	2010
	Rasgas I	Ras Laffan	6.6	9.0	Existing	
	Rasgas II train 3 and 4	Ras Laffan	9.4	12.8	Existing	2007
	Rasgas II train 5	Ras Laffan	4.7	6.4	Under construction	2007
	Rasgas III	Ras Laffan	15.6	21.2	Under construction	2009
Russia	Sakhalin Energy Investment Co Ltd	Sakhalin	9.6	13.1	Under construction	2008
	Tambei LNG	Yamal Peninsula	3.5	4.8	Planned	2010
	Shtokman	Barents Sea	15.0	20.4	Planned	2012
Trinidad & Tobago	Atlantic LNG Ltd train 1	Point Fortin	3.4	4.6	Existing	
	Atlantic LNG Ltd train 2	Point Fortin	3.4	4.6	Existing	
	Atlantic LNG Ltd train 3	Point Fortin	3.4	4.6	Existing	
	Atlantic LNG Ltd train 4	Point Fortin	5.2	7.1	Existing	
	Atlantic LNG Ltd train 5	Point Fortin	3.0	4.1	Planned	2009
	Atlantic LNG Ltd train 6	Point Fortin	3.0	4.1	Planned	2010
United States	Kenai LNG	Kenai	1.5	2.0	Existing	
Venezuela	PDVSA	Mariscal Sucre	4.7	6.4	Planned	2010
Yemen	Total SA Yemen LNG	Bal Haf	6.2	8.4	Under construction	2009
Total			**393.2**	**534.8**		
Total existing			**177.9**	**241.9**		

Source: Cedigaz, IEA data, company statements

ANNEX B: ABBREVIATIONS & ACRONYMS

ANWR	Arctic National Wildlife Refuge
ASEAN	Association of South-East Asian Nations
bbl	barrel
BBL	Balgzand-Bacton pipeline
bcf	billion cubic feet
bcm	billion cubic meters
b/d	barrels per day
boe	barrels of oil equivalent
CBM	Coal bed methane
CCGT	Combined-cycle gas turbine
CHP	Combined production of heat and power
CNG	Compressed natural gas
CNOOC	Chinese National Offshore Oil Corporation
CNPC	Chinese National Petroleum Corporation
EIA	Energy Information Administration
E&P	Exploration and production
EPC	Engineering, procurement and construction
EU	European Union
FERC	Federal Energy Regulatory Commission
FSU	Former Soviet Union
GHG	Greenhouse gas
Gt	Gigatonne (1 tonne x 10^9)
GTL	Gas-to-liquids
GW	Gigawatt (1 Watt x 10^9)
GWh	Gigawatt-hour
IEA	International Energy Agency
IPE	International Petroleum Exchange
IPP	Independent power producers
IOC	International oil company
kb/d	thousand barrels per day
kt	kilotonne
kW	kiloWatt (1 Watt x 1000)
kWh	kiloWatt-hour
LDC	Local distribution company

LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
mb/d	million barrels per day
MBtu	Million British thermal units
mcm	million cubic meters
Mtoe	million tonnes of oil equivalent
mtpa	million tonnes per annum
MW	Megawatt (1 Watt x 10^6)
MWh	Megawatt-hour
NBP	National Balancing Point
NDRC	National Development and Reform Commission
NEGP	North-European Gas Pipeline
NELP	New Exploration Licensing Policy
NIMBY	Not in my back yard
NOC	National oil company
NWS	North-West Shelf
NYMEX	New York Mercantile Exchange
OCGT	Open-cycle gas turbine
OCS	Outer Continental Shelf
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Petroleum Exporting Countries
TAGP	Trans-ASEAN Gas Pipeline
tcf	trillion cubic feet
tcm	trillion cubic meters
toe	tonne of oil equivalent
TPA	Third-party access
TPES	Total primary energy supply
TWh	Terrawatt-hour
USD	United States Dollar
WAGP	West African Gas Pipeline
WEIO	World Energy Investment Outlook
WEO	World Energy Outlook
WTI	West Texas Intermediate

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