NATURAL GAS MARKET REVIEW

2007

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Security in a globalising market to 2015

INTERNATIONAL ENERGY AGENCY

OECD

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The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six of the OECD thirty member countries. The basic aims of the IEA are:

- To maintain and improve systems for coping with oil supply disruptions.
- To promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations.
- To operate a permanent information system on the international oil market.
- To improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use.
- To assist in the integration of environmental and energy policies.

The IEA member countries are: Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Republic of Korea, Luxembourg, Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States. The Slovak Republic and Poland are likely to become member countries in 2007/2008. The European Commission also participates in the work of the IEA.

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

FOREWORD

In May 2005, IEA Ministers concluded that more focus on medium-term gas markets was required in order for the IEA to perform its prime mission: energy security. The Natural Gas Market Review (GMR) was launched in June 2006, at the World Gas Congress in Amsterdam. The annual GMR series is unique and unprecedented in looking at gas markets from a global rather than a purely regional or national perspective.

The GMR 2006 made some observations which are very important for energy security, noting for the first time that formerly separate regional or national gas markets are globalising. Specifically, they are being linked by rapidly expanding shipborne LNG trade. It also found that gas production from IEA member countries, which hold less than 10% of world gas reserves, is either stable or in decline while their gas demand, notably for power generation, is rising. Inevitably this means higher imports, over longer distances.

As well as looking at global thematic issues, the GMR 2006 reported on disruptive events in a number of distinct markets – proving that there is not yet one truly-global gas market. Such events included the impact of hurricanes in the Gulf of Mexico, shortages in Italy and the United Kingdom and of course the brief but widely reported interruptions of Russian gas supplies.

The GMR was well received by both governments and the wider energy community. For the 2007 edition, we have kept the same format, looking at global cross-cutting issues and individual market developments. We have also:

- extended our time horizon out to 2015, to better reflect the time horizons of the gas industry and to assess investment trends more accurately;
- highlighted more clearly regional demand and supply balances, again emphasising the role of flexible LNG supply in meeting regional demand;
- devoted much more attention to LNG, recognising that two-thirds of incremental IEA gas supply to 2015 will be in this form;
- included a section on short-term energy security policies and measures, with recommendations to member governments;
- published early results of our work on gas flows across borders to emphasize that greater transparency is essential to providing security in gas markets;
- summarised key regulatory developments which have a critical role in providing the right balance between assuring protection from monopoly abuse and encouraging much needed investment; and
- extended and deepened our geographic coverage of trends in IEA and other countries and regions, reflecting growing interdependence.

The GMR 07 reflects the events of the past year; it is written against a backdrop of high prices and warmer winters in the Northern Hemisphere that have not altered the underlying trend of gas demand growth.

In the current gas market, we see greater transparency as essential – from gas reserves to investment levels, gas flows, pricing and regulation. We will continue to work with companies and our member governments to improve information in all these areas and look forward to further progress in information exchange with non member countries, both gas producers and consumers.

We trust this 2007 edition of the Natural Gas Market Review will be as well received as the first. This book is published under my authority as Executive Director of the International Energy Agency.

Claude Mandil

ACKNOWLEDGEMENTS

The Review was prepared by the Energy Diversification Division (EDD) of the International Energy Agency, under the oversight of Noé van Hulst, director of the Office for Long-Term Co-operation and Policy Analysis (LTO). The Review was designed and managed by Ian Cronshaw, head of EDD. The lead authors were Daniel Simmons and Hiroshi Hashimoto.

Significant contributions were made from right across the IEA, including Fausta Geelhoed, Isabel Murray, Ulrik Stridbaek, Brian Ricketts, Christof van Agt, Ghislaine Keiffer, Catherine Hunter, Dagmar Graczyk, Francois Nguyen and Elena Merle-Beral. Timely and comprehensive data from Mieke Reece, Armel Le Jeune and Erica Robin were fundamental to the Review.

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The Review greatly benefited from input and overview from the following external experts: Terence Thorn, Sybe Visser, Manfred Hafner and Gi Chul Jung, the latter two under the aegis of the International Gas Union (IGU). However, the final responsibility for the Review lies with the IEA.

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KEY MESSAGES

1 *Natural gas is becoming an increasingly global commodity; developments in previously separate regional gas markets can no longer be considered in isolation.*

2 *To 2015, investment is a more serious concern than identified in the* Natural Gas Market Review 2006*. Current bottlenecks in* **upstream** *production and LNG liquefaction capacity are tightening.*

3 *Continuing regulatory uncertainty is the primary factor slowing* **downstream** *investment, especially in IEA Europe, in both national and international pipelines, as well as storage.*

4 *A year of generally mild winter weather in 2006 reduced gas demand in IEA countries, disguising the underlying trend of very tight markets.*

5 *Gas demand for power generation is still strong, growing in the United States by 6.5% in 2006. Policy uncertainty is slowing a revival of coal-fired and nuclear power, despite extensive plans.*

6 *Gas security is visibly deteriorating in IEA member countries. In the* **short term***, governments need to elaborate gas emergency policies, and evaluate them in an international context.*

7 *Short-term emergency policies need to be based on a suite of measures, which might include strategic storage in the right circumstances, but such storage is not "the silver bullet" for gas security.*

8 *In the* **longer term***, gas security will be served by more efficient gas production and use; more investment; improved domestic market designs; increased transparency of flows and investments; and diversification of energy sources, suppliers and supply routes.*

9 *Despite a mild 2006, gas remains vulnerable and expensive.*

EXECUTIVE SUMMARY

Gas goes global

Total gas output in IEA countries is falling, while demand is rising. IEA countries are becoming more dependent on inter regional trade, with this trend most marked in Europe. While the North American region has traditionally been concerned with pipeline gas, and the Pacific market with LNG, neither can now afford to ignore the global picture. North America is preparing to import LNG from both Pacific and Atlantic producers, while Pacific consumers have sharply increased LNG imports from Atlantic markets as some traditional Pacific suppliers have been unable to meet contracted demand. IEA Europe will import increasingly large volumes of both LNG and pipeline gas, so what happens in this region is of paramount importance to all regions of the world. If investment in pipeline gas does not develop as anticipated, (and there is cause for concern in this regard) pressure on both the Atlantic and Pacific LNG markets will increase.

LNG production capacity is growing, from 240 bcm in 2005 to 360 bcm by 2010 (in line with the 2006 Natural Gas Market Review, GMR 2006) and, by 2015 to 470 bcm, potentially as high as 600 bcm, **but capacity increases after 2010-12 depend critically on new projects being sanctioned soon**. Regasification capacity is growing rapidly, although some countries and regions need to improve competitive forces in their domestic markets if they are to take advantage of the diversity provided by LNG.

By 2015, LNG is set to provide almost a quarter of OECD gas demand, but will contribute relatively little to non-OECD energy demand. Despite the traditionally slow pace of developments in LNG markets, the business is changing rapidly. Newly-negotiated and recently-renewed long-term contracts are responding to the effects of globalisation seen in the more price responsive short-term LNG market. The rapid growth in LNG use and its greater flexibility is already beginning to create a global market for gas. This process has accelerated over the last year, compared to expectations of the GMR 2006.

Due to its liquidity and depth, the North American market has provided the “price to beat” for the increasing volumes of price-sensitive LNG cargoes. Nevertheless, LNG importers in the Pacific and European regions remain able to outbid the United States in order to secure incremental supplies due primarily to differences in domestic market structure. The United States price (usually indicated by the Henry Hub) therefore seems to be setting a floor price for price-sensitive LNG. During periods in 2006, a correlation between Henry Hub and prices in the United Kingdom became apparent, whilst some long-term LNG supply contracts are now indexed to the Henry Hub.

Investment outlook worsens

Investment in the gas sector is a serious cause for concern, having worsened in comparison to the GMR 2006. Current upstream investment to 2015 is considerably below the amount required, with particular weakness in several regions. Gas investments everywhere are suffering higher costs and construction delays, in keeping with energy investments generally, although proposed LNG projects seem especially affected. A selection of these LNG projects shows production delays averaging almost a year, with average cost overruns of more than USD 2 billion per project. Furthermore, only one major new LNG liquefaction project has been sanctioned in more than a year and a half, a marked slowdown compared to previous years. Reports pointing towards the formation of a gas producers' association, analogous to OPEC, will do little to improve this situation.

The global demand for raw materials and talent has pushed up costs (dramatically in some cases) and reduced the effectiveness of each investment dollar spent compared to the situation reported in the GMR 2006. As well as affecting existing projects, increasing costs have been blamed for the postponement and cancellation of significant new developments worldwide. At the same time, the companies with the skills to deliver these increasingly complex projects are seeing reduced access to reserves. Encouraging production in IEA countries, in particular a renewed focus on producing from "fallow" (economic but undeveloped) fields, could help take some of the pressure off non-IEA investment in the short to medium term.

There is a distinct deficit of new long distance pipeline investment in the period to 2015, noting that investments in transportation over increasing distances show a distinct preference for LNG. Regulatory uncertainty and NIMBY ("not in my backyard") issues continue to slow investment in downstream pipeline and other infrastructure, especially when borders must be crossed. Within many jurisdictions, **regulatory uncertainty is slowing investment**.

Storage investment seems to be lagging substantially in IEA Europe, but progressing well in IEA North America. Investment in downstream transportation and distribution networks is also behind, particularly in the IEA European region.

Investment in LNG shipping is running ahead of requirements through to 2015, but this additional capacity will add necessary increased flexibility to the LNG industry. Similarly strong investment is occurring in regasification capacity within each IEA region which will also contribute to flexibility, although in Europe many new terminals are yet to be sanctioned and geographical imbalances persist.

Gas demand drops in 2006, but gas remains expensive

An unusually mild winter in 2006 had a strong dampening impact on gas demand for residential use worldwide. In North America and North West Europe, prices responded to the decrease in residential demand and consequent record inventory levels by falling well below expectations in the GMR 2006. Prices have been below oil parity, resulting in increased substitution away from oil products in stationary applications. A similar substitution effect has occurred in Japan and Korea for different reasons. In the majority of IEA European countries, gas prices remained relatively static, reflecting their link to oil prices.

In the medium term, forecasts of tight supply underpin **high gas price expectations**. Gas demand growth looks set to remain strong, although a little weaker than in the GMR 2006, reflecting these expectations as well as increased concern over security of supply. Overall, gas prices in all IEA regions are still considerably higher than the level of USD 4/MBtu or below, which were seen as recently as 2002. Prices in 2006 ranged from USD 6.50/MBtu in North America, USD 7/MBtu in Japan, USD 7.40/MBtu in the United Kingdom, and USD 8.30/MBtu at the German border. Gas is cheaper than oil, but expensive when compared with coal.

Gas-fired power demand stays strong

Gas-fired power remains the default option for new power generation. In Europe, almost two-thirds of new electricity plant under construction is gas-fired. In North America, the proportion is half. Demand for new gas-fired power generation capacity continues to grow as political commitments in some countries to avoid or phase out nuclear and reduce carbon emissions have left gas as the default option. Uncertainty over climate change policy is slowing investment in new coal-fired plant in Europe and to a lesser extent, North America.

There are large numbers of new coal and nuclear plants planned, but construction needs to start soon if new plant is to be operational before 2015. Renewables cannot fill the gap in this timeframe; to the contrary, increasing shares of intermittent renewables such as wind may increase the need for flexible gas-fired power as back-up. The growing interdependence of gas and electricity is raising concerns about security, reliability and competition because gas increasingly meets electricity demand peaks, notably in summer, where an increasing number of IEA countries are experiencing peak power demand. In many regions, gas-fired plant sets the price of electricity a significant proportion of the time. Expensive gas therefore means expensive electricity. For these and many other reasons, policy makers must appreciate the growing intertwining of gas and electricity industries, and design markets and regulatory systems accordingly.

Gas security is deteriorating

The GMR 2006 highlighted the growing dependence of IEA countries on gas imports. The situation has continued to deteriorate over 2006, only alleviated by weakening demand from mild weather. There is concern about the rate of development of gas reserves in countries as diverse as Russia, Iran, Indonesia, and Bolivia. Moves towards a "Gas OPEC" will raise concerns further. At the same time, more gas is being transported over increasing distances in a more uncertain world. Hence the overall risk to gas supplies is growing. This heightens the need for short-term and long-term gas security measures. Gas emergency policies are needed to deal with short-term gas supply disruptions, while longer-term policies are required to ensure sufficient investment as well as increased diversity of suppliers, supply routes and energy sources, especially in the electricity sector.

The increasing links between gas and electricity offer both a threat and an opportunity regarding energy security. Efficient gas and power markets tend to reduce gas demand as prices increase, saving gas at times of high demand or low supply. In addition, some gas-fired equipment can continue to operate but switch fuel, reducing gas demand at the expense of oil. In addition, government-sponsored measures to save electricity "in a hurry" can be used to reduce power consumption, and hence gas demand, in the event of a shortage.

Consuming countries need to upgrade gas emergency policies to cope with possible supply disruptions. Strategic storage is one method of addressing specific security concerns. However, the high costs and limitations of strategic storage need to be well understood and their development and possible deployment should not undermine commercial storage investment. A suite of measures to address general security issues can be much more effective and efficient than storage alone. Such measures could take into account fuel-switching, interruptible contracts, demand restraint and storage where good sites are available. Growing globalisation in gas markets and expansion of electricity markets means that it is increasingly necessary to check the international interdependency of policies and market responses, particularly in a situation where they might be applied simultaneously. Possible impacts of national measures on wider oil and electricity markets need to be assessed.

In the longer term, open, transparent and fully functioning markets with strong cross-border links, offer important benefits in security of supply, competitive pricing and rational response in crises. Governments, especially in Europe, need to step up their efforts to ensure such markets develop and are maintained. Long term security is dependent on adequate and timely investment across the board in production, transport, pipelines and distribution. Ensuring that gas is used efficiently is paramount; the Alternative Energy Scenario set out in the *World Energy Outlook 2006* estimates that strong policy action to improve energy efficiency and promote low carbon alternatives can reduce global gas demand by between 4% and 5% in 2015, an amount equal to Russia's current gas exports to IEA countries.

The world "dodged a bullet" in 2006 but gas remains vulnerable and expensive

A very mild winter in 2006 and in some regions 2007 took significant pressure off gas demand in what was becoming a strong suppliers' market. This should not lure decision makers into a false sense of security. Supplies remain tight, and new projects under development are subject to rising costs and increasing delays. A return to more normal winter conditions in consuming countries will put strong pressure on gas supplies. Colder-than-normal weather in the winter (or indeed hotter weather in the summer) could quickly see supply difficulties re-emerge in some areas. There are very real concerns that upstream investments and long distance pipelines will not develop quickly enough to meet growing demand, especially if power generation investment continues to favour gas.

POINT OF DEPARTURE

The authors recognise that recent attention on 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 students and the interested general public. Bearing in mind this diversity of readership, the following 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.

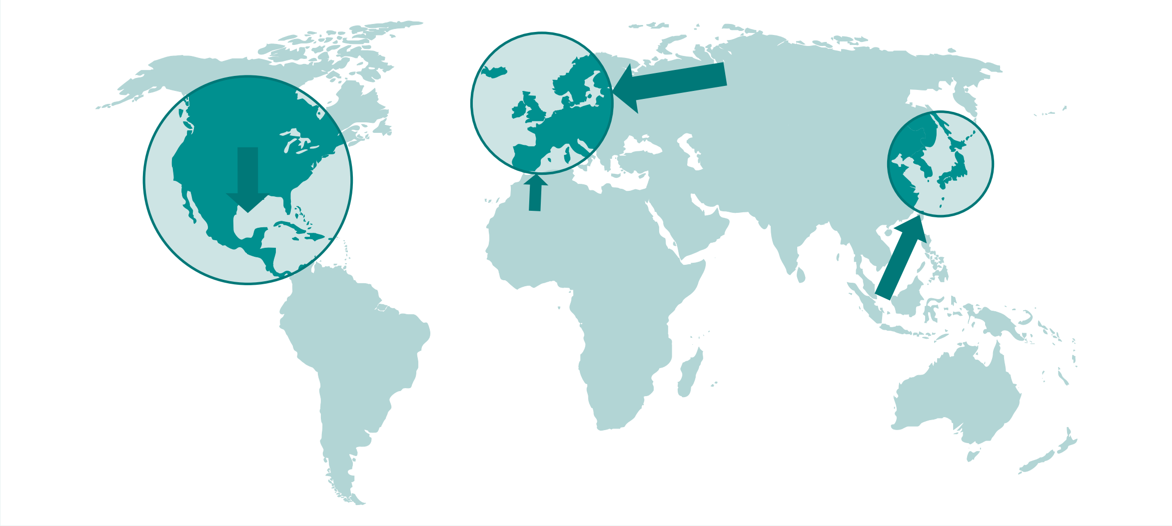
Natural gas provides about 20% of global energy supply, in a range of generally stationary uses, including industrial process heat, residential and commercial space and water heating, as well as, increasingly, power production. Gas use for power has more than doubled in the OECD over the last fifteen years. OECD countries account for 52% of gas use, transition economies, especially Russia, use about 23%, with developing countries accounting for the balance. In the latter group, Middle East and North African countries dominate; gas plays only a small part in meeting the rapid growth in energy needs of China and India.

Gas has tended to be used in the region where it is produced because of relatively high transport costs; less than one-sixth of demand is met by inter-regional trade. As production in OECD countries plateaus or declines, trade will become a more important feature of this market and hitherto regional markets will interact more strongly with each other.

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.

Figure 1 ***Traditional OECD countries' gas markets***



North America has been largely self-sufficient, with Canada being an important exporter of natural gas to the United States. About one-sixth of the gas used in the United States, the world's largest gas user, comes from Canada. Gas prices in this market are set through gas-to-gas competition, meaning that in times of oversupply, prices will be low and in times of tight supply, prices will be high. Prices can and have been quite volatile, especially in recent years. 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 23% of primary energy supply in North America.

IEA Europe is partly self-sufficient but relies for more than 40% of its gas supplies on imports, mainly from the former Soviet Union (about 23% of supplies from Russia, the world's largest gas producer and exporter) and Algeria. Intra-regional trade is also important, with Norwegian exports increasing and Netherlands and United Kingdom both exporting and importing though the UK has been a net importer since 2004. Generally the gas price in Continental Europe is directly linked to the price of oil. Hence gas prices will go up when the price of oil rises, irrespective of whether or not the supply of gas is tight. This also means prices have been generally higher than North American prices in recent years. Customers are less likely to adjust their demand since they do not receive timely or necessarily relevant price signals. On the other hand, suppliers are perceived to be less able to manipulate prices. Certain countries in Europe are now moving towards the North American system although at various speeds, with the North West European market as a prime example. Gas provides a quarter of IEA Europe's primary energy supply.

The Asian gas industry has developed from 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 for their gas supplies and gas is a relatively smaller proportion of the total energy supply of Asia-Pacific (14%), although gas is quite important in the Japanese power sector. Gas prices are linked to oil in Japan and Korea, but with a formula that differs from that of European gas users, so that at current oil prices, gas is cheaper than oil. In Australia and New Zealand prices are set by gas-on-gas or gas-on-coal competition.

Gas is transported through pipelines and as LNG

There are two principal ways of transporting gas from the production source to the market: through pipelines or in the form of LNG. Both are capital-intensive, with long construction times and 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 (LNG) is natural gas that has been cooled down to -160°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 units ("trains"). Once these trains have proven successful, both technically and commercially, more trains can be added at lower marginal cost ("brownfield expansion") if the gas resources are sufficient. After liquefaction, the gas is transported in specially designed ships. At the point of arrival the liquid is heated to return it to a gaseous state in a regasification terminal. LNG technology allows the development of large so-called "stranded" gas reserves that are often remote from major markets. High capital costs associated with LNG production and transport have encouraged a business model based on long-term, (typically 20 years) take-or-pay purchase obligations, agreed well in advance of plant construction (typically 5 years before first production). While still the rule, this model is beginning to be modified. More flexible, shorter term sales, such as seen in the oil trade, are now becoming much more commonplace. 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. The last five years have seen LNG production grow by about 50%, with growth set to continue at this rate to at least the end of the decade. More than 90% of output is destined for OECD markets.

Since the LNG ships are relatively free to determine their destination, 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. By 2015, some 25% of LNG output could be considered to be flexible; pipelines do not offer the same ability to market to different destinations. The cost of production of LNG is now low enough to be competitive in most parts of the world. A few liquefaction plants have now started to supply all three OECD regions, plus emerging markets; that is, they are marketing on a global basis. Competition for the approximately 10 to 12% of un-contracted production ("spot cargoes") is on a global scale. Since LNG is the marginal supplier in some markets it means that regional markets are beginning to be exposed to each other. The previously regionalised gas markets are interacting more strongly at a global level through both physical and price interactions, with important implications for change in the structures of gas consuming markets.

Gas consumption

As noted above, natural gas is used mostly by three sectors: Residential and commercial consumers, industrial consumers and power generation 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 is 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 over the short-to-medium term 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, for melting, as feedstock, or sometimes to drive their own small power plants. Gas demand in this sector is relatively stable and dependent 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 moving production to locations where gas is cheaper.

Apart from gas, the power sector uses coal, uranium, oil and hydro and other renewables to produce electricity. Gas has a variety of operational, commercial, and environmental benefits, not the least being a greenhouse gas emissions signature about half that of coal in newer plant. The development of the combined cycle gas turbine (CCGT) has been a technological and economic breakthrough, with efficiencies of gas fired power increased to almost 60% – the highest efficiency of any thermal generation. Gas use in the power sector has grown from one fifth of IEA gas demand to nearly one third since 1990. However, the price of gas can be a disadvantage to power companies, compared to the low marginal costs of sources such as nuclear or coal. This disadvantage can be offset if electricity prices are high enough; the difference between gas and electricity prices is called the "spark spread". Gas is particularly suited to meeting peak power demand, such as air conditioning demand on hot days, or as a supplement to intermittent sources, such as wind power. Gas and electricity markets are therefore increasingly interacting, which is particularly apparent in liberalised markets.

Units

The three 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

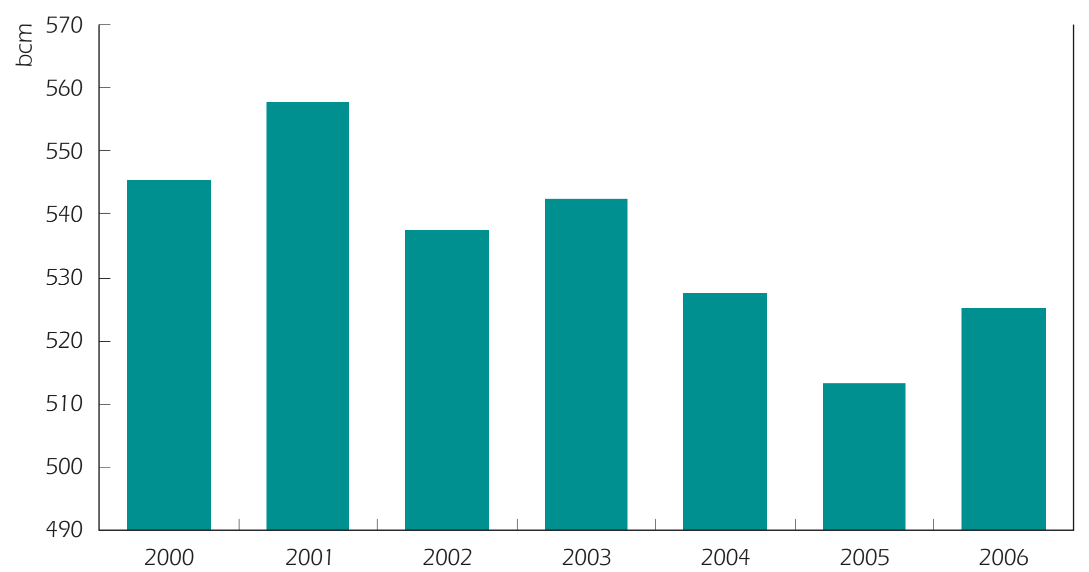
North American fundamentals

After a record 2005 hurricane season on the United States' Gulf Coast, two warm winters have seen gas demand fall dramatically. Demand in the industrial sector was affected first, but residential users also reacted to higher prices, albeit with a time delay. Production recovered from 2005, leading to record stocks and depressing prices dramatically from the expectations of late 2005. A return to more normal cold conditions in early 2007 has seen demand increase, and a record amount of natural gas was withdrawn from storage in February 2007, but stocks still remain slightly above the five-year average.

While gas demand for industrial and domestic use has fallen, gas use for electricity generation continued to grow, increasing 6.5% year on year in 2006. The North American market is starting to see a strong power demand peak in the summer – the summer of 2006 saw two consecutive weeks of natural gas withdrawals in late July and early August for power generation to run air conditioning units. These were the first-ever large scale withdrawals from storage during summer.

Though natural gas prices are well below the 2005 peak price of USD 15/MBtu, they are well above the 2002 price range of USD 3 - 4/MBtu, averaging USD 6.40/MBtu in 2006. According to the Energy Information administration (EIA), the benchmark Henry Hub natural gas price is projected to average between USD 7 - 8/MBtu in 2007 and 2008. This is predominantly due to inflationary pressures of a tight market for both rigs and skilled labour increasing the cost of drilling. North America is also experiencing declining production in some

Figure 2 United States' gas production



Source: EIA data.

mature regions, particularly in the offshore Gulf of Mexico which appears to be mimicking the faster-than-expected decline of gas production in the North Sea.

There is a strong correlation between gas prices in the United States and the number of wells drilled to explore and produce more gas. Since 2002, the number of natural gas wells drilled annually in the United States has increased by 90% to an estimated 32 000 drilled in 2006. The situation is much the same in Canada, with the number of new wells doubling to an estimated 17 700 in 2006.

Despite record gas drilling in the United States, production remains essentially flat. However continued expansion of unconventional production may be sufficient to hold the United States' production at constant levels or even expand production modestly for several more years. Nevertheless, with fewer natural gas reserves being added for every dollar spent on exploration and production, higher gas prices are needed to maintain production. These same high prices make LNG more attractive, exposing the North American market to global supply and demand trends and to some extent vice versa.

The United States natural gas prices have remained high enough to keep large infrastructure projects such as Mackenzie Valley and Alaskan North Slope pipelines alive. High prices increase the value of the gas in the market-place making the projects more attractive; however project cost increases driven by raw materials and labour cost inflation have tended to counteract this.

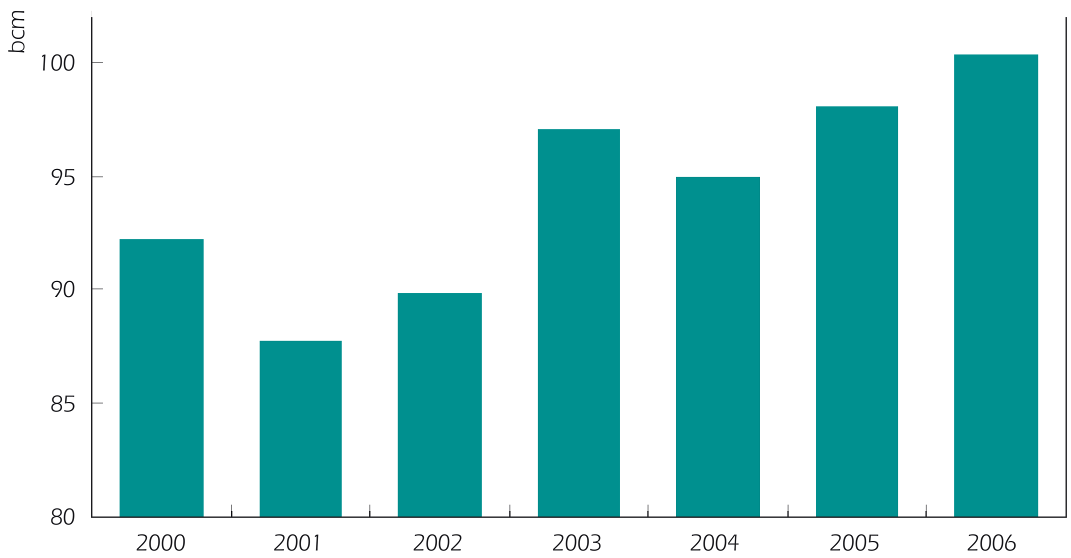
Although LNG imports declined again in 2006, most observers predict a more rapid increase in LNG imports in the future than projected a year ago. Regasification capacity will be adequate as 12 terminals with 150 bcm of capacity will be in place by 2012 (25% of 2005 demand). The geographic concentration of these terminals may however be an issue because most of the terminals are being built in the Gulf of Mexico. However, a substantial network of pipelines and storage fields required to move regasified LNG from terminals to market are already in place for these terminals.

During the next 10 years, the underlying use of natural gas to generate electricity is likely to continue to increase. New gas plants are increasingly being used for base-load generation (at all hours) rather than just to supply peak demand at only certain times of the day. This means that utilisation rates of installed gas capacity are expected to steadily increase from the 35% observed in 2006. By burning gas in underused plants, the United States will be able to increase power generation output without investing in new plant.

Estimates of likely gas demand in the power sector are highly dependent on progress in new coal build. About 10 GW of new coal plant is under construction, with much more planned. Progress on the latter may be affected by uncertainty over climate change policy, as in other IEA countries.

In Mexico, already facing natural gas shortages due to lack of investment, the virtual collapse at Cantarell – the world's second-biggest oil field in terms of output – at the start of 2006 will raise the pressure

Figure 3 Canadian gas consumption



Source: IEA data.

on Mexico's new President Calderon to open the country's closed energy market to foreign investors. In the absence of a turnaround in the hydrocarbon sector, gas imports look set to rise.

Canadian gas demand continues to grow as oil-sands projects start up, see Figure 3. These projects are major users of gas for the process of steam-assisted-gravity-drainage which essentially heats the oil sands deposits in-situ so that they flow into wells. Although Canadian gas production is projected to increase, exports of gas to the United States will fall as domestic demand grows.

As overall demand in North America grows rapidly, production is not projected to keep pace. The North American market is set to receive increasing volumes of gas from abroad. The United States and Canada will increasingly be influenced by gas supply and demand trends in the rest of the world, communicated through the LNG market.

Japan

New policy emphasising security

In May 2006, Japan's Ministry of Economy, Trade and Industry (METI) made public the country's New National Energy Strategy, which has energy security as its core. The policy provides numerical targets in: 1) energy conservation; 2) reduction of the share of oil in the primary energy mix; 3) reduction of the share of oil in the transport sector; 4) development of nuclear power; and 5) ratio of oil developed by Japanese companies. Those numerical targets were a clear message of the country's energy security concerns in the wake of changing dynamics of the Pacific energy market.

Procurement activities are at high levels

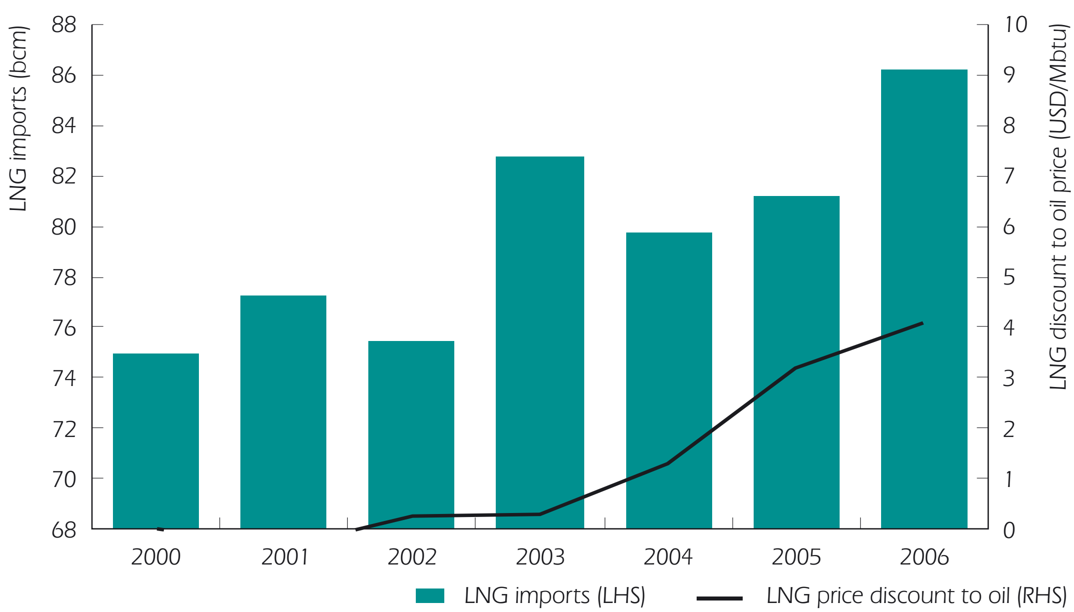
Japanese companies are busy procuring LNG for short-term supplies until 2010 to meet a sharp gas demand increase caused by fuel switching in the industrial sector as well as power generation demand resulting from nuclear problems. Supply deficit concerns are being felt because of some possible project delays. The S-Curve formula, under which many import contracts operate, keeps gas and oil prices in line within a "normal oil price" range, *e.g.* USD 16/bbl to USD 24/bbl. Outside this range, gas prices respond more slowly to oil prices, meaning that at USD 60/bbl oil, gas is substantially cheaper than oil per unit of energy.

Industrial customers who were still using oil-based fuels have responded to the recent price differential by converting to natural gas. This has driven LNG demand growth at the expense of oil. LNG imports to Japan under long-term contracts were over USD 4/MBtu cheaper than JCC oil prices (Japan Crude Cocktail, the average price of crude oil imported into Japan) in 2006. This price gap first appeared in 2002 and has widened since, as can be seen from Figure 4 (note that the spike in gas demand in 2003 was caused by increased gas-fired power generation which substituted for nuclear generation).

Major recent developments in procurement activities

The first Australian North West Shelf contracts that started in 1989 are set to expire in March 2009. The contracts involved eight Japanese foundation buyers for a total of 10 bcm per year (7.33 mtpa). Renewal

Figure 4 ***Increase in Japanese LNG imports driven by oil price differential***



Source: IEA data.

deals are being negotiated between the sellers' consortium and the individual buyers, rather than the buyers' consortium as was the case for the original contracts. The renewals are also being negotiated at reduced volumes for most of the buyers – at a total of 7 bcm per year (5.13 mtpa). They have shorter durations and possibly higher pricing arrangements.

Two contracts between Indonesia's Pertamina and six buyers in western Japan, amounting to 16.3 bcm per year (12 mtpa) and representing 20% of Japanese LNG consumption, are expiring in 2010 and 2011. Although the two sides agreed in principle to renew half of the volume in 2005, no final agreement has been reached yet. Now at least 4.1 bcm per year (3 mtpa), and potentially as much as 8.2 bcm per year (6 mtpa), is expected to be renewed. This issue was also on the agenda of intergovernmental talks when the Indonesian president visited Japan in November 2006.

Nine Japanese gas and power companies have contracted to purchase 6.7 bcm per year (4.94 mtpa) of LNG from the Sakhalin II venture in Russia's Pacific region. Two of the buyers expected to receive cargoes from 2007 having reached agreements with the venture in 2003. But when Shell, then majority owner of the project company, announced doubling of the project cost in summer 2005, it was also revealed that the commencement of the project would be delayed to 2008. After 18 months of controversy over the cost increases and revenue sharing, alleged environmental violations, and Gazprom participation, the foreign partners agreed to hand over a majority stake to the giant Russian gas company. The Japanese buyers are eager to see the 2008 start of LNG delivery as currently anticipated.

Some Japanese gas and electric power companies are negotiating with Qatar for long-term supplies from the Middle East producer's mega-trains, originally planned to supply LNG to the United Kingdom and United States markets. These volumes may be available in the short term as prices at NBP in particular are lower than expected.

Warmer than average winter

Much of Japan had higher-than-normal temperatures in the winter of 2006-07. The warm winter weather slowed down LNG consumption in Japan in the residential and commercial sectors, counteracting to some extent the increases in industrial and power use. National gas use in 2006 grew by 7.2%, mostly driven by a strong increase of 13% in industrial sector consumption, requiring the import of 86 bcm (62 million tonnes) of LNG.

Despite the relatively warm winter and consequent low demand for domestic heating, last quarter 2006 gas use seems to be increasing by some 14% year on year. In December 2006, Japan imported 7.3 bcm (5.33 million tonnes) of LNG, up 10.3% from a year ago. This was partly due to the ongoing substitution of gas in industrial applications, and partly because power utilities consumed more LNG to cover for nuclear generation which was scaled back.

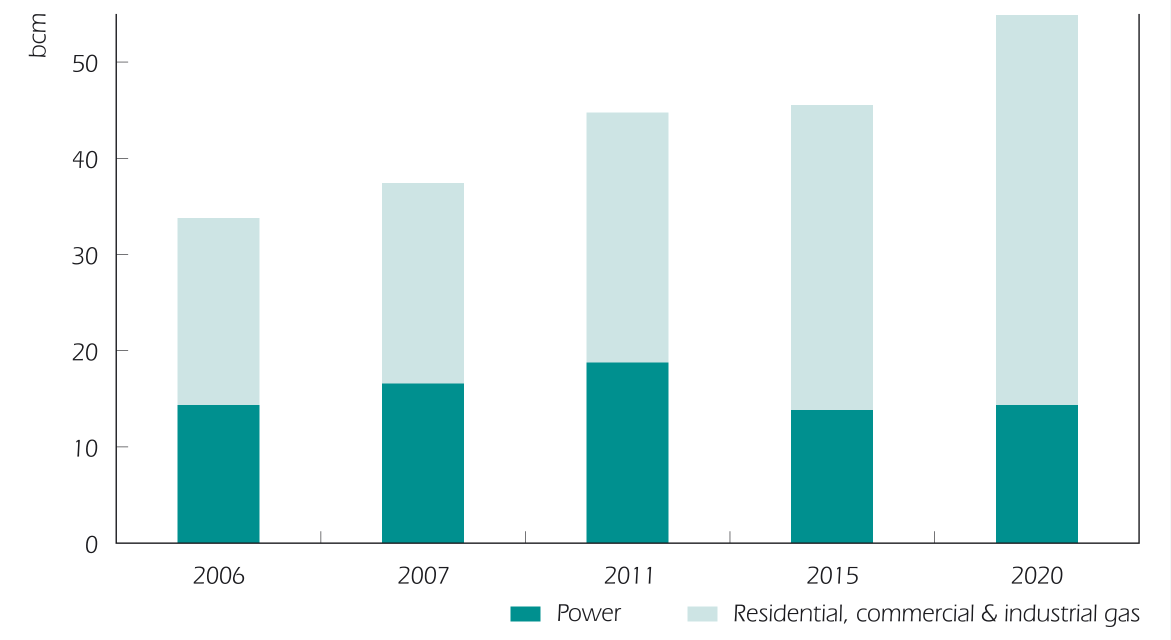
Korea

Korea's gas demand has been growing at 9% per year since 2000 and the country seems to be facing a looming supply gap. Korea Gas Corporation (Kogas) forecasts a shortfall of between 7.5 and 8.2 bcm per year (5.5 - 6.0 mtpa) in 2011 or 2012, which could prove conservative. Actual imports increased 55% from 19.9 bcm (14.6 million tonnes) in 2000 to 30.7 bcm (22.6 million tonnes) in 2005. In 2006, demand grew by 13.4%, to 34.8 bcm (25.6 million tonnes).

In December 2006, Ministry of Commerce, Industry and Energy (MOCIE) announced the country's Eighth Long-Term natural gas Supply/Demand Plan, for 2006-2020. According to the plan, LNG consumption is expected to grow at an average annual rate of 3.5% through 2020, to 45.6 bcm in 2015 and 54.9 bcm in 2020. Gas distribution for residential, commercial, and industrial use is forecast to grow at 5.4% a year, while the power sector consumption is forecast to remain flat at 2006 levels. Power demand growth is expected to be met increasingly through nuclear power expansion.

Kogas is trying to secure two long-term supply deals from Qatar, totalling 5.7 bcm per year (4.2 mtpa). The first one started delivery in 2007 and the other is expected to begin in 2009. These deals are the first long-term supply deals signed since the re-instatement of Kogas' status as "quasi-monopoly buyer" in the summer of 2006. This re-instatement of Kogas' status temporarily reverses decisions by the government in 1998 to increasingly

Figure 5 **Korea's eighth long-term natural gas supply/demand plan (2006-2020)**



Source: MOCIE.

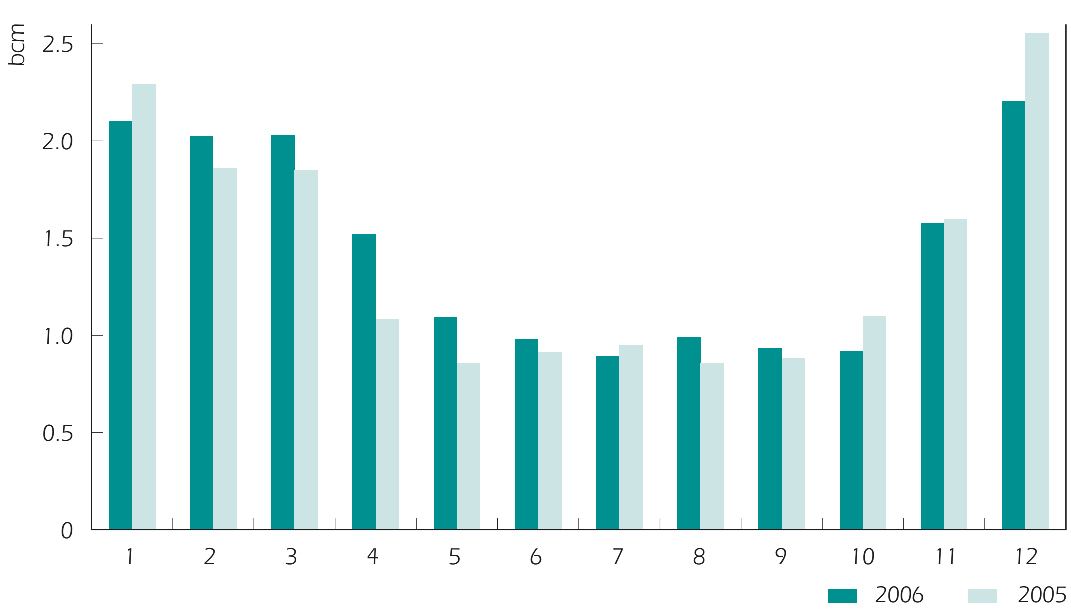
allow private companies to bypass Kogas and directly import LNG only for their own consumption. Only two companies, Posco and K Power have started importing LNG directly. A third, GS-Caltex also has permission but has not yet started receiving LNG deliveries.

In addition to the high year-on-year demand growth, seasonal differences in consumption are another important issue in Korea. Winter peak gas demand is up to 3 times summer consumption due to demand for space heating. In order to handle seasonal fluctuations, Kogas plans to increase LNG storage capacity by 69% from 2007 to 2013 (to 8 240 000 m^3). Kogas has also signed an initial deal with Oman's state gas company to build and operate two 200 000 m^3 tanks in the Sultanate. While Kogas has some "winter-weighted" contracts which deliver lower volumes of gas in the summer, storage continues to be useful in meeting seasonality.

Volatile LNG market in 2006

Sales growth in the first half of 2006 came from stronger demand in the power sector, leading to a demand surge of 10% compared with the same period in 2005. However, in the latter half of 2006, sales declined by 5% compared to 2005. Kogas' sales declined by 10% in the last quarter in 2006 compared to the same period in 2005 as demand was dampened by warmer-than-usual weather conditions. Despite the fact that the company's LNG imports for the year increased by 10% to 33.1 bcm (24.3 million tonnes), the company's gas

Figure 6 **Kogas' monthly gas sales**



Source: MOCIE.

sales for all of 2006 rose by only 2.8% from 2005 to 32 bcm (23.5 million tonnes) leading to an increase in end of year storage volumes.

Power generators bought 13 bcm (9.54 million tonnes) from Kogas in 2006, 8.2% more than 2005. But its year-on-year sales to retail gas companies in 2006 decreased for the first time, down 0.5% from 2005 to 19 bcm (13.96 million tonnes). The sales decline was due to warmer weather in the latter half of the year and a slowdown in economic growth.

As in many IEA countries, this winter has seen low domestic demand due to warm weather. In Korea, this has lead to high storage volumes and considerably less market tightness than in the previous winter (2005/06) when Kogas was extremely active in the spot LNG market.

Recent developments in Europe

The European commission and regulators body have both released reports in early 2007 on the state of the European gas markets. The introduction of competition in Europe's gas and electricity markets is an integral part of European energy policy which is directed at achieving the three closely related objectives of: a competitive and efficient energy sector, security of supply and sustainability.

The reports are seen as a critical litmus test in the run up to the much-vaunted "gas market opening" in July 2007, when the vast majority of domestic customers in the 450 million person trading zone become eligible to switch suppliers. It is however clear from the reports below that by July 2007 the vast majority of domestic customers will have little choice other than their traditional supplier.

On 10 January 2007, the eagerly awaited results of the competition report on the energy sector inquiry were released.[1] The key findings of this report are summarised below.

At the wholesale level, gas (and electricity) markets remain national in scope, and generally maintain the high level of concentration of the pre-liberalisation period. The current level of unbundling of network and supply interests has negative repercussions on market functioning and on incentives to invest in networks. Cross-border sales do not currently impose any significant competitive pressure, so incumbents rarely enter other national markets as competitors. There is a lack of reliable and timely information on the markets. More effective and transparent price formation is needed. Competition at the retail level is often limited. Currently, balancing markets often favour incumbents and create obstacles for new-comers. The size of the current balancing zones is too small, which leads to increased costs and protects the market power of incumbents.

As part of the sector enquiry, the commission launched individual investigations into a number of energy companies:

1. http://ec.europa.eu/comm/competition/sectors/energy/inquiry/index.html

- 16 May 2006. Investigations at the premises of gas companies in Austria, Belgium, France, Germany and Italy, and at the premises of electricity companies in Hungary;
- 29 May 2006. Investigations at the premises of electricity companies in Germany. The Commission has since announced proceedings against one of the companies concerned for allegedly interfering with the conduct of the investigation; and
- 12 December 2007. Investigations at the premises of German electricity companies.

The Sector Inquiry has identified a number of serious shortcomings which prevent European consumers from reaping the full benefit of competitive gas markets. The inquiry also noted the slow progress in integrating European markets more closely through expanded gas transmission links across national frontiers.

European regulators group for electricity and gas (ERGEG)

The European regulators group welcomed the sector inquiry results,[2] saying:

A single European energy market does not currently exist; nor does a comprehensive level regulatory framework to facilitate and oversee such a market. The existing regulatory picture is one of primarily national frameworks, although within a growing regional framework. Present EU legislation addresses only a limited subset of cross-border issues. The resultant "regulatory gap" creates uncertainty which acts as a barrier to the necessary investment.

The group proposes the following four key actions:

- The development of integrated single grids for the EU internal market in electricity and gas.
- Regulatory oversight at national and EU level including a European regulatory body.
- Democratic accountability.
- Effective separation of transportation and trade functions (unbundling).

There is a clear growing consensus that competition is inadequate within Europe, that investment in several key areas is lagging, and that regulatory uncertainty is a key cause. As a result of these weaknesses, Europe's energy security and competitiveness are suffering.

IEA energy policy reviews

It has been the IEA view that the majority of IEA European member countries in the EU could do much more to introduce competition in the gas sector. Our reviews of the following countries have recommended that additional steps be taken to increase liberalisation in the EU: Germany, 2007; Greece, 2006; Belgium, 2005; Spain, 2005 and The Czech Republic, 2005.

The IEA intends to publish a study in late 2007 devoted to the topic of gas trading in the Europe.

United Kingdom supply developments

In 2006, two new pipeline infrastructure projects were delivered in the United

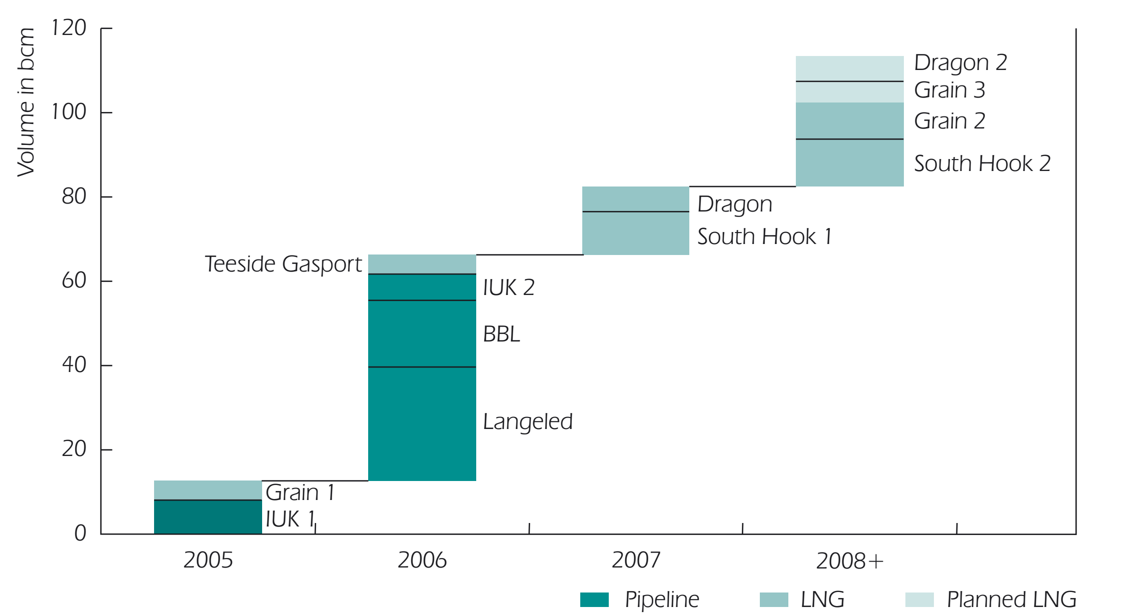
2. Available at http://www.ergeg.org

Kingdom market, both secured by long-term contracts indexed to the United Kingdom spot gas price (the NBP). The Langeled South and BBL pipelines were commissioned in October 2006 and December 2006 respectively. Two further infrastructure projects were also completed, the expansion of the Interconnector with Belgium and the Teesside LNG terminal, planned and built in under a year.

Langeled South is the largest underwater gas pipeline built and can carry 25 bcm per year (more than a quarter of United Kingdom demand) into the United Kingdom from onshore Norway. It is a groundbreaking achievement technically, but also financially – because it is part of the first large-scale gas production project in Europe that it is not financially underwritten by oil-indexed gas sales.

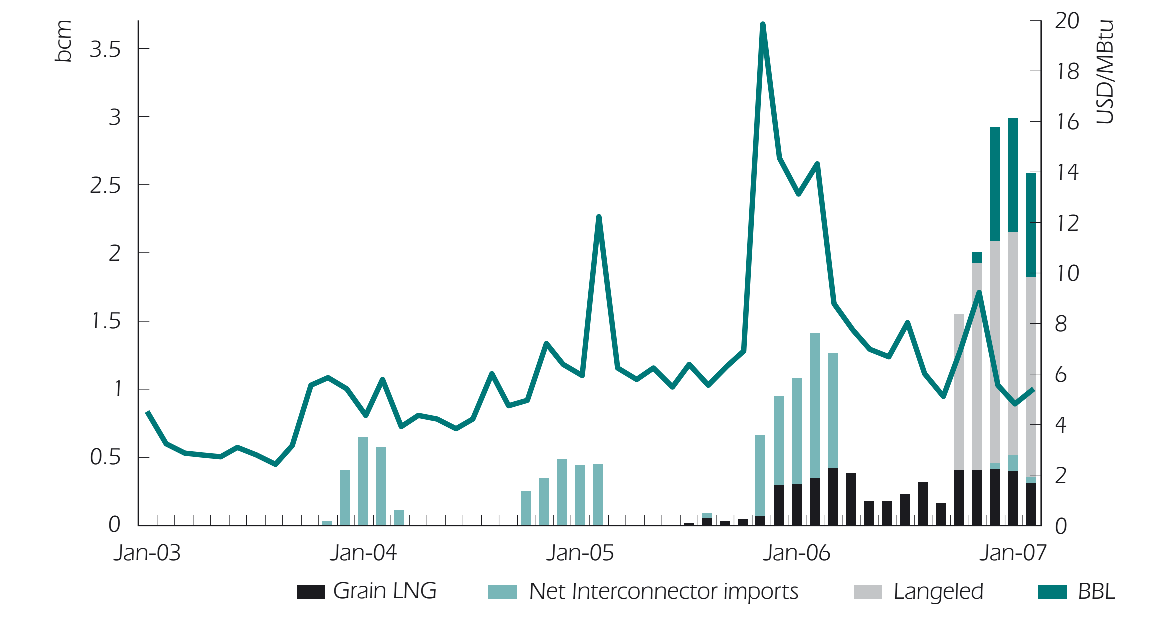
Langeled South will in late 2007 be connected to Ormen Lange gas production via onshore Norway. Because the pipe had no dedicated production at the time of commissioning in 2006, there was some uncertainty as to what the volume of flows through the Langeled would be. In the summer of 2006, futures prices for the next winter were trading at USD 18/MBtu because of this uncertainty. However, for now the pipeline is being fed by gas from the Troll area through a junction point in the Norwegian offshore system. The flow of gas through the Langeled pipeline has been consistently high ever since commissioning, causing a USD 2/MBtu drop in the monthly NBP price to around USD 4/MBtu. Indeed, the day that the commissioning flows came ashore in to the United Kingdom's system, the daily NBP price briefly became negative.

Figure 7 **New import infrastructure for the United Kingdom market**



Source: Published sources & company announcements.

Figure 8 **Investment reverses the trend of increasing United Kingdom winter prices**



Source: National Grid, IUK, the United Kingdom Government.

BBL is a uni-directional pipeline which can supply up to 16 bcm per year from onshore Netherlands to the United Kingdom. Physical flows are expected to be shaped in order to match higher prices in the winter which are caused by increased demand. There was some concern before the winter as to where the physical gas would come from for delivery through the BBL, particularly in a cold winter. However, the winter 2006/07 has so far turned out to be relatively mild across Europe, so continental players were left with excess contractual commitments which they were keen to offload.

Two smaller projects were also completed in time for a much anticipated winter price spike (which now seems unlikely). These were the United Kingdom/Belgian Interconnector expansion project (7 bcm per year) and a new LNG terminal (4 bcm per year). The LNG terminal is particularly noteworthy because it was built in clear response to the spot price signals from the last winter. Excellerate Energy applied for and built an LNG terminal in the North East of the United Kingdom. From conception to delivery, this LNG terminal took less than one year.

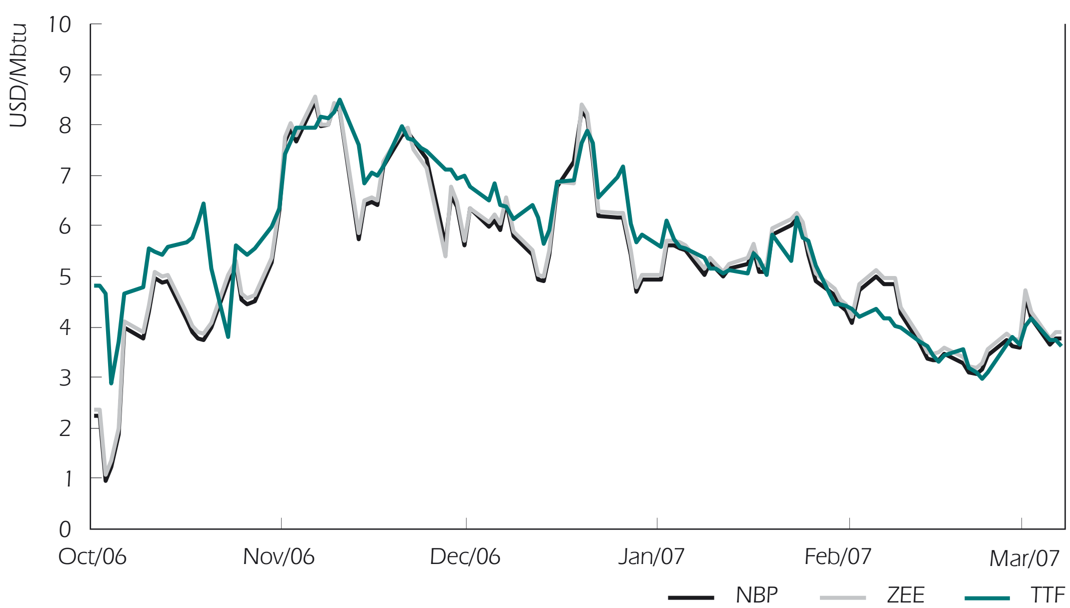
The flows in the Interconnector between Belgium and the United Kingdom have been negligible all winter, again proving that they do not respond to price differentials in the retail markets of Belgium (above USD 8/Mbtu) and the United Kingdom (below USD 5/Mbtu). The reason for this is that there is a disconnect between the wholesale price in Zeebrugge (Belgium) and the retail price charged by gas companies in Belgium. Belgian gas companies did not need more gas over the 2006/07 winter as temperatures have been mild, but they still charge customers prices near to record highs. In contrast to the winter 2005/06 when despite the price differential only 50% of capacity was used to flow to the United Kingdom, in 2006/07 the reverse seems to be true. Although the United Kingdom has enjoyed "half price gas" for the winter with minimal exports, this surely is further proof that there is a lot of work left to do before a real European gas market emerges.

A real "Northwest European" gas market?

The commissioning of the BBL linked the United Kingdom and Dutch markets physically for the first time, completing the triangle of pipelines between the Netherlands, the United Kingdom and Belgium. This was followed swiftly by price equalisation between the United Kingdom NBP and the Dutch TTF gas trading which looks on the surface as if an efficient market is operating. Unlike the United Kingdom, however, the majority of the Dutch and Belgian wholesale and retail markets are not based on the clearing prices at the exchanges, so wholesale Zeebrugge and TTF prices have only a limited effect on consumer prices within those countries. This explains the relative lack of liquidity compared with the NBP.

In the United Kingdom, the majority of supply companies buy gas at the NBP in order to sell to consumers. In the Netherlands and Belgium there are still many legacy contracts linked to other indices which allow the buyer to take a volume of gas within a predetermined range each day, month and year.

Figure 9 Northwest European exchange prices converge



If the winter is cold, demand will increase and the contracted volumes may not be sufficient for the continental suppliers. If the winter is mild, then the volumes contracted may be in excess of those needed. However, in both cases, the bulk of demand is met through bilateral contracts, with little liquidity in the exchanges.

To balance their portfolios, continental suppliers sometimes make use of the liquidity of the Northwest European market. In the winter 2005/06 the NBP was the balancing market for a region which found itself short of gas due to the cold – the price spiked as a result. In winter 2006/07, the NBP market has been the release valve for excess gas not needed due to the mild temperatures – the price has therefore been low compared to oil indexed prices.

Demand response: winter 2005/06

In the National Grid "Winter Consultation Report 2006/07" an analysis was made of the level of demand-side response experienced during the high-priced winter of 2005/06. As expected, industrial and commercial users were more affected than households for several reasons: the wholesale gas price makes up a greater proportion of their total energy bill; they are metered and charged regularly; and they often have greater individual flexibility.

In order to match supply and demand during the highest priced days of winter 2005/6, daily metered customers reduced demand by 27 mcm per day (on average). The majority of this response came from CCGT power stations reducing their gas consumption at times of off-peak electricity demand (coal lifted its share of power generating needs markedly in 2006, see the section on Gas-Fired Power), as well as firm gas consumers opting to sell their gas back to the market.[3]

Rising wholesale energy prices have had the expected delayed effect on end-user prices as these customers only see price increases every three months. Domestic consumers were subjected to gas (and power) price increases in 2006 with all the major retail suppliers increasing their prices at least twice. The effect of sustained high prices has resulted in a fall in demand that has continued into 2007. As wholesale prices have declined in winter 2006/07, so the major retail suppliers have slashed prices resulting in many residential users switching suppliers. The price reductions amongst the retail suppliers have resulted in a "gas price war" which was ongoing as this document went to press, with over 4 million customers switching supplier since the start of 2006.

Gazprom Algeria MOU

Sonatrach and Gazprom signed a memorandum of understanding (MoU) in August 2006, following a visit by Russian President Vladimir Putin to Algeria (accompanied by Gazprom CEO Miller). The visit, the first by a post-soviet Russian leader, was seen as a strong manifestation of resource-

3. Further information on demand-side market response can be found in the 2006/07 Winter Consultation document.

diplomacy from the president. The MoU covers "activities in the oil and gas sector: geological exploration, production, gas transmission and distribution network development, asset swaps, natural gas and oil processing and marketing."

Sonatrach has a long history of agreements with third parties. For its part, Gazprom, which has just entered the LNG marketing arena, has also concluded several agreements regarding LNG with Asian companies. Thus, both companies have been cooperating with various gas players worldwide and the MoU was not unexpected, particularly given President Putin's earlier visit.

The MoU raised some concerns from consuming countries: Gazprom and Sonatrach hold export monopolies in Russia and Algeria respectively. These two countries are the largest and fourth largest gas exporters globally, and two of the three largest exporters to the EU. Despite the concerns about potential export co-ordination as a result of the MoU, it should be borne in mind that the two companies could come to price (or other policy) convergence without such an agreement as they could simply adopt parallel behaviour. It seems more likely that in fact the MoU will result in (other) commercial and technological agreements.

In 2004, IEA-Europe depended for 34% of its gas on Russia and Algeria; Italy obtained 61% of its gas from these two countries. However, not only does Europe rely heavily on Russian and Algerian gas, it also constitutes the main market of Gazprom and Sonatrach – the dependency is two-fold. Algeria delivered 90% of its gas exports to OECD Europe; 70% of Gazprom's export volumes went to OECD Europe, making up some 85% of Gazprom's gas export revenues and about 60% of its total gas sales revenues. Italy alone bought 40% of Algeria's gas exports.

Europe and its principal suppliers are interdependent, but both are trying to diversify their portfolios as much as possible. Europe's gas security discussion has prompted European countries to redouble their efforts to diversify their sources of gas imports. Conversely, producers are naturally looking to other gas markets to hedge their dependence on European buyers. Gazprom is making efforts to diversify its own markets for its gas exports, targeting supplies to the North American and Asian markets. For its part, Sonatrach is looking to the United States and India.

Table 1 **Combined share of Russia and Algeria in Europe**

2004	IEA Europe	Italy	Spain	Turkey
Russian / Algerian gas imports as % of gas consumption	34	61	50	77
Russian / Algerian gas imports as % of total primary energy supply (TPES)	8	22	9	18
Russian / Algerian gas as % of input in power and heat generation	11	30	13	40

Source: 2004 IEA data.

There is much talk of possible collusion in the gas market, prompted by President Putin's equivocal reference to a possible gas cartel. The growing number of suppliers and energy sources means that any coordination, if planned, would be as difficult to implement as efforts to form cartels in other commodities. Unlike oil, gas has many substitutes in power generation and steam raising applications. The Gas Exporters Forum last met in Trinidad in May 2005; no meeting occurred in 2006, although one is scheduled in Qatar in April 2007, rekindling discussion of a possible natural gas version of OPEC. The Russia-Algeria agreement is likely to raise Europe's interest in energy diversification, in terms of suppliers and in terms of the overall energy mix. In addition, renewables, coal and nuclear power need to be maintained as viable alternatives to gas in the power sector.

Indonesia

Indonesia, which enjoyed the status of the world's largest LNG exporter for 22 years but lost the top spot to Qatar in 2006, has in recent years been cutting its contractual LNG deliveries because of a slower-than-expected rate of gas reserve replacement combined with dwindling feed gas production and growing domestic demand.

The production decline is most pronounced in the East Kalimantan fields that supply the Bontang liquefaction plant, although the Arun LNG facility has also been affected. As a consequence, Indonesia's share of global LNG trade has halved from its peak of 31% in 1999, to 14% in 2006. Indonesia's LNG is supplied on mostly long-term contracts, with about 63% going to Japan, 23% to Korea, and the remaining 14% to Chinese Taipei in 2006. Some Arun contracts are due for completion in 2007 while Bontang contracts are due over 2011 to 2018.

Ongoing problems in the investment regime and governance of Indonesia's energy sector have led to decreasing investment in upstream oil and gas production over the past decade. Such investment was needed to compensate for declining reserves in existing fields. In addition to the call on production to serve export commitments, the Indonesian government is also trying to increase the share of gas in its domestic energy mix. It has made clear that, in response to its gas supply-demand mismatch, its policy will focus on meeting domestic demand rather than exports.

In early 2005, Indonesia's state company Pertamina negotiated the rescheduling of some 51 cargoes of its total 450 cargoes under long-term contracts with Japan, Korea and Chinese Taipei for the year (each cargo typically holding 60 000 tonnes of LNG). In December 2005, the country's upstream regulator BP Migas and Pertamina advised that a total of 61 cargoes (52 from Bontang and 9 from Arun) would be cut from Indonesia's 2006 shipments. According to customs statistics of Japan, Indonesia sold 1.9% less LNG to Japan in 2006 than 2005, while – ironically – it earned 13% more, some USD 5.9 billion in 2006.

Indonesia currently plans to export 53 fewer LNG cargoes than contracted, representing a 12% reduction, in 2007. The cargo reduction equates to about 1.6% - 1.8% of the global total LNG trade.

Japanese buyers hope to renew contracts for half of the 16.3 bcm per year (12 mtpa) of Indonesian supply contracts set to expire in 2010 - 2011. Their combined contractual volumes of 16.3 bcm account for about 20% of Japan's annual LNG imports. The two sides started full-fledged discussions on contract renewals in June 2004 and agreed to key commercial terms for partial extension in September 2005, but no final agreement has been reached. At least 4.1 bcm per year (3 mtpa), and potentially as much as 8.2 bcm per year (6 mtpa) is expected to be renewed.

Pertamina announced in December 2006 that it would not extend a 2.0 bcm per year (1.5 mtpa) contract to Chinese Taipei's CPC Corp. beyond its end-2009 expiry date because Japan is being given preference. CPC has another contract of 2.5 bcm per year (1.84 mtpa) that expires in 2017.

Major project decisions in 2006

Some key investment decisions are among the developments during the period between this 2007 edition and the previous 2006 edition of the *Natural Gas Market Review (GMR)*. Decisions on large investments in the Shtokman and Sakhalin II projects in Russia will have very large impacts on the Atlantic and Pacific gas markets, respectively, while expansion of the fledgling GTL market hinges on only a few mega-investments.

Shtokman decision

The Shtokman field is located in the Arctic Barents Sea, a tough area for any major project development. The field itself is estimated to have 3.7 tcm of gas reserves and plans have existed for some time to export this gas to markets in Europe and North America targeting 2012.

In October 2006, Gazprom announced that it would proceed on its own with the giant Shtokman gas field development in Barents Sea rather than give 49% of the project to foreign players. Five Western companies had been short-listed for LNG development, and it was thought the chosen companies might be announced around the time of the G8 Summit in St. Petersburg in July 2006.

Gazprom claimed the five contenders had been unable to offer assets equivalent in scope and quality to the reserves of the

Table 2 Shtokman, status

Natural Gas Market Review 2006	Natural Gas Market Review 2007
Project partners (possible): Gazprom 51% + foreign partner(s) 49% (contenders: Statoil, Norsk Hydro, Total, ConocoPhillips and Chevron)	Project partners (possible): Gazprom (Sevmoreneftegaz) 100% for the moment, with foreign subcontractors
Transportation routes: Murmansk LNG targeting North American markets, 16 - 20 bcm per year (12 - 15 mtpa) starting 2012	Transportation routes: Pipeline gas source to Europe (via Nord Stream Phase 2) probably after 2015, with marginal LNG possibility

field. While the company insisted that LNG remains part of the development plan for the field, the company also said piping gas to Germany would now take precedence over shipping cargoes to North America, where Gazprom has not yet secured any firm capacity at existing or planned LNG receiving terminals.

Preceding this announcement, after his meeting with German Chancellor Merkel at the end of September, Russian President Putin mentioned the possibility of redirecting future gas supplies from Shtokman away from the North American market to the European market, suggesting that Russia could sell between 25 and 45 bcm per year from Shtokman to Europe via the Nord Stream pipeline across the Baltic Sea. In December 2006, however, President Putin reiterated that the subject of foreign participation in the project could be considered again if interesting proposals were to be made by foreign partners. In January 2007, Gazprom approached the five LNG finalists again, inviting them to work as subcontractors.

Sevmoreneftegaz, a wholly owned subsidiary of Gazprom, which holds the license to develop the Shtokman field, plans to review reserves in the Shtokman field in 2007. Although the total reserves figure of 3.7 tcm is not expected to change significantly, commercial reserves, which now total 2.9 tcm, are likely to be increased with new exploration results. The company says it would determine the capacity of a pipeline (supposedly to supply Russian domestic markets and also connecting to Nord Stream) and possibly a liquefaction plant for the project.

In Russian industry circles, it is suggested that initial production from Shtokman is unlikely to begin before 2015, instead of an earlier 2011 target. Though in the *GMR 2006* Shtokman LNG exports were tentatively marked for an expected date of 2011, given the unclear circumstances of the project, notably its location, it appears that little gas will reach markets from Shtokman before 2015.

Sakhalin II settlement

The Sakhalin II project is already being built on Sakhalin Island, developing gas and oil resources off the Russian Pacific coast, mainly targeting the Pacific energy markets.

In December 2006, Gazprom took over a controlling 50%-plus-one-share stake in the Sakhalin II export venture in return for a cash payment of USD 7.45 billion, putting an end to an 18-month saga over the project's massive cost increases and alleged environmental violations. The existing partners are left with halved stakes of the project company: 27.5% for Shell, 12.5% for Mitsui and 10% for Mitsubishi.

The production sharing agreement (PSA) for the Sakhalin II was signed in the mid-1990s when the country was in considerable financial distress. The PSA is seen by many Russians as unduly advantageous to foreign shareholders.

After the share-transfer agreement, Gazprom confirmed that all the supply commitments from the project would be met on time, starting in late 2008. Construction work at the planned liquefaction plant is on schedule to complete the

Table 3 Sakhalin II, status

Natural Gas Market Review 2006	Natural Gas Market Review 2007
Project partners: Shell 55%, Mitsui 25%, Mitsubishi 20%	Project partners: Gazprom 50% + 1 share, Shell 27.5%, Mitsui 12.5%, Mitsubishi 10%
Transportation routes: 13 bcm per year (9.6 mtpa) LNG deliveries in 2008 to Japan, Korea and Mexican west coast Controversies over cost increases, alleged environmental violations	Transportation routes: Gazprom confirming all supply commitments would be met on time, starting in late 2008 The cost and environmental issues apparently being resolved

first 6.5 bcm per year (4.8 mtpa) train in 2007 and the second train of the same capacity six months after that. Since feedgas will not be available until 2008, the trains are to be commissioned by importing LNG, regasifying and reliquefying the gas. The project has already signed up long-term customers in Japan for 6.7 bcm per year, Korea for 2.0 bcm per year and Mexico for 2.2 bcm per year. Deliveries are still expected to start as scheduled.

Gas-to-liquids (GTL)

The potential demand for GTL products is huge because they can be used in the gas oil and diesel oil markets which represent 13 mb/d of OECD consumption. GTL diesel itself has two market applications for cleaner transport fuels; 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.

In the *GMR 2006*, Gas-to-Liquids (GTL) capacity planned and under development for commercial scale projects exceeded 773 000 b/d, with the bulk of these investments planned in Qatar. In 2006, Qatar placed a moratorium on new development of its reserves in the North Field and is awaiting the results of technical studies into the performance of the field. Adding the effects of this moratorium to other recent developments in the global gas industry, the future of GTL now looks more uncertain than a year ago.

During the past year, GTL projects' costs have been the victim of rapidly increasing costs endemic in the energy industry. Early in 2007, Exxon announced that it had cancelled the 154 000 b/d Qatari plant which it postponed in 2006 due to the moratorium on Qatari gas production. As of February 2006, the costs of Pearl GTL had doubled from USD 5 Billion to USD 9 Billion. Shell announced in January 2007 that it has broken ground on the Pearl GTL project, but that the cost for this project had now increased to USD 19 Billion. Other developments have changed the picture of the following Table 4 which has been taken from the *GMR 2006*, but updated as of February 2007 with the changes highlighted.

The economics of GTL processing can be summarised as the value of the product and the cost of production: The value of the product depends on market prices of the liquids produced and as such is largely driven by the expectations of better fuel standards in OECD countries. The principal costs include plant construction, gas feedstock and process efficiencies, such as product yields and energy efficiency of the plant. There are also opportunity costs which can be summarised as the value of alternative products such as LNG or domestic gas uses, as well as the value of delaying production.

Based on industry estimates in the *GMR 2006*, the capital costs for historical GTL projects tended to be in a range of between USD 20 000 to USD 30 000 per daily barrel of capacity. With the announcement by Shell and Exxon that costs have increased up to USD 135 000 per daily barrel of capacity, it is clear that economics of GTL production have changed rapidly.

Meanwhile, price expectations for LNG in the United States have decreased even as LNG price expectations for Europe and Pacific markets have increased. Price expectations for LNG projects affect the netback on LNG facilities which compete for the feed-gas that GTL projects use. GTL processes typically require about 10 MBtu of gas to produce one barrel of fuel. Thus, a change in the opportunity cost of gas feedstock of USD 0.50/MBtu would shift

Table 4 **Global GTL projects**

Project name	**Capacity (kb/d)**	**Status (2007)**	**Company**	**Location**
Bintulu	14.7	Existing	Shell	Malaysia
Mossel	25	Existing	PetroSA	South Africa
Oryx	34	**First product**	Sasol, Chevron and Qatar Petroleum (QP)	Qatar
Escravos	34	**Under construction**	Chevron/NNPC	Nigeria
Pearl	140	**Under construction**	Shell, QP	Qatar
Oryx (expansion)	76	**Advanced planning**	Sasol, Chevron and QP	Qatar
Tinhert	36	**FID postponed**	Sonatrach	Algeria
Palm	154	**Cancelled**	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

Source: IEA data, company statements.

the synthetic fuel production cost by around USD 5/bbl.

Russia/Belarus gas and oil negotiations

In 2006, Russia and Belarus negotiated at the political level over several intermingled issues: gas prices, gas transit tariffs and oil taxes. About 20% of Russian gas exports (40-44 bcm) and nearly one third of Russia's oil exports (31-33 million tonnes per year) transit Belarus. Belarus imports nearly all its gas (20-21 bcm) and approximately 90% of its crude oil from Russia.

In 2006, the Russian government sought to eliminate special treatment for Belarus in terms of oil and gas pricing and move to market relations, as it has been doing systematically with all CIS countries (see later section on Russia). Belarusian officials were concerned about the economic implications of these moves. The parties reached an agreement on gas prices and transit tariffs on 31 December 2006 (see Box) but the oil negotiations continued in 2007.

The growth in gas prices and the loss of oil tax preferences are already having serious economic implications for Belarus. This also raises concerns about Belarus' ability to pay the increased gas bill. There are concerns that it may in fact build up a debt to Gazprom – in past negotiations with other countries, Gazprom has been able to convert such debts to downstream equity.

Belarus has been trying to offset the price increases by introducing various measures. For example, it renegotiated with Russian companies the terms of crude oil supply from February 2007. Belarus also raised oil transit tariffs by over 30% in February 2007 and announced a plan to charge a duty for the use of land under oil and gas transportation pipelines.

While the gas agreement was reached just in time (2 minutes before the threat to shut off supplies expired) the oil negotiations carried on through 2007, resulting in oil delivery problems on the Belarus pipeline. While the oil negotiations are now over, the stability of both the gas and oil agreements between Russia and Belarus is uncertain.

Box 1 Gas agreement of 31 December 2006

- Gazprom will charge Belarus USD 100/1 000 m^3 (USD 2.65/MBtu) for gas supplies in 2007. The price will grow to the Western European level (minus the transportation component) by 2011: Belarus will pay 67%, 80% and 90% of the European price in 2008, 2009 and 2010.
- The fee for transiting Russian gas through Belarus grew from USD 0.75 to USD 1.45/1 000 m^3/100 km (USD 0.02 to USD 0.04/MBtu/100km).
- Gazprom will buy a 50% stake in the state-run Belarusian gas transportation company, Beltransgaz, for USD 2.5 billion, paying for it in cash over four years.

INVESTMENT

- Insufficient investment in the gas sector to 2015 is a serious cause for concern – the existing bottleneck in the gas market is in worldwide gas production, and this is likely to get worse.
- For a selection of 13 LNG projects analysed, there is now an average delay of nearly a year along with an average increase of costs of some USD 2.26 billion per project, resulting in a considerably worse situation that expected in the *Natural Gas Market Review 2006* (*GMR 2006*).
- There is also a distinct deficit of investment in new transmission over the period to 2015 driven particularly by regulatory and political uncertainty. Investments in transportation over increasing distances show a distinct preference for LNG over new pipelines in order to mitigate transit risk.
- Storage investment is also lagging substantially in IEA Europe, where market price signals are largely absent. It is progressing well in IEA North America and the UK where signals are strong.
- IEA countries need to ensure that their domestic gas markets are flexible, or they will miss out on securing LNG regasification capacity and hence LNG supplies. Siting and approval procedures need to be strengthened.
- Investment in downstream transportation and distribution networks is also deteriorating when compared with the assessment in the *GMR 2006*, particularly in the IEA European region where infrastructure investment essential to cope with new flows of gas caused by increasing import dependence is not being sanctioned in the absence of clarity in the regulation of cross-border infrastructure.
- There is also mounting concern in North America, particularly about impediments to investment in local and regional grids.

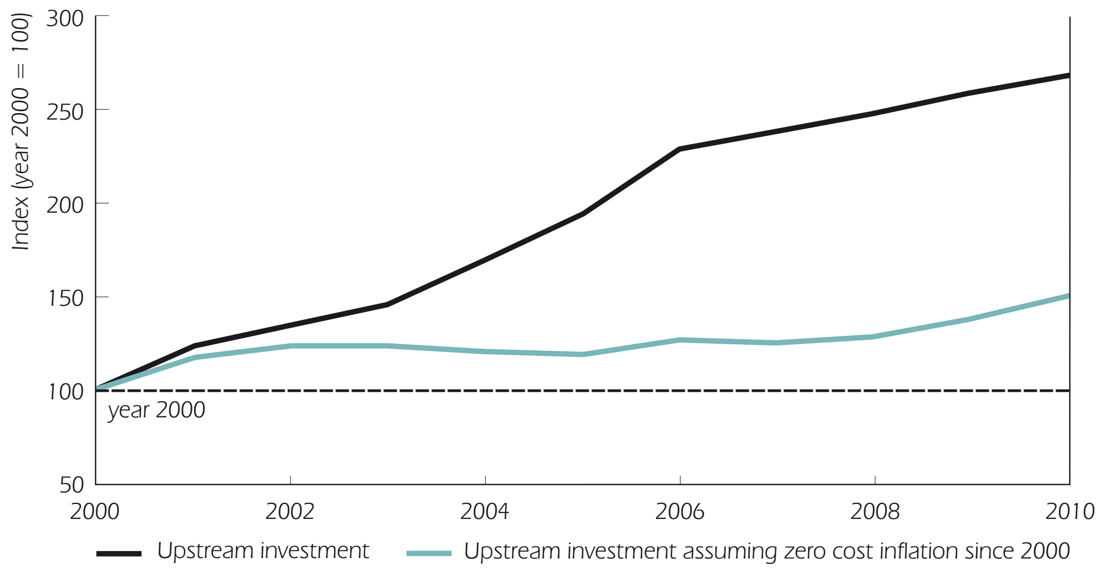
The investment chapter has been written with reference to the IEA's *World Energy Outlook 2006* (*WEO 2006*). We assess current gas sector investment by activity with reference to the *WEO 2006* reference scenario which analyses investment needs in the global energy industry to 2030 assuming no significant change in existing energy policies. In this scenario, investment requirements across the entire global gas industry amount to some USD 156 billion per year.

General cost inflation

All construction costs have increased sharply in recent years. In part, this has resulted from higher basic material costs, such as steel and cement, but cost inflation has also been driven by a sharp increase in demand for equipment and manpower as companies have sought to respond to higher energy prices. A vicious circle has been started whereby the costs of obtaining energy, raw materials and human resources are increasing the cost of incremental supplies of the same basic factors of production.

An increase in the number of large-scale projects being developed at the same time, their remoteness and greater complexity and the increasing need for costly production enhancement at large mature fields have added to the upward

Figure 10 **Upstream oil and gas industry investment in nominal terms and adjusted for cost inflation**



Source: IEA database and analysis.

pressure on cost. This phenomenon has been seen across the oil and gas industry. Figure 10 is taken from *WEO 2006* and shows the increase in actual and planned spending in the oil and gas industry from 2000 to 2010 against the inflation-adjusted spending over the same time period. It shows that in 2010 the industry will be spending around 170% more than in 2000 in nominal terms, but will achieve an inflation-adjusted increase of less than 50%.

Exploration plans themselves will be hampered by the shortages of rigs and manpower over the next one to two years. This is likely to result in a shortage of new projects awaiting development when the current wave of upstream developments is completed early in the next decade. Further, such inflationary pressures will cause delays in ongoing projects which could tighten the balance and make this situation worse.

There are certain factors within the control of project managers which could help reverse this trend as well as simply postponing or cancelling a project, these include:

- Scope and cost review for each element of the project;
- Modular construction approach, rather than lump-sum turn-key contracting;
- Economy of scale by expanding or merging projects;
- Use of identical designs;
- Competitive engineering bidding processes (using different companies).

A 2005 benchmarking survey of 30 oil and gas companies and 115 university studies is cited in *WEO 2006*. It estimates that the demand for petroleum industry personnel will increase by around 7% per year for the next ten years. Demand for experienced, qualified personnel far outstrips current availability and there are regional shortages of petroleum geology and engineering university graduates. The biggest shortages of local graduates are in North America, the Middle East, Russia and other transition economies. Venezuela, Mexico, India, China and Indonesia are among the few countries with excess graduates in petroleum disciplines. Globally the supply should meet demand if all petro-technical graduates were to join the industry. A historically low intake of suitably qualified graduates into the industry is pushing up the average age of the workforce across all disciplines: it currently ranges from 40 to 50 years (Deloitte, 2005). A significant gap also exists between the supply of, and demand for, mid-career experienced industry personnel.

Upstream

For gas projects, the upstream absorbs the majority of total investment, accounting for 56% of total gas sector spending, or USD 87 billion per year. As OECD regions look to import more gas, it is clear that the majority of this investment will have to be committed in non-OECD countries. A particular concern is whether the high rates of increase in exports projected for some regions, especially the Middle East, are achievable in light of institutional, financial and geopolitical factors and constraints. A small number of countries are expected to provide the bulk of the incremental gas to be exported, including as LNG (Russia, Central Asia, Nigeria, Middle East and North Africa). If problems were to arise within these countries or between these countries and importers, it would be less likely that all the required investments in export-related infrastructure would be forthcoming. A large volume of gas is produced from fields which contain both gas and oil.[4] Any deferral of upstream oil investment may therefore have a knock-on effect for gas production.

While most upstream investment continues to go to development of fields already in production, the increase in spending since the start of the current decade has been focused on development of new fields that were already discovered by 2000. Spending on exploration has risen in absolute terms since the beginning of the current decade, but has continued to decline as a share of total upstream investment. Exploration continues to be successful in discovering fields of a diminishing size – many more of which are needed to offset decline at super-giant fields developed last century. On the one hand there is an increasing need for investment in declining gas fields, but on the other hand the new greenfield sites such as Alaskan North Slope or Yamal in Russia are of the order of four to five times more expensive to develop than was existing gas production.

Oil and gas companies based in OECD countries continue to dominate global upstream investment. Although the share of total investment made by national oil companies in the Middle East and

4. "Wet gas fields" are primarily gas fields with associated liquids, fields with large volumes of liquids often contain "associated gas" which can be produced or flared.

transition economies is projected to be higher in the second half of the decade than in the first, it is still remarkably small, at less than 10%. Unit development costs are however significantly lower in the Middle East and onshore Caspian regions than in remote green-field, deep water or arctic regions.

The international oil and gas companies are uniquely equipped to undertake complex, large-scale projects, thanks to their project-management skills, their access to advanced technology and their financial resources. But opportunities for them to invest are in fact receding as a result of government policy, civil conflict or geopolitical risks – especially in the Middle East, Russia, Africa and South America. The willingness and ability of national oil companies to develop reserves are in many cases very uncertain (see separate sections on South America and MENA).

There may be more that OECD governments can do domestically to ease any future tightness in the market. Those OECD countries with gas reserves should examine their domestic production policies and verify that these policies indeed sufficiently encourage the economic production of gas. Governments' attention should be drawn particularly to the experience of the United Kingdom and Norway who have recently modified their upstream policies to maximise the economic output from their reserves and returns to the state. These policy revisions have particularly focussed on encouraging development of so-called "fallow fields" – economic reserves held by companies but not in production (see sections on Norway and United Kingdom).

Investment to 2015

For projects that target first production at the end of 2010-12, final investment decisions must be taken before the end of 2007. Even then, the project must progress very smoothly if it is to hit the 2010 deadline. Final investment decisions (FID) on the investment in gas-supply capacity that will come on stream in the first period have largely been taken and investment capital is feeding into construction. Significant capacity should be available by 2010 to meet the rise in demand, but there are considerable risks of delays and cost overruns. Our analysis suggests that there is little margin for error with mostly downside risk for time and cost.

The *GMR 2006* noted that cost overruns and construction delays were expected to have a substantial impact on upstream project delivery in the current investment cycle. This is now much more of a concern. Although most engineering contracts are signed at fixed rates, service companies do not provide full insurance against raw materials and human resource cost pressures. Inflationary effects will materially increase the industry's required call on upstream capital to 2010-2012 and beyond. The performance of upstream LNG investments in the Table 5 below illustrates this risk of inflation and slippage, showing an average delay of around one year amongst the projects noted and average cost increases of some USD 2.26 billion per project.

Greenfield projects are increasingly complex, and LNG is no exception, with only a few specialist producers able to supply key components. Because of this, cost inflation and delays are likely to be

Table 5 Selected global LNG projects

	Previous expectations	Latest expectations and estimates	Cost and delay
Sakhalin 2 (Russia)	Before July 2005 USD 10 billion Production in 2007	December 2006 USD 22 billion Production in 2008	12 months USD 12 billion
Gorgon (Australia)	December 2005 (When marketing looked good) USD 8 - 9 billion FID 2006, Production in 2010	December 2006 USD 12 billion+ (for upstream and environmental reasons) FID mid 2007, production in 2011	12 Months USD 3 - 4 billion
Pluto (Australia)	FID mid 2007, production in 2010	So far, no apparent problems	
North West Shelf Train 5 (Australia)	June 2005 FID USD 1.5 billion, start 2008	August 2006 Cost 30-35% up, start 2008	USD 0.5 billion
El Andalus (Algeria)	October 2004 USD 1 billion (+2.1 upstream) Production by November 2009	December 2006 USD 3.95 billion (EPC bid) Production probably after mid 2010	8 months USD 0.85 billion
Skikda (Algeria)	June 2005 Production in 2009 or 2010	February 2007 USD 2.7 billion (EPC bid) Production in 2010 or 2011	12 months
NLNG 7 Plus (Nigeria)	March 2006 (buyers short-listed) Production in 1Q 2010	February 2007 (SPAs signed) FID in 2007, Production end 2011	21 months
Brass LNG (Nigeria)	December 2005 (buyers short-listed) USD 4 billion Production in 2010	August 2006 (partners reorganised) USD 7 billion (excluding upstream) due to site issues Production in 2011	12 months USD 3 billion
OKLNG (Nigeria)	February 2006 (project development agreement) USD 6 billion FID in 2006, production in 2010	February 2007 USD 9.8 billion (+ USD 2 billion upstream) FID 1Q 2007, production in 2011	12 Months USD 3-4 billion
Angola LNG (Angola)	September 2005 (integrated marketing strategy) Production in 2010	February 2007 EPC 1Q 2007, production in 2011	12 months USD 3 billion
Snøhvit LNG (Norway)	March 2002 USD 6 billion, production in 2005	March 2007 USD 9 billion, production in 2007	24 months USD 3 billion
Train X (5) (Trinidad)	Mooted in 2005	Domestic industrial sector has taken center stage	
Peru LNG (Peru)	April 2004 Production in 2009	January 2007 (EPC awarded) USD 1.5 billion, production in 2010	12 months

Source: Media reports.

concentrated in bottlenecks. Upstream investment coupled with international pipelines is also at risk of inflation and slippage. However, there tend to be many other related factors also at play in such projects such as environmental concerns, land ownership and border demarcation along the pipeline route. Delays in pipeline projects therefore cannot be explained purely in terms of cost factors (for a discussion of some other factors related to pipeline construction please see below).

The LNG industry is in the middle of a rapid expansion of capacity – a classic "boom". Despite this, no final investment decisions were taken in the whole of 2006 for new LNG supplies and in the first quarter of 2007 there was only one such project sanctioned. Peru LNG was the first new LNG project for 18 months. Meanwhile Qatar, the world's largest exporter and a key driver of current supply growth, is maintaining its moratorium on the super-giant North field, meaning that the world's third largest reserve holder will not invest in new projects until the end of the current investment period, at the earliest. The future growth of the GTL industry also has been called into question as the first quarter of 2007 also saw Exxon Mobil cancel plans for its Palm GTL project (see Recent Developments section).

Concerns over investment beyond 2012 are already surfacing in the industry. While the pipeline industry has continued to provide for the bulk of globally traded gas, LNG has provided the majority of incremental supply that matches global demand growth. Global LNG liquefaction capacity itself will have doubled in size from 2005 to 2010, but if it is to continue this stellar growth then new projects must be sanctioned soon. But is there another Qatar, which became world LNG leader in under a decade? We have augmented the list of key success factors in the case of Qatar, shown by leading industry consultant Andy Flower.[5]

The Qatar advantage

- Enormous (25 Tcm) gas reserves with high liquids content
- Well developed port (Ras Laffan) with space for expansion
- Quick government decision making
- Only 2 partners in RasGas II and III and Qatargas II, III and IV when investment decisions taken
- Stable political climate (credit rating)
- Well co-ordinated commercial and public policy environment
- Good geographic location for LNG

Hence, it is far from certain that all the gas investment needed will occur worldwide. Current high costs of basic factors of production such as raw materials and human capital are slowing the rate of new investment which will will inevitably impact global gas supplies beyond 2010 and perhaps precipitate some degree of deflation in services sector costs. This current trend of service sector expansion and future contraction is symptomatic of the cyclical nature of the industry. Nevertheless, should the paucity of FID continue in the next few years, very serious concerns will arise about the sufficiency of gas sector investment in the period to 2015.

We believe that a good portion of greenfield investment in this period will be a first wave of large scale investment in new basins, such as the Russian Arctic and deep-water Caspian as well as basins already identified for LNG projects such as Nigeria, Australia and Iran. The sensitive investment and environmental climate and/or lack of existing infrastructure will mean higher capital investment per

5. "Andy.Flower@virgin.net

Box 2 ***LNG vs pipeline gas investment***

Whether a gas reserve is to be developed as LNG or connected via pipeline to markets, very large amounts of capital are needed. A "typical" greenfield LNG project is likely to start producing around 10 to 12 years after initial development plans are drawn up. Brownfield expansions can however take place in as little as 5 to 7 years. Commercial LNG projects also benefit from a certain amount of flexibility. Approximately 30% of new LNG project investments are regarded as "price sensitive", meaning that if market conditions in the intended destination are not suitable, the owner can market the gas somewhere else. Although it is difficult to put a price on a "standard" new LNG value chain, we estimate that a company approaching a new greenfield site would budget in the order of USD 3 - 5 billion for liquefaction, USD 2 billion for shipping and a further USD 0.8 - 1 billion per terminal for regasification.

By contrast, major international pipeline projects often have to cross multiple frontiers, and can take any length of time upwards of ten years. Pipeline investments tie reserves and markets together for long periods of time. Pipeline investors therefore need large deep and liquid markets to ensure that they will be able to place large volumes of gas at a satisfactory long-term average price. Pipeline costs themselves have increased rapidly with the price of steel, perhaps resulting in a cost of between USD 1 - 2 billion per 1 000 km of large diameter pipeline depending on the terrain and conditions. Transit issues, legal and regulatory hurdles ensure that investment cost is joined by many other critical business factors in order to ensure investments in new gas pipelines are made. In some markets, investors seek financial exposure to the oil market rather than relying on gas fundamentals – either way, long-term contracts are necessary to obtain financing for such deals.

As with any investment, the commitment of large volumes of capital to gas supply requires management of commercial risks and mitigation/minimisation of non-commercial risks. The regulatory, institutional and political barriers to new pipeline investment can be formidable, while these are much smaller in the case of LNG. We believe that this is a principal reason why the number of proposed LNG projects continues to grow more rapidly than the number of long-distance pipeline projects.

unit production capacity in these regions. Technological advances will play an important role in accessing reserves in an environmentally sensitive manner. But new technology is almost always accompanied by initial growing pains.

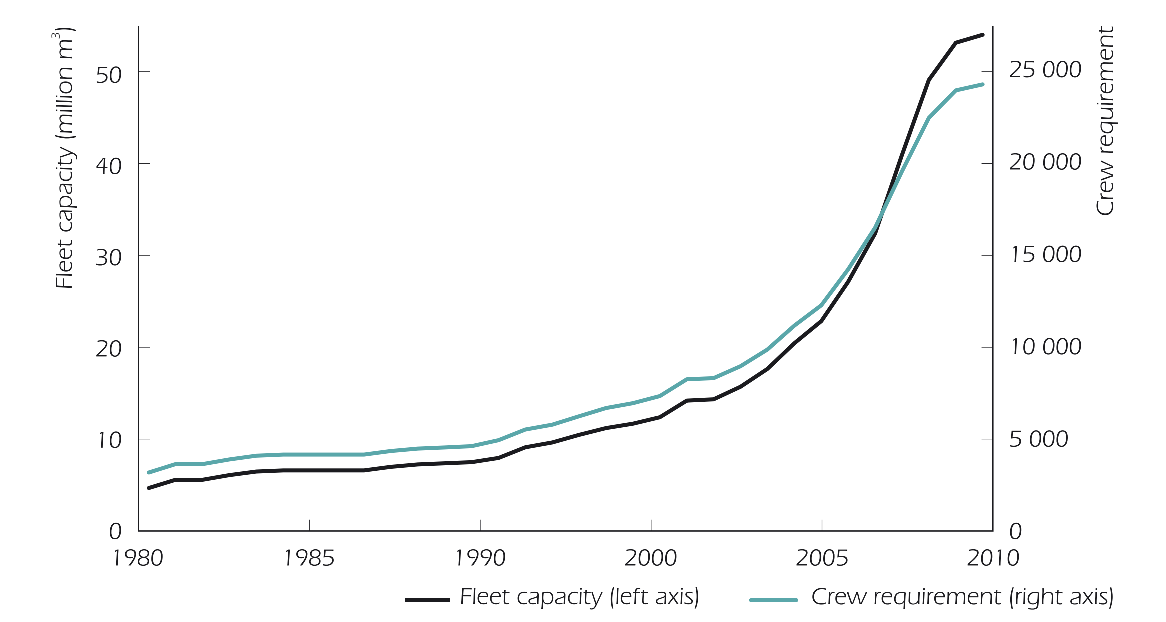
The period to 2015 will also see the maturing of the current wave of coal-bed methane, tight sands and tight shales gas plays. These production zones tend to require more investment than traditional gas fields in order to maintain production and manage declines. It will be important to closely watch the production profile of these fields as they mature and it may be necessary to revise investment requirements accordingly.

Shipping

For LNG shipping, we look at two critical factors, the physical capacity of the fleet and the availability of crews. The number of ships is increasing rapidly even as the average volume of ships is also increasing. A record 35 ships are scheduled to be delivered in 2007, adding to the current 220 carriers. Another 47 ships are expected in 2008. The global fleet will number approximately 350 vessels by 2010 and is widely expected to approach 400 by 2015. The average capacity of a new ship will grow from 140 000 m^3 in 2005 to 180 000 m^3 in 2008. We believe that physical shipping capacity is therefore unlikely to be a bottleneck in the gas industry to 2015. Investment into shipping is running ahead of requirements through to 2015, but this additional flexibility will be necessary for increased short-term optimisation in the LNG industry.

On the other hand, the availability of trained crews is a much greater concern, although information on recruitment and training is much more difficult to obtain. On one side, we are confident that companies making an investment of some USD 200 - 300 million in each ship will plan crew availability. On the other hand, the sheer scale of the human resource challenge seems daunting. Between now and 2010, there is a need to train some 9 000 seafarers, including nearly 3 000 qualified officers (see LNG Section for a fuller discussion).

Figure 11 ***LNG shipping fleet capacity and crew requirement***



Source: IEA data.

Transmission pipelines

We are particularly concerned by what we believe to be considerable underinvestment in transmission pipelines for the period to 2015. Despite the continuing preference for investment in LNG as a means of moving large volumes of gas over large distances, there are some regions where pipelines are essential for geographical reasons. Clearly in a globalising market, global pipeline and LNG trade are complementary in meeting global gas demand. With increasing investment in pipeline gas, there will be less pressure on the global LNG market. Conversely, if pipeline investment continues to lag requirements (as appears to be the case), the LNG market will remain tight.

For illustration, we have mentioned a few of the more substantial pipeline projects planned to deliver gas to OECD markets. Since all IEA regions will increasingly participate in the global LNG market, these pipeline projects give an idea of the investment balance.

In order to market Caspian gas in Europe, Russia or China, large scale pipeline investments will need to be made. China has recently announced an expansion of its internal West-East pipeline, while Gazprom is negotiating a framework in order to expand the capacity of its central Asian pipeline system to Europe. The USD 5 - 7 billion European Nabucco project targets the same basin with the promise of brining 30 bcm per year of gas to a premium market, but such an investment will need substantial political backing if it is to be realised in the 2015 timeframe. Apart from this, the investors will have take into account the regulations of each of the 5 countries lying along the path from Turkey to Austria. Meanwhile, if Chinese investment in Caspian region gas results in piped gas to China, the Chinese call on future LNG supplies may be lower. This would free more LNG for the Atlantic. If more pipeline gas investments are directed at the Eurasian market, then European LNG demand is likely to be lower to 2015, having the reverse effect.

Both Russian greenfield basins, Yamal and Shtokman, are (somewhat optimistically) slated for first gas in 2011. These developments are for delivery by pipeline to domestic and European markets, though an LNG option for Shtokman has not been ruled out. These pipeline projects present significant technical challenges, particularly those linking the Yamal fields with the existing pipeline networks from Western Siberia. Planned flows from Yamal approach 140 - 180 bcm per year. Investment costs are correspondingly high, with estimates approaching some USD 15 - 20 billion just for the pipeline link to the existing network. Gazprom experts have been studying the permafrost in the Yamal region for several decades with a view to this development; while they should be uniquely placed to make this investment, it will nevertheless represent a substantial call on capital.

The 50 bcm per year North Slope and 20 bcm per year MacKenzie Valley pipelines are planned to deliver North American gas to market around 2015 or later costing some USD 25 billion and USD 15 billion respectively. With the increasing flexibility of Atlantic basin LNG, we see considerable competition between these projects and the major pipelines above which will furnish European demand. Any North American gas surplus or deficit is likely to be made whole by increased movement of LNG away from or to United States receiving terminals. In this sense, it will be important to see whether Yamal, Shtokman and North-Slope pipeline investments are made in the same time period, in which case the Atlantic LNG investment could be delivered to the Pacific.

There is much talk of piping Eastern Russian gas reserves to markets in Japan, Korea and China before 2015. (Sakhalin LNG will move to Pacific markets next year). The plans of Russian producers in the relevant regions suggest that it is unlikely that investment in production and transport from greenfield sites will be made to deliver gas to Pacific markets before 2015. However, if investment plans were given sufficiently high priority, it is possible that gas could be flowing eastwards from Kovytka or East Siberia before that time. Any pipeline gas into the Pacific markets would reduce the call on Pacific LNG, which we would then expect to see traded into the Atlantic market.

Downstream

The amount of investment in downstream gas infrastructure in consuming countries – including transmission pipelines, storage facilities and distribution networks – will by shaped by the effectiveness of the regulatory framework in channelling private sector finance. The recent trend in private equity financing demonstrates that there is a large amount of money available if the conditions are right. While there are some problems in regulatory approaches in IEA North America, it is most clearly in IEA Europe that infrastructure investment is being impeded. While policy makers must be mindful of the effects of environmental policies and not-in-my-backyard (NIMBY) resistance, it is too easy to blame these factors alone for the underinvestment in downstream pipelines in Europe, though they clearly do contribute.

Two general themes of this book are that OECD regions are becoming increasingly import dependent and that downstream gas industries are also becoming increasingly market-based. The twin effects of a structural shift in supply and a change in the investment environment create substantial challenges for downstream investment. Regulators must focus on facilitating new infrastructure additions in a market based manner in order to handle increased imports from different sources. In most cases the market is best placed to decide what infrastructure is needed; regulations should ensure that such investments are made in a way that enables infrastructure to be made available to all market participants. Regulators and governments need to have a role in managing increased import dependence and must have a more sophisticated role than simply decreasing the costs of using existing infrastructure.

Pipeline regulation is new to many European countries, where downstream infrastructure should now be regarded as a natural monopoly and separated from the competitive business of gas supply. In this environment of change, there are serious problems with commercial incentives to invest in new infrastructure, largely the fault of regulation designed solely to perform other functions, namely increasing competition and reducing costs. The end result is that within many European countries, infrastructure investment essential to cope with new flows of gas is not being sanctioned.

Within Europe, but across several countries, there is an even greater problem, which is that there is no harmonisation of regulatory structures within the region, nor a European regulatory body. This means that a project to build a gas pipeline between two countries might be profitable on one side of the border but not on the other. Even if it were profitable at all, such a pipeline faces formidable obstacles to be built in the current environment because of a lack of timely regulatory decisions. Pipeline projects which must cross several European countries face considerable regulatory risk and uncertainty if they are to proceed.

In particular, investments such as Nabucco, a USD 5 - 7 billion import project which travels though five different IEA European countries, will not be realised unless a broader view of regulation is adopted. For such a pipeline, various factors must be individually negotiated, including the rate of return, third-party-access regime, approvals process, length of time to approval and the roles of the national and EC authorities. This pipeline would be extremely important for European supply security as it would open a new "corridor" and supply source from the Caspian. Nevertheless, large scale international projects such as Nabucco perhaps give the clearest example of the way in which Europe is threatening its own future supplies of gas through regulatory uncertainty.

Because of these twin deficiencies in regulation effects, a serious lack of investment in Europe can be seen. This comes at a time when investment is desperately needed to allow the market to cope with the structural shift towards greater import dependence and greater competition. European regulators individually must see it as their mission to promote investment as well as efficiency and competition.

Storage

Commercial storage

The rate of investment in storage has slowed considerably in IEA Europe, but increased in IEA North America in recent years. LNG storage in the Pacific region is keeping pace with trends. Storage in Europe is lagging investment requirements substantially by some USD 1 - 2 billion per year although investment in the United Kingdom is against this trend, notwithstanding some planning problems. Another country which is developing large amounts of new storage is Germany, where many projects were started under the old vertically-integrated market and are still progressing. The general trend of underinvestment in Europe is very worrying for consumers because the volume of gas imports to Europe is increasing, as are the distances over which it must travel. More disturbingly, domestic production, and the flexibility that it guarantees, is decreasing fast. These are all good commercial arguments to build more storage, but because of market design, the investment signals are obscured from potential investors.

In order to encourage competition, some incumbent companies who used to build storage under the old integrated business model are now impeded from investing under the same terms. This is positive for competition, but negative for investment. In a properly competitive Europe-wide market, current demand and supply trends would result in a strong business case for storage developers. However, the lack of gas-on-gas competition in most European markets means that wholesale price seasonality (or volatility) is not present, so the case for independent storage investors is weak. They therefore look to regulators to provide a model whereby their investment is guaranteed a fixed return which reflects the risks of storage development.

The comparative lack of storage projects elsewhere in IEA Europe seems to be largely caused by national gas markets being stuck "in limbo" between unliberalised and liberalised market design. This means that market actors are not yet sufficiently separated or sufficiently specialised to make decisions from the "bottom up", as in the United Kingdom, nor can they see the fundamentals of the whole value chain from the "top down" perspective of a vertically integrated company as was the case in Germany (until recently). Holding companies owning storage arms receive conflicting incentives across their wide business interests.

In the absence of price signals to act as the glue holding the value chain together, many European players look to regulation as the "sticking plaster" until a competitive market structure is established. However there are few supportive regulatory regimes for building storage in Europe as storage is not subject to regulated third party access under the second gas directive. As with pipeline investment in Europe, regulatory institutions seem focussed on liberalisation as a process, to the detriment of investment outcomes.

The aggressive expansion of investments in North American storage capacity bears testament to the ability of players in liberalised gas markets to make storage investments. An increase in storage investment in the world's most liquid market will allow North America to increasingly provide storage services to the global LNG market. In a globalising market, Japan and Korea will benefit from this investment trend as they have few domestic storage options and have large demand for flexibility services to augment their long-term LNG contracts.

REGIONAL DEMAND & SUPPLY BALANCE TO 2015

This chapter provides an overview of regional demand and supply balance to 2015, based on the Reference Scenario of the IEA *World Energy Outlook 2006* (*WEO 2006*), which projects energy balances over the period until 2030.

Demand

Primary gas consumption is projected to increase in all regions over the period 2004 - 2015 in the *WEO 2006* Reference Scenario, from 2.8 trillion cubic meters (tcm) in 2004 to 3.6 tcm in 2015. Globally, demand grows by an annual average of 2.5% per year. The biggest increases in volume terms occur in the Middle East and Developing Asia furnished largely by domestic and pipeline gas sources. Demand rises at the fastest rates in Africa, the Middle East, and developing Asia, notably in China and India. The shares of gas in China and India are expected to grow relatively rapidly, but will remain small, from 3% and 4% in 2004 to 4% and 5% in 2015, respectively.

The share of gas in the global primary energy mix stays at the same level in 2015 as in 2004 at 21%. The IEA's gas-demand projections in most regions have been scaled down over the last year, mainly because underlying gas-price assumptions have been raised, creating an incentive to use more coal in power generation. Nevertheless, there is considerable

Table 6 **World primary natural gas demand in the reference scenario (bcm)**

	1990	2004	2010	2015	2004 - 2015*
OECD	1 028	1 453	1 593	1 731	1.6%
North America	623	772	830	897	1.4%
Europe	321	534	592	645	1.7%
Pacific	84	148	171	188	2.2%
Transition Economies	767	651	720	770	1.5%
Developing countries	280	680	932	1 143	4.8%
Developing Asia	88	245	337	411	4.8%
China	17	47	69	96	**6.7%**
India	12	31	43	53	**5.0%**
Middle East	96	244	321	411	**4.9%**
Africa	36	76	117	140	**5.7%**
Latin America	60	115	157	180	4.2%
World	2 075	2 784	3 245	3 643	2.5%

*Average annual growth rate.
Source: *World Energy Outlook 2006*, IEA.

Table 7 World final gas consumption (bcm)

	1990	2004	2015	2004 - 2015*
OECD	714	902	1,018	1.1%
Transition economies	370	274	336	1.9%
Developing countries	130	296	477	4.4%
World	1,213	1,473	1,831	2.0%
Industry	666	681	875	2.3%
Residential, services and agriculture	510	708	856	1.7%

*Average annual growth rate.
Source: *World Energy Outlook 2006*, IEA.

potential upside to gas demand if coal plants do not progress past the planning phase (for a discussion please see separate "Gas for Power" section).

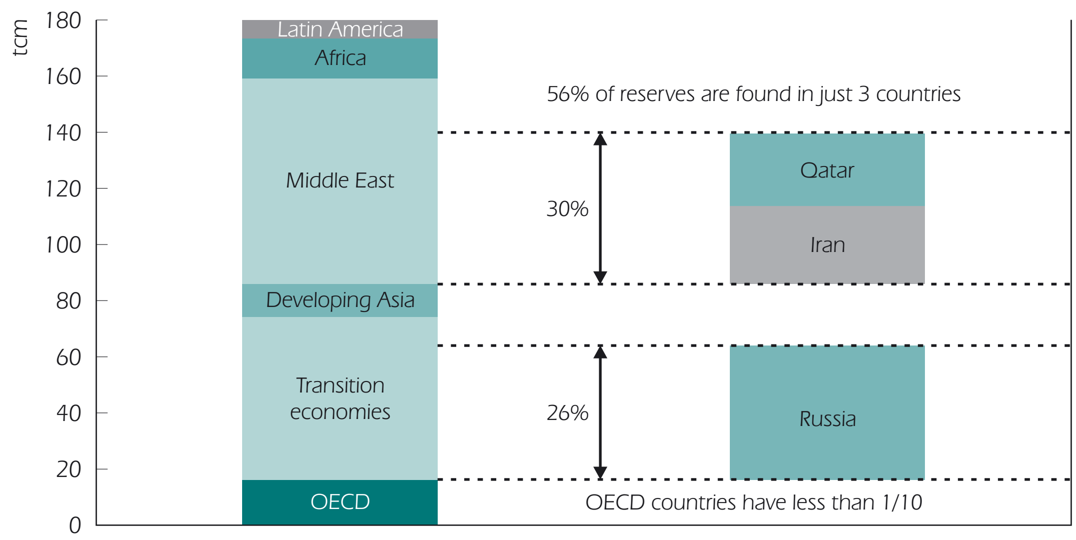
The use of gas in the power sector increases by 3.1% per year from 2004 to 2015. In absolute terms, gas demand in the power sector increases most in the Middle East, where it is the main alternative to premium priced oil as a fuel. Final gas consumption grows markedly less rapidly than primary gas use – by 2.3% a year in industry and 1.7% in the more mature residential, services and agricultural sectors. Final consumption slows in the OECD because of saturation effects, sluggish output in the heavy manufacturing sector and modest increases in population. Demand grows more strongly in developing countries and transition economies along with rising industrial output and commercial activity. Residential gas use nonetheless remains modest compared with OECD countries, because incomes are often too low to justify the investment in distribution infrastructure. End-use efficiency gains in the transition economies also temper the growth in residential gas demand. Some oil-producing developing countries continue to encourage switching to gas in order to free up more oil for export. Both these latter factors are discussed later in sections on Russian and MENA.

Supply

Resources and reserves

Gas resources are more than sufficient to meet projected increases in demand to 2030. Proven reserves amounted to 180 trillion cubic metres (tcm) at the end of 2005, equal to 64 years of supply at current rates (Cedigaz, 2006). Were production to grow at the 2% annual rate (2.5% in 2004-2015 and 1.7% in 2015-2030), reserves would last about 40 years. Close to 56% of these reserves are found in just three countries: Russia, Iran and Qatar. Gas reserves in OECD countries represent less than a tenth of the world total. Nevertheless, worldwide proven gas reserves have grown by more than 80% over the past two decades, with large additions being recorded in Russia, Central Asia, and the Middle East.

Figure 12 **World reserves of natural gas (as of January 2006)**



Data source: Cedigaz.

Much of the world's gas reserves have been discovered while exploring for oil. In recent years, the larger share of reserve additions has come from upward revisions to reserves in fields that have already been discovered and are undergoing appraisal or development. As with oil, the gas fields that have been discovered since the start of the current decade are smaller on average than those found previously.

In sum, recoverable gas resources including proven reserves, reserve growth and undiscovered resources, are considerably higher than reserves alone. According to the United States' Geological Survey, they could total 314 tcm in a mean probability case (The United States' Geological Survey, 2000), some 75% higher than proven reserves. Cumulative production to date amounts to only around 15% of total resources.

Production

Projected trends in regional gas production in the *WEO 2006* Reference Scenario generally reflect the relative size of reserves and their proximity to the main markets. Production grows most in volume terms in the Middle East and Africa. Most of the incremental output in these two regions will be exported as LNG, mainly to Europe and North America. Production is expected to grow less rapidly in Russia, despite the region's large reserves; much of that gas will be technically difficult to extract and transport to market. There are also doubts about how much investment will be directed to developing reserves in the transition economies. Developing Asia sees slower growth, as Indonesia struggles to develop its reserves for export to other countries in the region. Europe is the only region which experiences an absolute drop in output

Table 8 World natural gas production in the Reference Scenario (bcm)

	1990	2004	2015	2004 - 2015*
OECD	879	1128	1205	0.6%
North America	641	756	820	0.7%
Europe	211	328	312	-0.5%
Pacific	27	44	72	4.6%
Transition economies	841	802	964	1.7%
Developing countries	362	874	1517	5.1%
Developing Asia	131	304	422	3.0%
China	17	47	69	3.6%
India	12	28	43	4.0%
Middle East	100	283	600	**7.1%**
Africa	69	158	277	**5.2%**
Latin America	62	129	217	**4.8%**
World	2082	2804	3686	2.5%

*Average annual growth rate.
Source: *World Energy Outlook 2006*; IEA, *Natural Gas Information 2006*, IEA.

between now and the end of the projection period, as North Sea production peaks early in the next decade and gradually declines thereafter. In aggregate, annual world production expands by almost 0.9 tcm, or 31%, between 2004 and 2015.

Most natural gas supplies will continue to come from conventional resources. The share of associated gas is expected to fall progressively as more non-associated fields are developed to meet rising demand, despite a further reduction in amount of associated gas flared. Several countries, especially in the Middle East and Africa, are implementing programmes to reduce gas flaring. Around 150 bcm of gas is flared each year, mostly in the Middle East, Nigeria and Russia (*Optimising Russian Natural Gas: Reform and Climate Change*, IEA 2006; *Towards a World Free of Flares*, World Bank, 2006).

Non-conventional gas production, including coal-bed methane (CBM) and gas extracted from low permeability sandstone (tight sands) and shale formations (gas shales), increases significantly in North America. The United States is already the biggest producer of non-conventional gas, mainly tight sands gas and CBM from Rocky Mountains. Together, they currently amount for about 10% of total United States' gas demand. In most other regions, information on the size of non-conventional gas resources is sketchy. In some cases, there is no incentive to appraise these resources, as conventional gas resources are large.

In general, the share of transportation in total supply costs is likely to rise as reserves located closest to markets are depleted and supply chains lengthen. Pipelines will remain the principal means of transporting gas in North America, Europe and Latin America. LNG is set to play an increasingly important role in gas transportation worldwide over the projection period, mainly to supply Asia-Pacific and Atlantic Basin markets but increasingly as the glue which binds regional markets together.

Inter-regional Trade

The geographical mismatch between resource endowment and demand means that the main gas-consuming regions become increasingly dependent on imports. In volume terms, the biggest increase in imports is projected to occur in OECD Europe. Imports in that region increase by 120 bcm between 2004 and 2015, reaching 333 bcm – more than half of inland consumption. North America, which is largely self-sufficient in gas at present also emerges as a major importer. By 2015, imports to North America – all of which are in the form of LNG – meet 9% of its total gas needs. Chinese gas imports also grow from around 1 bcm in 2004 to 27 bcm by 2015. The country's first LNG terminal, with a capacity of 6 bcm per year (3.7 mtpa) was commissioned in 2006. Nonetheless, gas still meets only 4% of Chinese energy needs by 2015, marginally up from 3% today.

The Middle East and Africa account for the majority of the increase in global exports between 2004 and 2015. The bulk of the exports from these two regions go to Europe and the United States. Africa contends with the transition economies, including Russia, for the top spot of the largest regional supplier to Europe. In light of current investment plans, there are doubts about whether Russia will be able to raise production fast enough to maintain current export levels to European markets given rising domestic needs and potential sales eastwards. China currently obtains gas supply from Australia and is expecting to take deliveries soon from Indonesia. After 2012, possibly Russia and Central Asia may supply gas to China. Russia is also expected to begin exporting gas to OECD Pacific by 2008 from Sakhalin.

Pipeline gas continues to be traded on a largely regional basis, as there are few large physical connections between the main regional markets of North America, Europe/Russia, Asia-Pacific, Middle East and Latin America. Despite the lack of physical interconnection, these markets are already beginning to integrate as trade in LNG expands. In this way LNG can be seen as a virtual interconnection between regional markets. Increasing LNG trade will expand integration, leading to a degree of convergence of regional prices. LNG accounts for almost 70% of the increase in inter-regional trade since 2004. Inter-regional exports of LNG grow from 90 bcm in 2004 to 150 bcm in 2010 and 200 bcm in 2015. Total liquefaction capacity worldwide is expected to grow from 242 bcm per year in 2005 to 600 bcm in 2015 if all the projects under development are completed on time (though some will undoubtedly be delayed or cancelled – see separate section on Investment).

North America is expected to see the biggest increase in LNG imports over the period between 2004 and 2015. All the

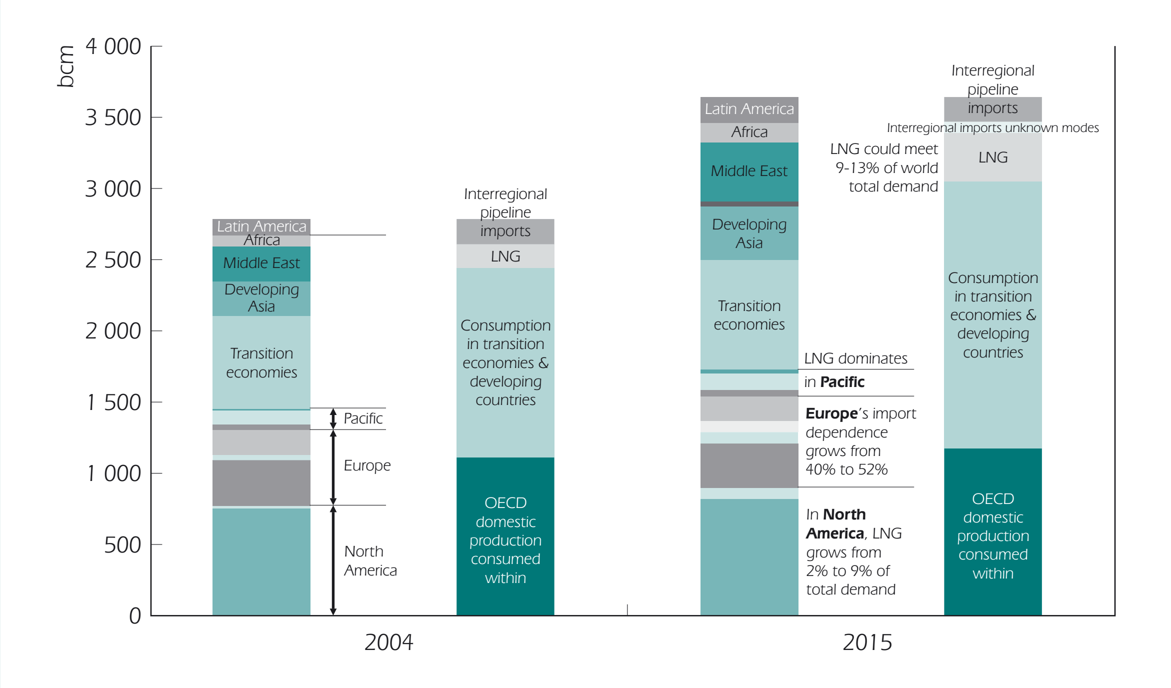
LNG destined for the United States market is likely to respond to short term price trends rather than be fixed volumes on long term contracts. This will mean that North America makes a large entrance on, and contribution to, the globalising gas market.

Taking a more conservative view of LNG development, output by 2015 could be "only" some 440 bcm, still a massive growth. Of this, 80 bcm is likely to go to OECD North America, 160 bcm to OECD Pacific and Chinese Taipei, some 40 bcm to China, India, and Thailand and the remaining 160 bcm to Europe. LNG imports to Europe will interact with pipeline gas sold on oil and hub prices. LNG imports to North America will interact with pipeline gas based on spot markets, and LNG to the Pacific market is likely to be based on a combination of oil indexed and hub prices. The interaction between global and regional LNG and pipeline flows is globalising the markets.

Supply and demand summary to 2015

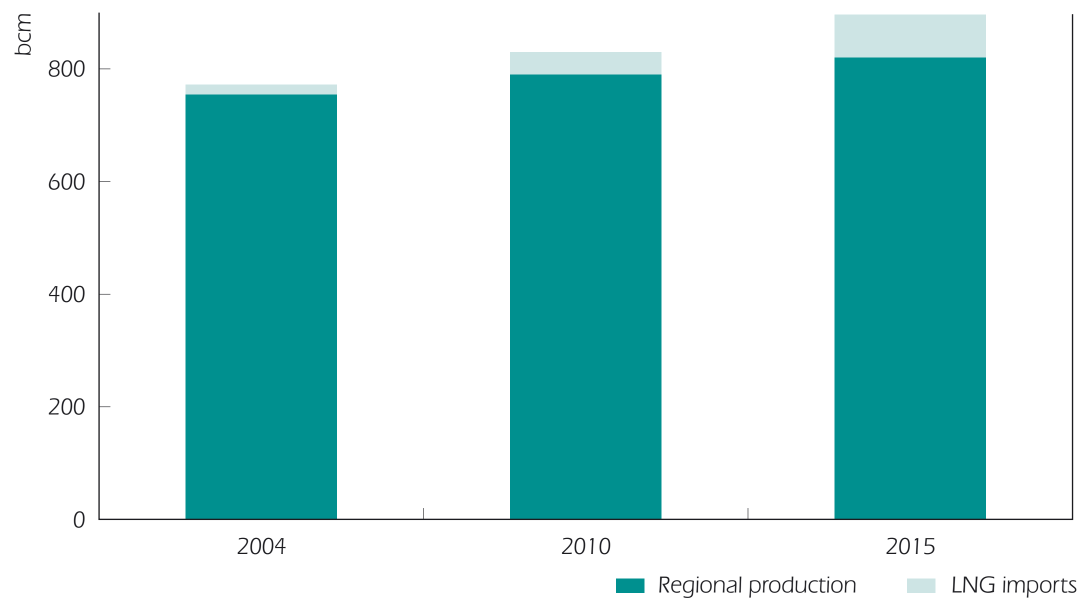
OECD regions will increase their dependence on interregional imports of gas from 23% to 30% (from 328 bcm to 526 bcm). Dependence on LNG will grow from 11% to between 17% and 22% (from 164 bcm to between 302 - 382 bcm).

Figure 13 **Summary of inter-regional natural gas trade in the Reference Scenario**



Source: *World Energy Outlook 2006*, IEA; *Natural Gas Information 2006*, IEA.

Figure 14 **OECD North America gas outlook**



Source: *World Energy Outlook 2006*, IEA; *Natural Gas Information 2006*, IEA.

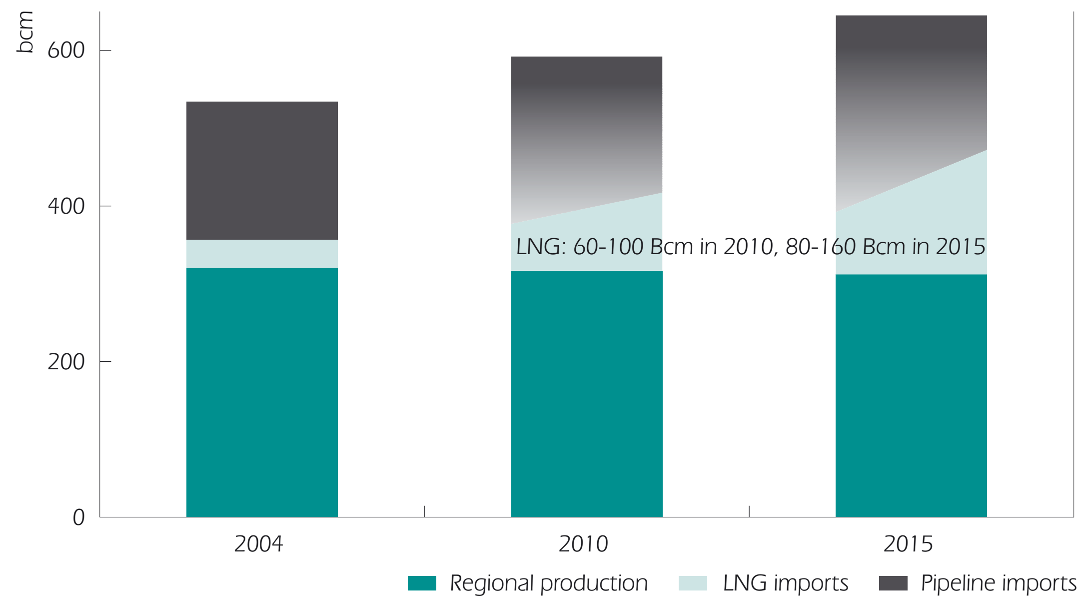
Assuming a modest increase in the United States gas production over the period, as predicted by the United States and Canadian government agencies, OECD North America's depen-dence on interregional imports (in the form of LNG) will grow from 2% to 9% (from 18 bcm to 77 bcm). Should North American gas production not increase to the extent projected, obviously demand on LNG markets will tend to increase.

OECD Europe's dependence on interre-gional imports will grow from 40% to 52% (from 214 bcm to 333 bcm). Its dependence on imported LNG will grow from 7% to between 12% and 24% (from 37 bcm to 80 - 160 bcm). OECD Europe will however see its import demand satisfied by both LNG and pipeline gas, so the growth in LNG imports themselves depends not only on LNG production developments, but also upstream investment in traditional pipeline suppliers and demand growth elsewhere (such as China).

The OECD Pacific region dependence on LNG (both interregional and intraregional imported) will grow from 74% to 77% (from 109 bcm to 145 bcm) as demand growth in Japan and Korea outstrips growth in the domestic pipeline markets of Australia and New Zealand.

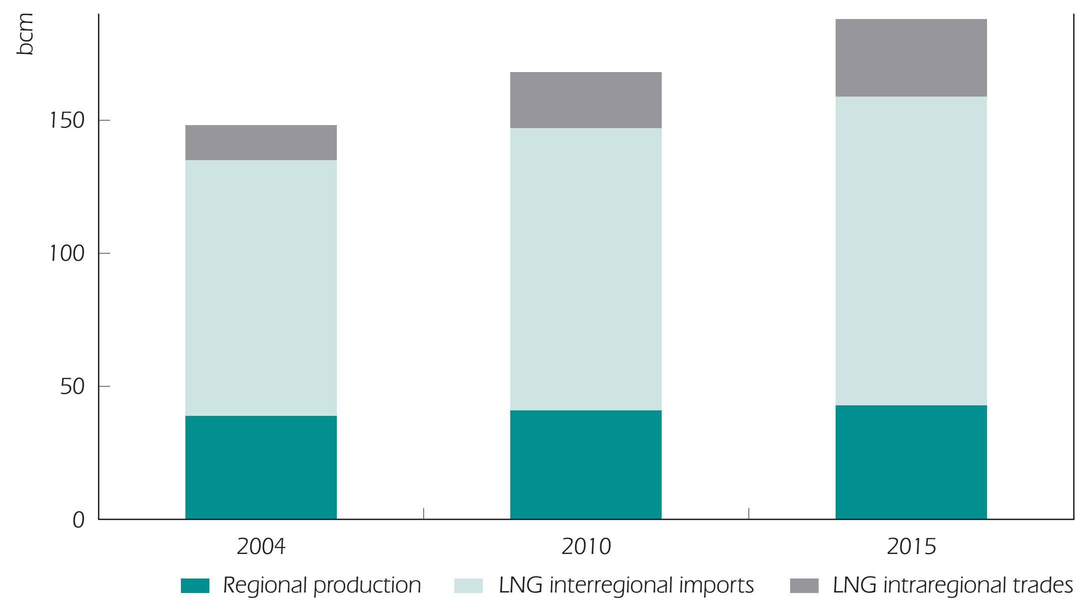
As a result of the massive investment already sanctioned in global LNG supplies, the dependence of global gas demand on LNG will grow from 6% in 2004 to between 10% and 12% by 2015. In the context of a global gas market expanding at some 2.5% per annum, LNG is expanding very quickly.

Figure 15 **OECD Europe gas outlook**



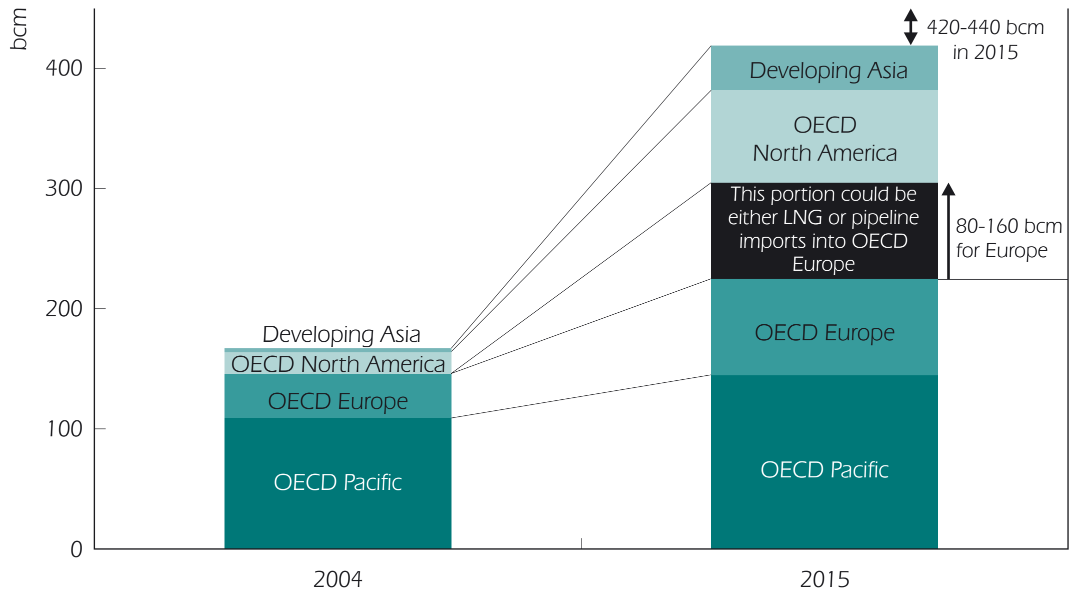
Source: *World Energy Outlook 2006*, IEA; *Natural Gas Information 2006*, IEA.

Figure 16 **OECD Pacific gas outlook**



Source: *World Energy Outlook 2006*, IEA; *Natural Gas Information 2006*, IEA.

Figure 17 **Possible LNG sales by region: one scenario**



Note: Possible LNG imports into Latin America are not included.
Source: *World Energy Outlook 2006*, IEA, *Natural Gas Information 2006*, IEA.

GAS SECURITY

Recent supply disruptions in IEA countries

Recent supply interruptions in a number of IEA regions, plus growing reliance on imports over longer distances, are rekindling a debate on energy security, including available responses to short-term, or even medium term disruptions. Sharp or sustained increases in demand can produce similar effects to reduction of supplies. Such increases in demand can not only be driven by extreme cold weather which leads to a rise in gas demand for space heating, but also extreme hot weather leading to a rapid rise in gas-fired power demand to run air conditioners.

In the absence of additional supply to a region (either through unused production or import capacity–including LNG), the principal response to a supply disruption is to temporarily decrease gas demand. In competitive markets demand reduction happens automatically as gas prices increase, whereas in non-competitive markets demand must be reduced through administrative means. In the examples outlined below, countries or regions suffered supply shortages from a variety of factors, and managed them in different ways.

IEA North America

The IEA North American gas market is fully integrated across both IEA member countries – the United States and Canada. This means that gas moves across the region towards areas of higher price. Price signals are determined by the supply and demand of gas at any given time, so any predicted or existing structural bottleneck is usually resolved over the medium term by new investment in pipeline capacity. Because of this, the North American market has a well interconnected, web-like structure. Prices and price expectations at hubs on the transportation web are the signal used by suppliers and consumers to determine their actions. For example, as price decreases at a hub, so producers scale back production and consumers increase consumption. As prices of gas decrease, consumers burn gas in boilers instead of oil and decrease coal-fired generation in favour of power generation from gas. Price differentials between hubs can signal the need for more interconnection.

Gas can be freely traded between the hubs on the gas pipeline network, so the effects of the hurricanes in the Gulf of Mexico late in 2005 were spread throughout the North American gas market. The loss of 147 mcm per day gas supply (equivalent to 10% of North American consumption) would have been devastating to the affected region were it not for this sharing effect, for example it would have lead to a loss of 62% of gas supply to Texas if confined to just that market.

However, prices did rise substantially, initially to around USD 14 and then USD 15/MBtu, about double previous prices. The principal response to a supply disruption in the North American market was demand reduction by users. Industrial demand in the United States after the hurricanes of 2005 was lower by approximately 68 mcm per day compared to the previous year, due to these high prices, notably in the chemical sector. Residential consumption also decreased, but this is more difficult to attribute to the effects of higher prices rather than temperatures, because domestic gas use tends to rise and fall strongly with the ambient temperature. Also price lags in this sector can often be substantial, so immediate effects are muted.

While the United States market did not manage to attract extra supply in the form of LNG cargoes, the effects of the supply disruption were felt by most LNG importing countries. The price of gas in the North American market became the "price to beat" for any company worldwide to import spot LNG cargoes. Thus, Japanese, Korean and Spanish buyers tended to pay higher gas prices for LNG imports in order to out-bid the North American market.

IEA Pacific

Japan and Korea receive almost all their gas, as they do oil, by tanker. Japan has substantial import capacity at 26 LNG terminals (230 bcm per year), and Korea has 4 terminals (77.4 bcm per year). This capacity offers great flexibility in the case of an upstream gas supply disruption because it is over double total demand (Japan, 85 bcm per year and Korea 30 bcm per year, 2005). Emergency plans exist in both of these countries in the case of an import problem in order to share remaining supply between different demand centres. The emergency plans of both countries include large scale fuel-switching by power generation companies to save gas and use more oil. This would ensure a basic level of gas imports to each of the regional gas markets, although the effect on the global oil markets could be significant.

Japan lacks a national pipeline network which would interconnect its consuming areas such as exists in Korea (although Korea is admittedly smaller). The possibility of a significant disruption at one LNG terminal in Japan therefore poses potential supply security issues for the area served by that terminal. While most Japanese consuming regions have access to more than one LNG terminal, some do not (*e.g.* Niigata, Kagoshima). In such a situation, the affected Japanese consuming area may make use of an emergency plan to ration the use of gas locally, particularly drawing on power companies to switch from using gas to oil. In emergencies, some of the smaller gas companies can manufacture gas from naptha or LPG, while the larger companies consider that they have access to well diversified LNG terminals.

In recent years, long-term supply from Indonesia, previously the world's biggest LNG producer and the major Japanese supplier, has fallen below annual contract levels by at least 10%. These supplies have been successfully replaced by supplies obtained from the growing LNG spot market. This in turn has been made possible by mild weather in other IEA markets, which has freed up LNG from the Atlantic Basin for delivery to Pacific markets.

In Australia, disruptions at gas processing facilities have impacted on gas supplies. In 1998, an explosion at the Longford gas facility caused rolling gas supply interruptions affecting approximately 1.3 million households and 89 000 businesses across Victoria, parts of South Australia and New South Wales over a two-week period. The economic impact of gas supply rationing was significant. Over 150 000 workers were stood down during the crisis and resulted in an estimated cost to Victoria of USD 1 billion (or 1% of Gross State Product). Export earnings were cut by USD 150 million.

On 1 January 2004, a gas leak and fire shut down production at the Moomba gas plant, in northern South Australia. Production at the plant was returned to full capacity by 14 February 2004. In this case, new interconnections for both gas and electricity were available between

South Australia and the state of Victoria, and supplies of both power and gas were maintained throughout the Moomba plant outage without rationing. This highlights the importance of interconnection for smaller consuming regions, and also the potential role of electricity and grid interconnection in gas security.

IEA Europe

IEA Europe is in the middle of a transition to a North-American-style competitive market, with the most advanced countries located in North West Europe (NWE - United Kingdom, Belgium and the Netherlands) and the Iberian Peninsula (Spain and Portugal). The bulk of continental Europe remains dominated by long-term take-or-pay contracts, with prices adjusted periodically, linked to oil. Hence any price response to shortages is at best muted, or even non existent. The weak (or in some cases non-existent) interconnection between European countries means that they have been affected more severely by gas supply shortages than would have been the case in a strongly connected market such as North America,

An example of such a shortage was seen in Italy over the winter of 2005 and 2006, where a combination of cold weather and higher use of gas-fired power led to a daily shortfall of up to 10% of demand, or around 40 mcm per day. In the context of total European gas demand some 50 times larger than this shortfall, this was relatively small, but the weak interconnectivity and poor market flexibility (for example gas prices cannot respond to higher demand from the power sector) meant Italy suffered gas shortages which had to be met by emergency measures. These included fuel switching and plant closures by administrative decree, temporary relaxation of environmental standards to allow fuel oil to be burnt, and gas rationing.

Over the same winter 2005/06, the United Kingdom encountered supply shortages, as cold weather coincided with an unexpectedly rapid fall in domestic production. Late in the winter, a fire at the country's major gas storage facility exacerbated the situation, and saw prices spike to USD 30/MBtu. In response, industrial demand was curbed, for example in fertiliser production, glass making and electricity production which shifted to coal. Gas-fired power consumption was down almost 3%, with a corresponding rise in coal-fired power, in the context of year-on-year electricity market growth of about 2%. Coal use continued to grow in 2006. Import infrastructure was in place but contractual issues limited its use, at least initially. High prices have been a powerful incentive to expand importing infrastructure rapidly, which has indeed occurred in 2006 and early 2007. Curiously, the high prices did not draw incremental gas from the lower-priced continent, despite unused transportation capacity linking the two markets.

Gas storage

Gas storage is the physical stockpiling of natural gas. It is used by gas companies to match variations in supply with variations in demand. The variations of supply with demand occur over different timescales and so are matched using different forms of storage.

At LNG receiving terminals, tankers arrive every few days to discharge their cargoes of LNG into short-term[6] storage tanks, from where it is turned into a gas and sent out to consumers at a more constant daily rate.

Gas demand increases in the evening (for example from cooking) or to meet peak power demands, so short-term underground storage is used to increase supply or to increase provision to gas-fired power stations. These daily or diurnal variations are relatively predictable.

Over the course of a year, a regular flow of gas imports does not fit the increased domestic use of gas in the winter compared with decreased use of gas in the summer (seasonal variation) – this variation is matched using underground seasonal storage. LNG storage can also be used to cope with periods of peak demand.

In fact, gas storage is one of a range of flexibility services that can be used in order to match supply to demand of gas. Gas producers can themselves provide flexibility services, called "swing", by producing gas at either a higher or lower production rate. Customers can also provide flexibility services, by agreeing to be interrupted a few times per year in return for lower priced gas supplies – these are interruptible contracts (see below).

Fortunately, the broad demand patterns of gas use are relatively predictable, so average winter or evening demand is to be expected by any gas company. Over the course of several years, there are also some changes in use – for example, there is a tendency across many countries for greater use of gas in summer as air conditioning is often powered by electricity generated from gas.

Low probablility: high impact events

Despite the relatively predictable nature of gas use, there is always a small chance of an event with a high impact. Some IEA countries have rules to ensure that the industry/market is able to cope with a particularly cold winter – for example a "one-in-fifty" standard ensures that companies plan for a recurrence of the coldest winter in the last fifty-year period. In such a situation, there would be demand for more gas for heating purposes and therefore a greater demand for seasonal gas storage.

However, no reasonable company would invest in an asset which is only productive once every fifty years. A gas company therefore needs an externally imposed incentive or obligation in the form of a reliability standard in order to invest in extra storage which may only be used irregularly, *e.g.* once in five decades. In the Netherlands, companies are obliged to perform to a temperature standard, with the Transmission System Operator charged with the responsibility of incremental gas provision between minus 9 and minus 15 degrees Celsius.

Governments or regulators are in a good position to weigh the cost and benefit to society of such reliability standards. A higher standard will result in greater investment but at a greater financial burden on consumers, for it is the consumer who pays in the end for this protection. Within a competitive market, a reliability standard works by requiring all companies to plan for a more severe winter than they would if there were no standard – this increased

6. LNG inventories are increased and decreased to manage daily fluctuations in supply and demand. They are not completely emptied, as removing all the -160°C liquid would let the tanks warm up to ambient temperature. In some countries, there is surplus LNG tank capacity which enables a substantial working inventory all year round.

demand drives up the price for flexibility services. In turn, more flexibility will be contracted and more storage will be built.

If a minimum reliability standard exists in a country, it is essential that companies plan adequately for that event. The market will not plan adequately if it believes that a government would intervene to ensure extra supplies if such an event were to occur. For example, if a one-in-fifty standard exists and a one-in-fifty winter occurs, it is essential that companies understand that they will have to cope on their own without external intervention. Where the gas markets of two or more countries are linked, it is advisable to harmonise these rules to avoid preferential supply of one set of customers at the expense of another.

Normal market conditions and commercial storage

As defined by the government, the minimum standard becomes normal market conditions. The amount of gas storage which must be contracted by market players in order to operate under normal market conditions is referred to as commercial gas storage. A favourable investment climate for commercial storage is essential in order to encourage companies to make these investments at the right time with the right mix of technologies. As import dependence grows in IEA regions, it is expected that more commercial storage should be built. Furthermore, as IEA countries move towards competitive gas markets, governments have a strong role to play in ensuring that the commercial incentive to build storage is not diluted by barriers to investment.

Across IEA countries, potential storage investors argue that there are some regulatory reasons they are not able to re-develop depleted fields, particularly those held by incumbent gas producers. Production licenses are difficult to transform into gas storage licenses and rules for upstream operators are often very different to rules for storage operators in the wholesale market. Part of the challenge for governments is to streamline procedures to lower these barriers. Governments also need to recognise their increased role in competitive markets to ensure that detailed demand and supply data is available to the market so potential investors can increase security for consumers by building commercial storage. NIMBY issues for onshore storage should also not be underestimated, and need to be addressed.

The logic for increased commercial storage investment is strengthening as IEA regions import more gas over longer distances, because the loss of domestic production capability usually means loss of the associated ability to increase or decrease production in line with demand (so called swing production capacity, as seen for example in the United Kingdom). As more gas is used in the power sector, there is also increasing demand for shorter cycle gas storage, such as salt caverns, in addition to the more common depleted field storage better suited to meeting seasonal variations. Regions which do not have the geological potential for domestic storage are investing in facilities in those that do.

Commercial storage investment

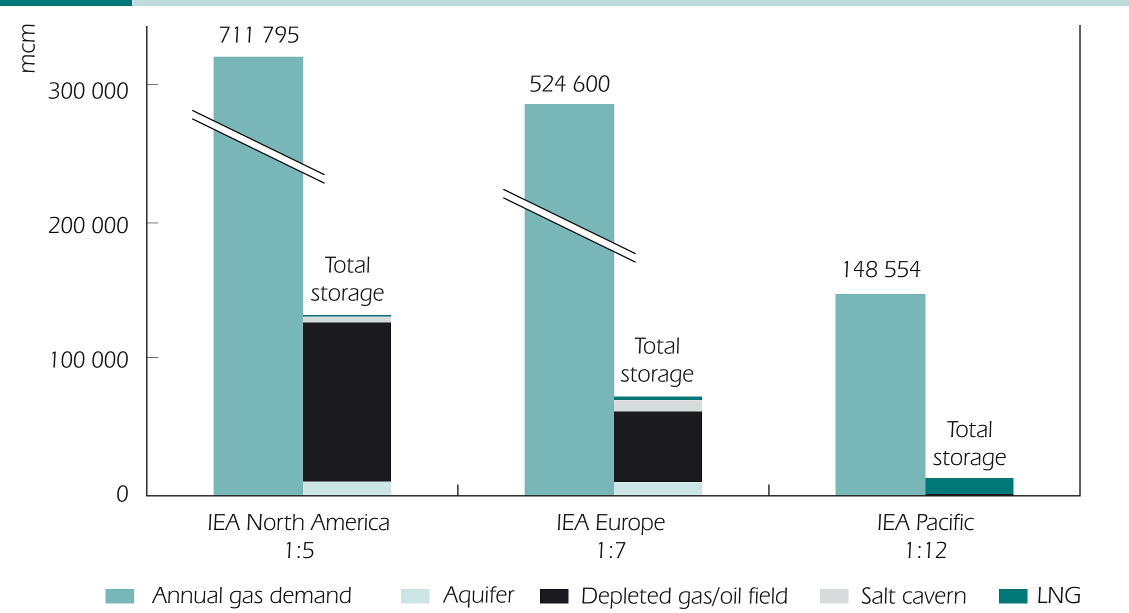
However, governments can unintentionally undermine commercial drivers, resulting in underinvestment in commercial gas storage. In competitive markets, future daily or seasonal price volatility is the primary signal for storage investors – it is also their source of revenue. Therefore government action to cap prices or artificially reduce volatility will increase the risk of underinvestment.

If governments decide to put in place strategic gas storage, all players must have a clear idea of what release policies will be adopted. If there is a perception that governments will release strategic gas stocks in normal market conditions, this would introduce a substantial risk of underinvestment in commercial gas storage. This underlines the need for Governments to impose clear responsibilities on market players and operators, within which it is a commercial responsibility to address supply issues (see Investment section).

The figure below shows the annual consumption of gas in the three IEA regions and the volume of working gas storage in each. As can be seen from the ratios of consumption to stored volume, the North American market can store more gas per unit consumption (1:5) that IEA Europe (1:7) or IEA Pacific (1:12) regions. The IEA European region - considered as a whole - encompasses countries with high storage per unit consumption and those with low storage per unit consumption. Nevertheless, as progress is made towards a European gas market, the regional average is more relevant than country-by-country data. IEA Pacific region has markedly less storage per unit consumption than other IEA regions as the two largest gas consumers, Japan and Korea lack suitable sites for underground storage.

From the perspective of market design it is interesting that the North American market, which relies only on spot gas markets to provide investment signals for storage development, has the highest degree of commercial storage per unit consumption of any IEA region, despite also having the lowest degree of import dependency.

Figure 18 IEA regional gas consumption and volume of commercial gas stocks by region, by type



Source: IEA Database.

Strategic gas stocks: what are they?

Strategic gas stocks are physical stockpiles of natural gas which are not available to the market under normal conditions. Because they are not part of the gas market, strategic gas stocks are normally owned and/or controlled by governments[7] who judge that they want to protect consumers against a non-market risk. A non-market risk is defined as a risk that cannot be expected to be covered by the market under normal conditions. A non-market risk therefore falls outside the reliability standards for a particular market. A simple example of a non-market risk in a country with a reliability standard of a one in fifty winter is the development of winter conditions more extreme than that.

Besides protecting against particularly cold winters, strategic gas stocks are also understood to offer protection for consumers against non-market supply disruptions. Such supply disruptions may be caused by freak weather conditions, such as hurricanes Katrina and Rita in the US which caused the release of IEA countries' oil stocks in September 2005.

Strategic gas stocks in themselves are only one way of providing flexibility beyond normal market conditions. They are often viewed as the "equivalent of strategic oil stocks" where in fact gas and gas storage differs markedly from oil. One of the key differences from the point of view of the user is the difference in cost.

A survey of investment in underground commercial gas storage facilities currently under construction suggests that the initial, capital cost of gas storage is between five to seven times the cost of underground oil storage facilities per toe[8] stored. The capital cost of LNG storage facilities currently under construction is approximately ten times the cost of stocks in oil tanks or approximately fifty times the cost of underground oil storage per toe stored. Capital costs of gas stocks are therefore much more expensive than oil stocks.

Assuming suitable sites could be found, the total capital cost of constructing facilities necessary to hold 90 days[9] of net gas imports in 2015 would be in the order of USD 54 billion (in 2005 USD). The cost of purchasing gas (or LNG) to fill these storage facilities would be approximately USD 40 billion (at average 2005 IEA gas prices). While it might be argued that commercial stocks already provide a part of that figure, the previous discussion has explained why commercial and strategic stocks should be separated. In fact, commercial stocks rarely exceed two months supply, and are often well below that in some countries at some times of the year. Gas stocks in Belgium, when full are equivalent to two weeks' consumption.

According to IEA research, variable costs for maintaining gas in storage are also significant. The variable cost of maintaining enough gas in strategic storage to satisfy a 90-day net import standard across the IEA is USD 5.4 billion per year (2015 capacity). Variable costs

7. Though they are often provided by companies, eg through government tendering process.
8. Toe = Tonne of Oil Equivalent. An energy equivalent of one tonne of oil.
9. Assuming countries without geological sites built LNG tanks; 90 days is a period chosen for example.

for gas storage are determined by various economic factors such as interest rates, maintenance, and cost of personnel, but also include another factor specific to gas storage – gas leakage. Gas leaks at slow rates from high pressure underground storage but the rate differs depending on the geological structure. Commercial storage sites undergo a full cycle of filling and emptying at least once a year, so it is difficult to estimate the rate of leakage for a gas facility which may be full for several years before being needed. We have used a leakage rate of 2% per annum, which we consider to be conservative.

It is worth also noting the practicalities of putting in place such massive gas storage – it would take a long time and have an appreciable impact on the global gas balance. Absolute minimum lead time for conversion of a depleted field into a storage site is two to three years (onshore and offshore respectively). The volume of gas needed to fill enough storage for 90-days net imports for all IEA countries in 2015 is equivalent to the entire 2008 combined gas exports of both Canada and Norway. Of course, the additional demand for filling this storage requirement is likely to be best met by new greenfield production, but new project development takes almost a decade from proven reserves to first gas.[10]

The release rate of gas from existing commercial depleted field storage sites is similar to the release rate of oil from underground strategic storage, approximately 1-3% of total volume per day. Similarly to oil tanks, LNG tanks have much higher release rates of up to 50% per day. Gas storage in salt caverns is a "middle ground" between these extremes, as the injection and withdrawal rates are higher than depleted fields but the costs are lower than for LNG. However, salt storage is only possible where large salt deposits exist.

As with IEA oil stocks, it is likely that a mix of fast and slow withdrawal gas storage would be needed in order to enable a complete strategic gas storage capability with a range of withdrawal rates. Building a range of storage types including salt caverns would increase the cost of constructing storage facilities for an equivalent volume of gas beyond USD 54 billion.

Why do gas stocks cost so much more than oil?

The principal reasons that gas stocks are so expensive compared with oil are two-fold. Natural gas, like any other gas, needs to be fully contained at all times to prevent it mixing with the air and/or escaping. As well as needing confinement, natural gas has a lower energy density than oil which means that, at standard temperature and pressure, a volume of gas contains much less energy than the same volume of oil. To be economic for storage, the energy density of gas must be increased – gas must therefore be stored either at very high pressures or at low-enough temperatures that it forms a liquid.

High-pressure environments require specialist materials such as thick steel pipelines and powerful compressors. When using depleted fields for gas storage, the pressure

10. The largest IEA green-field gas project due to commence production in 2007 is Ormen Lange whose reserves were proven in 1997. This development cost some USD 10 billion and will account for approximately a quarter of Norwegian exports in 2008.

of the field has to be maintained at all times otherwise the geological structure could be altered. This means that even when the field is technically empty of working gas it must have sufficient gas in store to maintain high pressure. The volume of gas left in a gas storage site emptied of useful working gas is referred to as the "cushion gas". The volume of cushion gas required to develop a large underground storage can account for up to half the cost of the investment.

Cooling gas to liquid form (-160ºC) requires considerable energy and confining it requires specialised materials such as nickel/steel alloys. At -160ºC natural gas is a boiling liquid, so small amounts escape as a gas. Cooling the gas back to a liquid and returning it to store uses energy, and adds to costs. In some cases the "boil-off gas" is consumed for useful purposes instead of being re-liquefied, but in that case it must be replaced - again adding to costs.

Handling difficulties mean that gas needs specialised equipment to get it into or out of store. Operating costs for gas storage are also well beyond those of oil storage, but it is difficult to give a range because this depends on the cost of energy to drive compressors and pumps.

The cost of purchasing the gas to fill the store is considerably lower than the capital cost of constructing the facilities needed to hold it. The price of gas is usually similar to, or slightly lower than the price of crude oil (per ton of oil equivalent) but actual prices depend on various factors including the consuming country and the time of year.

Why are gas stocks less effective than oil stocks?

There may be a few specific risks that countries decide that they want to ensure against, for example one part of the gas system regarded as particularly vulnerable. Where this is the case, then strategic stocks can be built to guard against the specific risk; for example to manage risks of a supply disruption to a major trunk pipeline system or damage to a particularly important part of the gas supply infrastructure. If geology allows, a storage site can be selected near the off-take point of such a pipeline system, designed specifically to match the nature of a potential disruption. In these cases, gas storage could be extremely effective in mitigating specific risks. Nevertheless, strategic gas storage suffers from some of the disadvantages of strategic oil stocks – namely that suitable geology must be found for underground facilities and that strategic stocks carry a risk of discouraging investment in commercial storage.

In order to address a wide spread of risk factors, encompassing the increased volume and distance of imports, it is important to recognise that strategic gas stocks may be less effective than strategic oil stocks. These arguments have been summarised below.

- Downstream gas transport is always performed by fixed infrastructure. Strategic gas storage will therefore be ineffective if transport infrastructure is damaged between the storage site and the customer. This argues for placement of strategic storage near to consumption centres.

Example: While there are many downstream oil distribution pipelines in use, a large scale disruption to one could be isolated and replaced with tanker trucks. Smaller oil leaks can be detected much more easily than leaks on gas pipelines since gas leaks just escape into the atmosphere. Repairs to oil pipelines are also less costly than repairs to gas pipelines because of the elevated pressure of the gas system. Gas is rarely transported to consumers in trucks, which means that the distribution system is less resilient. Where oil tanker trucks are used instead of pipelines the loss of a tanker truck will hardly affect the distribution of oil. If any part of a major gas trunk pipeline is destroyed, supply downstream to a whole region is stopped until the damage can be repaired or the pipeline replaced, alternative arrangements by road are not an option.

- Gas transport is less capable of being scaled-up than oil transport. While there is an option of building dedicated infrastructure for use only by strategic gas storage, the ideal location for gas storage is much closer to the consumption site than for oil.

Example: At times of extreme oil demand, more oil trucks can deliver more oil to petrol stations via the road system. Moreover, there are generally empty tanker trucks available at any one time in any one region. At times of normal winter peak gas demand, underground pipelines cannot carry much more gas. It is therefore much more difficult to increase the amount of gas distributed to consumers in times of crisis than it is to deliver more oil to consumers. If the disruption is due to action by a producer, then oil stores in the consuming country can be mobilised to any demand centre. If upstream gas supplies are disrupted, poorly interlinked markets, such as Europe would be unable to release gas storage across for the benefit of the region.

- Excess gas transportation is more expensive than oil transportation. This means that strategic gas storage would have to use existing gas transportation infrastructure, so more strategic storage sites are required to cover every potential supply disruption.

Example: The largest LNG tanker is the "Qatarmax" class vessel which costs four to five times more than an oil tanker carrying a similar amount of energy, *e.g.* Aframax (USD 65 million). On a small scale, increasing the capacity of a gas distribution network is much more expensive than building a series of petrol stations. Long distance gas pipelines have to withstand far greater pressures than oil pipelines, which also makes them up to five times more expensive. Building surplus gas infrastructure costs much more time and money than oil. Repairing damage to gas infrastructure is similarly more costly.

- Fixed gas installations, which might be damaged by extreme weather events, cannot be easily bypassed. This means that strategic storage must be physically built near to physical interconnections of major pipeline systems or that expensive physical interconnections must be built near to strategic storage.

Example: Oil has a much more robust and interconnected infrastructure than does gas; oil receiving ports, storage sites and refineries can be lost to the regional distribution system and replaced to a certain extent by increased transportation to or from other installations. The loss of one gas distribution pipeline can not be replaced by quickly building an alternative. In order to isolate a damaged gas facility or gas pipeline, the market must be very well interconnected to other potential supply sources via a web of pipelines. In this respect, the physically interconnected North American and Korean markets and the Japanese market, interconnected by LNG, are better off than the largely national markets of the IEA European region, with its limited physical and contractual interconnectivity.

- Summary. Gas stocks are not as effective a solution to general supply disruptions as are oil stocks, though they may be well suited to mitigate specific risks in certain countries or as part of a suite of other measures.

Oil stocks can quickly be released in the case of an emergency from any site to cover a supply shortage anywhere within a reasonable distance and can rely on a flexible transportation system to bring them to local or even global markets. Even in well interconnected gas markets, stocks could not rely on such an extensive global transportation network. This means that gas stocks might not be in the right place to manage a supply disruption.

What are the other options besides strategic stocks?

Where markets are liberalised, prices can rise in the event of disruptions, producing both supply and demand side responses in the market. In the absence of such markets, different tools will be required. Even when markets are working well, governments may use some of the tools discussed below where economies may be severely damaged. Many of these tools will also be present in well functioning, competitive markets, where market based mechanisms can act as policy levers to create an optimum balance.

Supply response

Gas markets with access to spare import capacity from LNG terminals or unused pipeline capacity might be able to benefit from some type of supply response to a gas emergency if contractual circumstances permit.

In the pipeline market, this response would rely on their being unused pipeline capacity with associated production flexibility. IEA Europe for example, had a total import capacity of over 350 bcm in 2005,[11] yet only received imports of slightly over 200 bcm. Some of this import capacity can be used by the capacity owner to increase purchases from upstream suppliers, if supply is available and contractual conditions allow.

In the LNG market, a supply response would have to rely on purchase of additional LNG tanker cargoes as most LNG contracts specify limited buyer flexibility (this is changing slowly – see LNG chapter). There are two sources of available LNG cargoes:

- The “spot” LNG market.
- LNG cargoes diverted from original destination by agreement of stakeholders.

As the LNG spot market expands, a flexible supply response is possible into each regional IEA market. Spare LNG receiving capacity was present in all IEA regions in 2005 and is expanding. With spare capacity, regions could buy gas from the uncommitted “spot” LNG market. However, this market is global, meaning that increased buying by one region reduces supply in the other two. In the event of a supply disruption, the "spot" LNG market might not be large enough to meet demand, and so reliance on the spot market alone is likely to be insufficient for major supply shortages.

It must be remembered that the LNG market is growing in size and flexibility even outside of the spot market. In 2005 it was already flexible enough to handle large-scale disruptions to traditional contracts such as those resulting from the Indonesian supply shortfall – 11% of cargoes from the worlds largest LNG producer were replaced in this way.

Most LNG production trains run at less than 100% capacity, but it is possible within the framework of existing long-term LNG contracts for customers to request that suppliers increase production. Where traditional relationships are in place, this arrangement can increase the total volume of LNG supplied to the buyer. LNG cargoes can also be released from servicing their normal obligations under long-term contracts and diverted to alternative destinations, if both buyers and sellers agree. This would, in effect swap cargoes from the long-term contract market into the global "spot" market, but would only be a net gain in supply if the buyer was also able to decrease domestic demand.

A combination of demand reduction in unaffected regions, plus increased production and cargo diversion could constitute a global LNG response to a supply emergency. Where gas markets rely on LNG supply response in case of a supply disruption, careful evaluation of this global market is needed in order to understand the international linkages between buyers and sellers which have made the LNG market what it is today.

The gas market has a history of strong collaboration between buyers and sellers, so dialogue with producer countries is vitally important. As more gas is traded worldwide, it is increasingly important for the globalising industry to get transparent, reliable information about investment and production plans. Dialogue with producing countries in order to secure supply flexibility is as important in gas markets as it is in oil markets.

Demand response

One way of rationing the use of gas with predictable economic impact is through demand response. Demand response occurs when customers decide to modify their consumption depending on the price of gas in a market. Two examples (explained below) of such a response might be chemicals manufacturers, *e.g.* in the fertiliser industry, and merit order flexibility in the power market.

There is a global market for industrial chemicals such as fertiliser, so by comparing the global sales price to the price of production, a company can decide to temporarily stop making fertiliser locally; switch production to an offshore plant and import the product or buy fertiliser from

11. Source: Gas Infrastructure Europe (GIE) and IEA data.

the global market and deliver locally. This appears to have been the major response mechanism in the North American market after the hurricanes in 2005.

Another example of this behaviour is in the power sector where changes in the relative price of fuels (coal, gas and oil) can result in changes in the merit order. This means that (all other things being equal) as gas prices rise, there is a preference to reduce gas demand and increase power generation from coal, oil or nuclear units where spare capacity exists. In efficient power and gas markets, it is possible to get good demand response to a gas crisis as higher gas prices reduce consumption. This appears to have been the mechanism by which the United Kingdom market reduced gas demand after a fire at the principal storage facility in 2006.

In some cases, there is often a time lag between wholesale price changes filtering through to certain classes of consumer, for instance in the residential sector. This time lag might justify government action to make domestic gas consumers aware of a supply disruption. Short-term gas saving measures might be required to reduce demand over relatively short periods. Given the increasing use of gas in power generation, these measures should also consider stimulating action in the electricity sector (*Saving electricity in a hurry*, IEA 2005).

Those countries with gas prices determined by supply and demand would see an automatic reduction of consumption of gas as the price increases. Where price is determined by some other means, this would not happen. In any case, government measures might need to be considered to promote demand reduction in sectors not exposed to short-term price changes.

Interruptible customers

These are industrial customers who consume large volumes of gas per year and agree to have their gas supply interrupted for a maximum number of days in a year in order to obtain a reduction in gas price. On average, customers with these contracts agree to a maximum of 10-20 days of zero supply (if necessary) in a year. Whilst interruptible customers are certain to have their gas supplies cut in a supply disruption, the volume saved is unlikely to be sufficient to completely mitigate large-scale disruption. Nonetheless, this option can be useful as part of a suite of tools for dealing with such interruptions.

Direct rationing

One option which has been used by IEA countries is government-determined rationing. This option requires careful preparation by governments in consultation with users and industry to identify costs, capacities and legal/technical issues well in advance of activation of the plan. Planning such as this needs to be regularly tested and updated because gas markets and their dependents (such as electricity markets) tend to change rapidly. In the absence of functioning gas markets or if a disruption is very large indeed, such actions may be an important crisis management tool.

Fuel switching

There is a class of gas customers who exhibit a very useful type of demand response for managing a gas emergency situation as they can rapidly switch what fuel is burned to power the same equipment. This means that the response is faster and there is less potential disruption to customers than in the case of a demand response from shutting production and relying on imports of the product. In most cases, the choice of alternative fuel is technically limited to oil or oil products, as oil can be injected into gas turbines or sprayed into boilers (this is rather more difficult for coal). While there is a penalty in terms of efficiency and increased maintenance, some gas-fired power stations in Europe[12] and North America can often switch to light oil (gasoil) and some in Korea and Japan can often burn crude oil if necessary. In order for these plants to switch fuel, several conditions must be met[13] – above all, there must be adequate stores of oil available at the site.

Equipment such as dual fuel burners and oil stocks are expensive, so there must be adequate incentives if companies are expected to maintain such investments. In competitive markets, companies often make generation decisions based on fuel costs and therefore have some financial incentive to maintain oil storage and dual firing capability. However, if dual firing capability is imposed by the government, it is tempting for companies to save money by for instance, storing less oil than governments may deem prudent.

The potential for gas saving through fuel switching clearly depends on the amount of dual firing capability in any given region or country, noting differences in costs and response times. Differences in oil and gas prices are not possible if gas prices are determined by oil prices, such as in much of continental Europe (Japan and Korea less so). This means that fuel switching capacity would have to be imposed administratively (by gas companies or by governments). In this situation, fuel switching should be tested regularly to ensure capability.

Conclusion

All three IEA importing areas are now importers of natural gas and each will import more natural gas in 2015 than in 2005. Gas will increasingly come to market across longer supply routes from countries with more abundant reserves.

Natural gas is very important for basic functions of heating and cooking. It is becoming more important for power generation, and is also used as a chemical feedstock for industrial processes. An ideal emergency response to a natural gas supply crisis would result in gas saving (from lower demand) in all of these applications, but particularly from low value-added industrial processes such as basic industrial processes.

A prolonged gas supply disruption could have a very high impact on IEA member countries. It is clear that physically interlinked markets such as North America or virtually interlinked markets such as Japan and Korea can better survive supply disruptions, especially of the smaller type. A disruption of 2 bcm in an isolated market

12. Switzerland has one of the largest switching capacities of in IEA countries, with 40% of gas demand (by volume) mandated to be technically able to switch to oil if necessary, and with a reserve of 40 days of oil.
13. *E.g.* Environmental conditions: emissions permits; marginal cost considerations; contractual arrangements etc.

of 10 bcm will have serious implications; the same interruption in a continental sized market of 500 bcm can be much more easily handled. It is therefore imperative for IEA countries to actively encourage larger, more interconnected gas networks that are driven by flexible gas markets, capable of responding to changing circumstances.

Whilst the development of interlinked gas markets in many IEA countries remains slow, there is a greater risk of impacts from a supply disruption, so alternative (temporary) approaches should be identified. Where markets function well, there is still a chance that non-market events might occur. This means that supplements to the market should be carefully considered; provided that such measures stand apart from the market so that they do not crowd out commercial investment.

The logistical and political risk of a natural gas supply disruption is increasing. Indeed – some IEA countries already have emergency response mechanisms, including government-controlled storage. Therefore, there is a compelling case for all countries to develop some kind of emergency response mechanism for natural gas markets. Countries should ensure that all stakeholders – including suppliers, national and local pipeline system operators, regulators and consumers – have clearly-defined roles and responsibilities in a crisis.

Governments are well advised to put in place emergency response mechanisms for gas supply disruptions which draw on the above suite of measures and which look beyond just strategic gas storage as a general solution to a gas crisis; gas stocks are more expensive, less flexible and less effective than oil stocks. In certain circumstances, however, gas stocks may be part of an effective gas emergency policy – particularly to insure against a specific disruption at an identified weak point in the system.

The IEA advises:

- those countries with no explicit gas emergency policy to put one in place in order to mitigate the effect of the loss of the weakest point in the system for a reasonable repair period.
- those countries with an emergency response mechanism to check its effectiveness regularly, as the gas market is developing globally and changing rapidly.
- all countries to use a mix of measures in a gas emergency response plan. If gas stocks are a part of such a plan, to ensure that they are as cost-effective as possible.

The IEA advises all governments, in concert with other stakeholders to:

- clearly define, through a reliability standard or some other means, exactly what is expected of actors under normal market conditions.
- carefully design an emergency response mechanism drawing on a full suite of measures which does not affect commercial investment driven by the gas market.
- clearly define the role and responsibility of every stakeholder under an emergency response mechanism.
- ensure that the conditions under which an emergency response mechanism will be used are transparent to the market.
- make use of market mechanisms wherever possible, in order to ensure

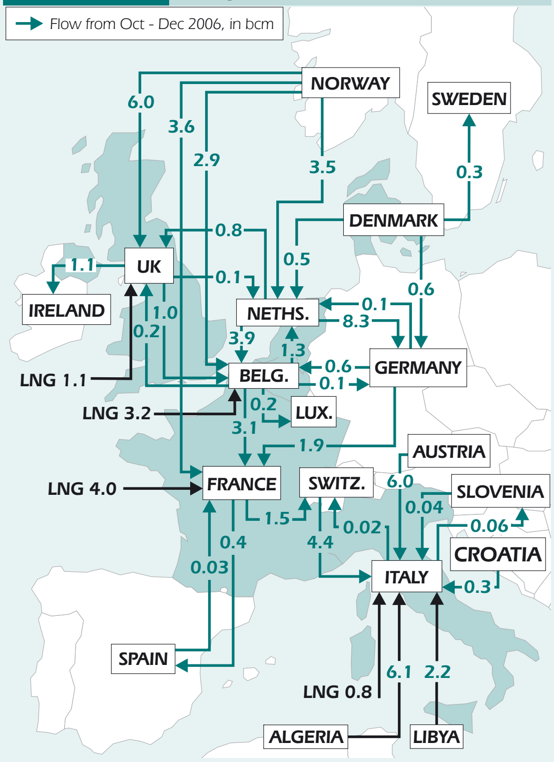
emergency response mechanisms are cost-effective.

- consider the international consequences of their emergency response mechanisms, including the consequences for regional power markets and the global oil market.
- secure in advance statutory powers that might be necessary to implement emergency measures.

Some examples of gas security policies in IEA member countries are at Annex A.

Data transparency initiative

Figure 19 **Physical, international flows for pilot countries**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA pilot study.

Data in the gas industry is poor, notably in IEA Europe. Much more needs to be done to improve transparency of gas flows, within and across frontiers, both physical and contractual, if member governments are to understand how their markets might function in an emergency. The IEA already has an important initiative in this area, with some key results set out in the Annexes. As part of efforts to increase transparency in IEA Europe, more detailed data collection is now being attempted.

All IEA countries are interested to improve data availability in IEA Europe given the increasingly global interactions of regional markets. All LNG importing regions will benefit from greater understanding of gas flows and market functioning in this region.

The Annexes provide an overview of best available data showing imports and exports to all three IEA regions. Figure 19 provides a complete picture for a selection of six highlighted European countries who participated in an IEA pilot study. The trade shown below summarises physical gas flows at European borders over the last quarter of 2006.

DEVELOPMENTS IN LNG MARKETS

- Global LNG production capacity is set to grow rapidly and LNG will make up 14% - 16% of global gas demand by 2015. The majority of gas sector investment has been focussed on developing LNG production. In Japan and Korea, LNG will retain its central role but for the North American and European regions, LNG will be an essential supply source.

- 2006 saw world LNG production grow by 11% to 218 bcm, continuing the strong growth that has seen output increase by more than 50% in five years. Qatar surpassed Indonesia as the world's largest LNG exporter in 2006, exporting 33 bcm.

- No final investment decisions for any LNG export projects were made in 2006, reflecting the difficult investment environment caused by a tight engineering market and cost increases.

- Regional price movements have driven some "globalisation" of gas trade commodities, particularly from the Atlantic to Pacific regions, although volumes remain relatively minor. These movements have also been facilitated by the changing business models of the LNG industry. This trend will accelerate even further because a substantial number of more flexible exporting plants, which could supply cargoes to both Atlantic and Pacific LNG markets, are to be installed in Middle East countries.

Overview

The rapidly changing world of LNG

2006 saw world LNG production grow by 11% to 218 bcm, continuing the strong growth that has seen output increase by more than 50% in five years. Qatar surpassed Indonesia as the world's largest LNG exporter in 2006, for the first time since 1984 when Indonesia took the place of Algeria. Qatar exported 33 bcm of LNG in 2006, followed by Indonesia's 30 bcm and Malaysia's 28 bcm.

China and Mexico started importing LNG in 2006. Gazprom entered the LNG business, taking its first majority equity stake in an LNG project, Sakhalin II, late in 2006, and selling spot LNG cargoes into Asia for the first time in summer 2006.

In early 2007, a USD 1.5 billion construction contract was awarded for a 6 bcm per year liquefaction plant on Peru's southern coast, the first on South America's Pacific coast, to Chicago Bridge & Iron (CB&I). The project's partners are Hunt Oil, Spain's Repsol, and Korea's SK Corporation. The Peru project represents the only new project sanction for the period June 2005 to March 2007.

No final investment decisions for any LNG export projects were made in calendar 2006, the first year with no announcements since 1998. This reflects the difficult investment environment caused by a tight engineering market and cost increases.

The first dockside LNG regasification terminal began operations at Teesside in northern England in February 2007, with a remarkably short lead time (roughly one year). Turkey started using its first receiving terminal built by a private company, not state-controlled Botas, virtually forced to do so by significantly reduced pipeline gas delivery from Iran in the winter 2006/07.

Norway imported its first LNG cargo at the beginning of 2007. This was to commission its first LNG liquefaction facility, also the first within the Arctic Circle, the Snøhvit project.

30 newly built LNG carriers were delivered to the market in 2006, representing a 16% increase in total LNG fleet in the world and a 19% increase in total shipping capacity.

Korea's residential gas sales were down in 2006 due to warmer-than-normal winter for the first time since the country started importing LNG in 1986, although imports grew some 10% on the back of the power sector. Japanese imports were also up more than 6%, despite warmer weather reducing demand in certain sectors, especially early in 2006.

LNG production will steadily grow and flexibility will increase

Global LNG production capacity is set to grow rapidly from 240 bcm per year in 2005, to 360 bcm in 2010, and 500 - 600 bcm per year by 2015, growing by 7.5-9% a year. LNG will make up around 20% of OECD gas supply as soon as 2010, and 14 - 16% of global gas demand by 2015. The majority of gas sector investment has been focussed on developing LNG production. 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.

Regional price movements have driven some "globalisation" of gas trade, although volumes are relatively minor. These movements have also been facilitated by the changing business models of the LNG industry. Traditional LNG trades have been done between designated sellers and buyers. Today, more integrated oil and gas majors and national oil and gas companies are securing their own long-term LNG supply first through upstream equity holding and/or contracting. They then directly market LNG cargoes into multiple outlets. While many of the outlets are secured also on long-term basis, they tend to have more flexibility in diverting cargoes to different places. These trends naturally increase the ratio of cargoes counted as "spot," although originally contracted on long-term basis.

This trend will accelerate even further because a substantial amount of more flexible (hybrid) exporting plants which could supply cargoes to both Atlantic and Pacific LNG markets, are to be installed in Middle East countries, notably in Qatar, and also substantial shipping tonnage is going to be delivered in the coming years. Such flexible capacity in the Middle East could represent 25% of the global LNG exporting capacity by 2015.

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

Japan is currently the largest LNG importer in the world and Korea the second. By the end of the review period, however, the Atlantic LNG market will grow to at least equal, or may even surpass, the Pacific market. Shares of Japan and the Pacific will decrease during the period, potentially dropping from 42% and 66% in 2005 to 16% and 35% by 2015, respectively. Middle Eastern LNG exports, having similar distances to either market, will increasingly link the Pacific with the Atlantic, carrying price signals between them. More regasification capacities are planned in the more liquid Atlantic gas markets, which is also likely to contribute to greater flexibility in cargo movements.

Figure 20 Traditional and recent models of LNG business

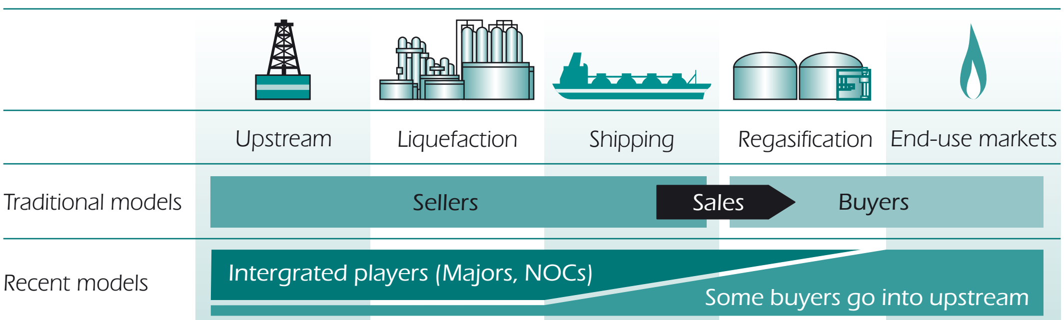


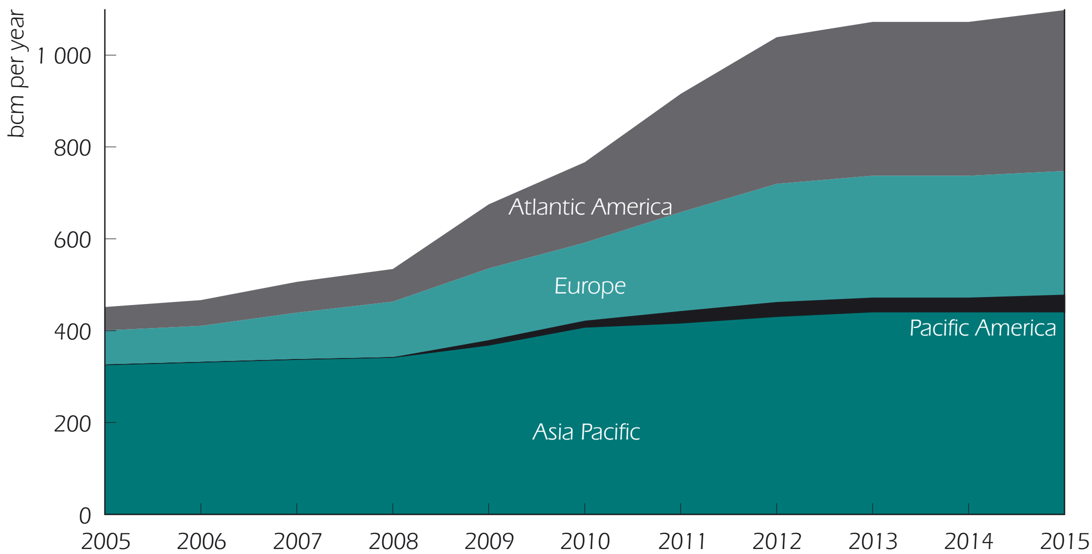
Table 9 Countries and regions involved in international LNG trades

Import	Atlantic	Pacific
1964- 2000	United Kingdom (1964-1994), France (1964), Spain (1969), Italy (1969), United States (1971), Belgium (1987), Turkey (1994), Greece (2000), Puerto Rico (2000)	Japan (1969), Korea (1986), Chinese Taipei (1990)
2000-2006	Dominican Republic (2003), United Kingdom (2005), Mexico (2006)	India (2004), China (2006)
Future	Canada (2009), Brazil (2009-2010), Netherlands (2010)	Chile (2010), Mexico (2011), Thailand (2012), Singapore (2012)

Export	Atlantic	Hybrid (Middle East)	Pacific
1964 - 2000	Algeria (1964), Libya (1970), Trinidad (1999), Nigeria (1999)	Abu Dhabi (1977), Qatar (1997), Oman (2000)	Alaska (1969), Brunei (1972), Indonesia (1977), Malaysia (1982), Australia (1989)
2000-2006	Egypt (2005)		
Future	Equatorial Guinea (2007) , Norway (2007), Angola (2010), Russia (2012), Venezuela (2011)	Yemen (2009), Iran (2011)	Sakhalin (2008), Peru (2009), Myanmar (2013), Papua New Guinea (2013)

*For future importers and exporters, the year in the parenthesis indicates earliest possible start date.
Source: IEA data.

Figure 21 **Expected regasification import capacity by region: regas capacity is ample**



Source: Company announcements, moderated by IEA analysis.

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

Two thirds of Spanish gas demand is met through LNG imports, making it the third largest LNG market after Japan and Korea. The Spanish market has grown at around 15% per year, with two terminal expansions and one new terminal completed in 2006 and further expansions are expected to be online in 2007. In Italy, where only one LNG import terminal is currently in operation, two more are under construction. Each of these countries makes extensive use of gas in power generation (the two countries added 4 GW of gas-fired power generation capacity each in 2006) and also has plans to increase pipeline infrastructure. The availability of LNG terminals allows Spain to draw on a diverse range of gas supplies; by contrast Italy is heavily reliant on pipeline supplies from Algeria and Russia, accounting for 61% of total gas demand. In the United Kingdom, two new onshore LNG terminals are being built and existing capacity is being upgraded.

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; accounting for 15% of the 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 the North American gas supply. By the end of the review period, LNG will supply up to 9% (80 bcm per year) 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.

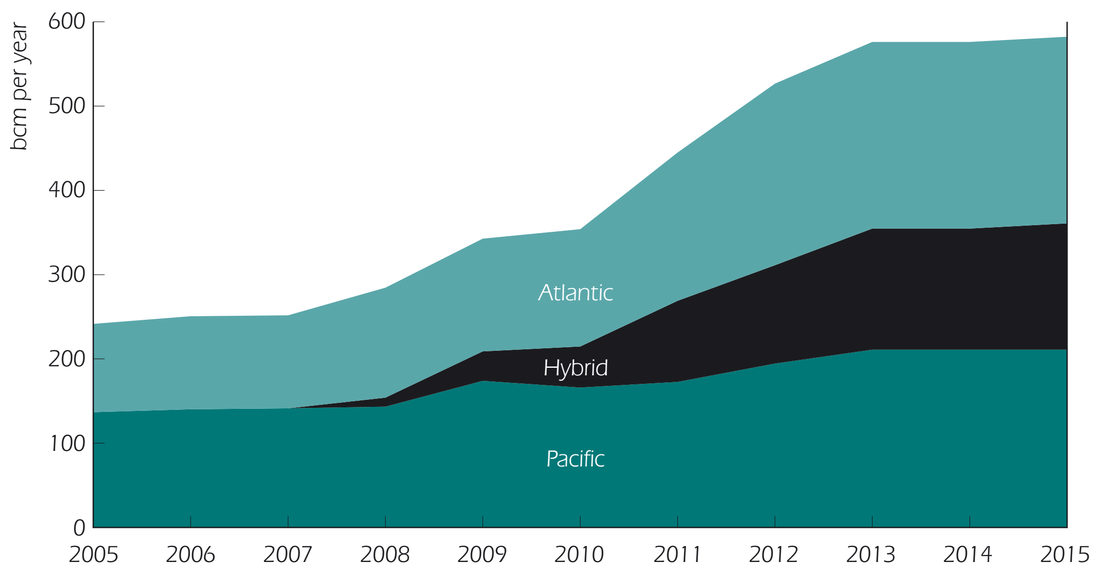
China and India represent massive latent demand for gas at lower prices

Chinese gas demand was only 3% of primary energy use in 2005 and is virtually all satisfied by domestic production. The current high international price environment has slowed construction of infrastructure necessary to provide growth in gas use. LNG imports commenced with the inauguration of the first terminal in 2006 in Guandong. A second terminal in Fujian should start receiving LNG in 2008, with another in Shanghai, scheduled for 2009. 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. LNG imports seem unlikely to exceed 40 bcm per year by 2015. This means that the vast bulk of LNG will be consumed in IEA countries.

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

Qatar emerged as the world's largest LNG producer in 2006 and its share is rising rapidly, with its first "mega" liquefaction facility expected to be online in early 2008. It could supply more than 20% of the world LNG market in 2010 as a result of successful

Figure 22 **Expected LNG export capacity by region**



Source: Company announcements, moderated by IEA analysis.

efforts to attract overseas investment in its abundant reserves. Qatar is positioned to sell its huge volumes into both Atlantic and Pacific markets, further linking these gas markets.

Meanwhile, Indonesia, which currently supplies a quarter of Korean and Japanese gas demand and was the world's largest LNG producer, lost its title to Qatar in 2006. A lack of investment in gas production 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 further reduce gas availability for exports.

Production

Indonesia is diminishing its dominant position in Asia

Indonesia, which has dominated the Asia-Pacific LNG market since its first LNG export in 1977, is decreasing exports after peaking at 38 bcm (28 million tonnes) in 1999 and 35 bcm (26 million tonnes) in 2003. Not only the North Sumatra Arun liquefaction plant, where gas reserves are dwindling, but also the country's flagship Bontang venture in East Kalimantan, are both showing disappointing performances in LNG production. Indonesia is expected to export 11% less than previously contracted in 2007. Some buyers are busy replacing the anticipated losses for the next couple of years. The country does not expect a significant increase in LNG production until the scheduled start up of the Tangguh plant in 2008 (see details below).

Australia is emerging as a greater force

With declining LNG exports from Indonesia, Australia is gaining momentum towards a greater share of the Pacific LNG market, with the addition of a brand-new exporting plant at Darwin (Northern Territory) in 2006, the first since the opening of the North West Shelf in 1989 (now operating at 16 bcm per year), and several grassroots and expansion projects are on the horizon for starting in early 2010s. Though there are some hurdles to clear, including environmental agreements, high construction costs, and State-based policies of domestic resource usage, project fundamentals are generally good.

Starting Bayu-Undan export

The Darwin LNG project started exporting LNG to its Japanese customers in early 2006. The project is unique in a couple of aspects: the feedgas is the first provided from the joint petroleum development area (JPDA) between East Timor and Australia where other gas reserves have been identified; the project size is relatively small (5.0 bcm per year (3.70 mtpa)) in this era of mega projects; participation from long-term buyers in Japan into the whole value chain encouraged the development; and early extraction of natural gas liquids (NGLs) was critical to the project. Plenty of space and potential feed gas sources for expansion are available, as approvals have been granted for up to 13.6 bcm per year (10 mtpa). Unusually for Australia, the plant is well-located, close to existing infrastructure of the city of Darwin.

Figure 23 **Australia's LNG projects**

Source: Company announcements, The Petroleum Economist Ltd.

Pluto: progress in marketing and engineering

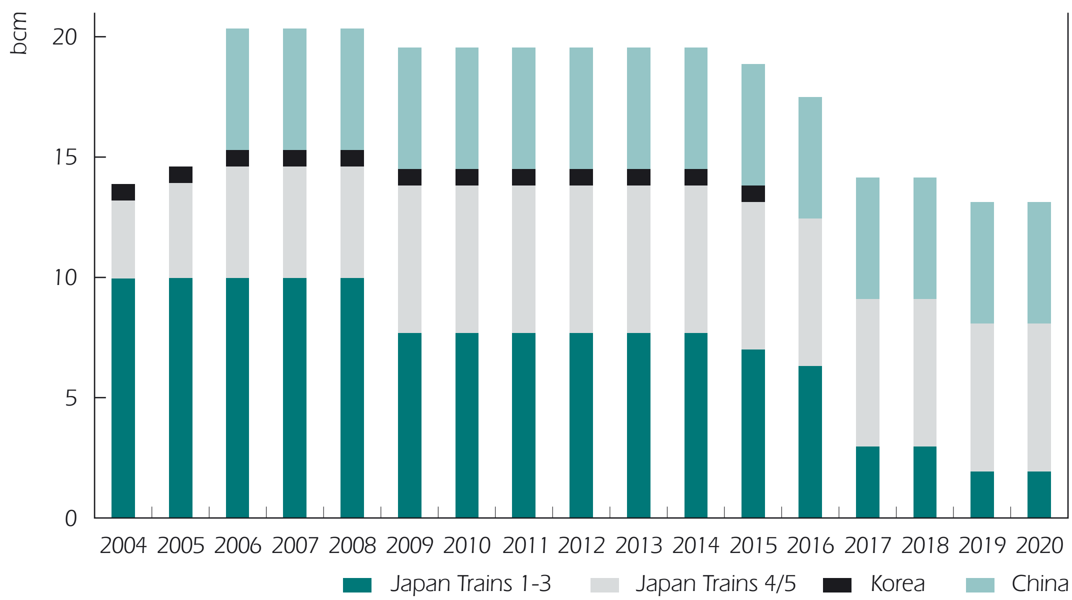
Quick progress has been made in marketing and engineering of the Woodside's wholly-owned Pluto project, close to the existing North West Shelf plant on Burrup Peninsula, since the company discovered significant reserves in the field in April 2005. After securing commitment from Japanese buyers late in 2005, the company started front-end engineering and design (FEED) work in fall 2006, targeting commencement of the project in 2010. This ambitious schedule would amount to one of the fastest LNG exporting projects ever developed. The project may keep 1.3 bcm per year (1 mtpa) of its output for flexible marketing out of its planned capacity of 6.8 bcm per year (5 mtpa).

The company started site preparation work for storage tanks of a standalone liquefaction plant in early 2007, after its request to share facilities with the existing North West Self venture was declined. The final investment decision is expected in mid-2007.

Gorgon: progress but some environmental and cost hurdles

Marketing efforts of the Gorgon LNG project, which has been mooted for more than 15 years, made considerable advances in late 2005 by signing up buyers from Japan for the operator Chevron's share of output. The project generally enjoys support from state and federal governments and is on the way to start exporting in 2011 from the planned 13.6 bcm per year (10 mtpa) plant

Figure 24 North West Shelf's long-term sales commitments



Source: Company information.

on Barrow Island off Western Australia. The Gorgon partners – Chevron (50%), Shell (25%) and ExxonMobil (25%) – have been marketing their equity LNG separately.

High CO_2 content of the feedgas and environmental siting issues as well as engineering and cost issues, may still delay this development. The state government gave environmental approval to the project in December 2006. The final investment decision, which was initially targeted for mid-2006, is now expected in 2007, the partners have said. Marketing arrangements for the remaining capacity, assigned to partners ExxonMobil and Shell, have been less clear. Shell has indicated that it intended to send its share of Gorgon output to the company's Hazira LNG receiving terminal in India, where it has held gas sales talks with Gujarat State Petroleum, as well as Sempra Energy's 10.3 bcm per year (7.6 mtpa) Energia Costa Azul terminal in Mexico, where Shell has 50% of the import capacity. India's Petronet says it hopes to sign a sale-and-purchase agreement for term imports of ExxonMobil's share of Gorgon output by June 2007.

North West Shelf: Train 5 construction and some Train 4 glitches

The fifth liquefaction train at the North West Shelf project is under construction. The 6.0 bcm per year (4.4 mtpa) unit is on schedule for commissioning in late 2008, according to project operator, Woodside. Once it is completed, the venture will have a total production capacity of 22.2 bcm per year (16.3 mtpa), out of which the venture will have flexibility volumes of as much as 2.3 bcm per year (1.7 mtpa) to sell on the spot market. Meanwhile, the venture's occasional troubles at the newest Train 4 might cause concerns about credibility of bigger liquefaction trains (earlier trains were 2.7 - 3.4 bcm per year (2 - 2.5 mtpa) in capacity).

North West Shelf existing contract renewals

The original sales contracts amounting to 10 bcm per year (7.33 mtpa) from the Trains 1 - 3 of the North West Shelf venture with Japanese foundation buyers are expiring in March 2009. Renewal negotiations are underway with the customers, as well as with a couple of additional importers in the region, which have forced some of the foundation customers to receive smaller volumes than they currently import from the venture. Prices look to be higher but still linked to the JCC oil prices with a wider applicable range. The renewal terms only last from 6 to 12 years, compared to 20 years for all the original deals. The terms of these renewals, with increased prices, shorter duration and reduced volumes, are an indication of current market tightness.

"Major project facilitation status" on Ichthys LNG

The Australian federal government granted a "major project facilitation status" on the Ichthys LNG proposal backed by Japan's Inpex Corporation, based on gas reserves found in its WA 285-P gas block offshore northwestern Australia, in August 2006. This means that the government's "Invest Australia" arm would help advance the project through the regulatory process and identify any programs that could assist its implementation. Inpex has begun talks with potential Japanese buyers for the 8.2 bcm per year (6 mtpa) of planned output from the project, which is scheduled to come online in 2012. France's Total agreed to take a 24% interest in the project. Environmental planning is based on a site off the Kimberly coast, remote from existing infrastructure. This would be the first development in the Browse Basin. Inpex aims to start construction of the plant in the beginning of 2009, after making a final investment decision by late 2008.

Other companies, including Woodside, have extensive gas reserves in the Browse Basin, which could create a major LNG production hub. The partners are investigating options for the Browse gas fields, with a production target between 2012 and 2014. Pilbara LNG has been planned by BHP, utilizing gas reserves in the Scarborough gas field jointly owned by the company and ExxonMobil.

"Major project facilitation status" has also been given to two gas development projects in the Timor Sea being planned by MEO Australia. The projects are expected to produce around 4.1 bcm per year (3 mtpa) of LNG and 5 000 tonnes per day of methanol from offshore facilities on Tassie Shoal, a shallow area in the Bonaparte Basin, about 275 km north of Darwin. The projects are also expected to play a hub role to encourage development of stranded gas discoveries in the area.

Western Australia's new domestic gas policy

In October 2006, the Western Australian State Government released its policy on domestic gas supply. The state considers that market forces will not deliver sufficient volumes of low-cost domestic gas to meet

Table 10 **Australian LNG export project interests**

	North West Shelf	Darwin	Pluto	Gorgon	Ichthys	Sunrise	Browse	Pilbara
Woodside	16.7%		100%			33.44%	t.b.d.	
Chevron	16.7%			50%			t.b.d.	
BHP	16.7%						t.b.d.	t.b.d.
BP	16.7%						t.b.d.	
Shell	16.7%			25%		26.56%	t.b.d	
MIMI	16.7%							
ConocoPhillips		56.72%				30%		
Eni		12.04%						
Santos		10.64%						
Inpex		10.52%			76%			
Tokyo Electric		6.72%						
Tokyo Gas		3.36%	5%?	t.b.d.				
ExxonMobil				25%				t.b.d.
Kansai Electric			5%?					
Osaka Gas				t.b.d.		10%		
Chubu Electric				t.b.d.				
Total					24%			

t.b.d.: to be decided
Source: Company information.

expected future energy demand. The State will negotiate with companies to supply the equivalent of 15% of LNG production to the Western Australian domestic market. The policy emphasises the gas commitment can be met from other projects or via gas trading schemes, with the price of gas determined through commercial negotiations. The state has already negotiated an agreement under the policy with Woodside Energy for the Pluto LNG project.

The federal government and the LNG industry are opposed to the policy and consider that the market should determine how and from where gas is supplied. Most gas produced in Australia is sourced from fields in federal government waters, but is processed into LNG on land, where State approvals are required. A joint state-federal working group has been formed to examine future gas supplies and consider policy options to secure gas supplies for domestic and export use.

Alaska's Kenai seeks sales extension

ConocoPhillips and Marathon Oil have jointly filed with the United States' Department of Energy for a two-year extension of the export license of the Kenai LNG facility in Nikiski, Alaska in January 2007. The existing license expires in March 2009, with the project's sales deal with two Japanese utility buyers. The 2 bcm per year (1.50 mtpa) Kenai plant, the only LNG export facility in North America, was built in 1969 to commercialize gas reserves discovered in south-central Alaska that surpassed local needs. It was the world's first long-distance LNG export project and Japan's first imports of LNG. Since then Japan has diversified sources of supply, and Alaska's share in Japan's LNG imports has dwindled.

Brunei may expand capacity

Brunei LNG, a joint venture between Brunei government, Shell and Mitsubishi, has a five-train plant with a capacity of 9.8 bcm per year (7.20 mtpa). The Lumut export plant started operations in 1972. Long-term contracts with Japanese and Korean buyers are up for renewal in 2013. A sixth train probably with a 5.4 bcm per year (4 mtpa) capacity may be planned if more gas reserves are discovered.

Malaysia expanding sales portfolio

Malaysia LNG's Bintulu plant is one of the largest single concentrations of LNG production capacities in the world with 31 bcm per year (23 mtpa). It started exports to Japan in 1983. The majority shareholder of the three production ventures at the site is the state-owned Petronas. The exporter plans to start long-term sales to China in 2009 (to Shanghai), in addition to the existing long-term sales to buyers in Japan, Korea, and Chinese Taipei, as well as mid-term sales to India.

Yet other potential suppliers emerging: Papua New Guinea and Myanmar

Tightening supplies and rising gas prices in the Pacific LNG market are encouraging other potential suppliers, including Papua New Guinea and Myanmar to monetize their gas resources.

Papua New Guinea currently has several LNG proposals. A long-awaited gas pipeline under Torres Strait to Australia's eastern states proposed by ExxonMobil and Oil Search was scrapped in early 2007 after a major setback in summer 2006 when Australia's AGL and Malaysia's Petronas withdrew from the project – freeing up dedicated reserves for possible export in the form of LNG. Separately, Oil Search has teamed up with BG to evaluate an LNG exporting project based on reserves not dedicated to the Australian line. Merrill Lynch, Canada's InterOil and Clarion Finanz are considering LNG exports centered on a potentially major discovery in InterOil's Elk field.

Daewoo and its partners – Korea Gas Corporation (Kogas) and India's ONGC Videsh and GAIL – are considering an LNG exporting project based on resources in the Rakhine Basin, offshore Myanmar. The sponsors claim that all the LNG buyers in this region have expressed an interest to its request for proposals conducted in December 2006, in which Kogas and Japan's Marubeni were said to be selected as preferred off-takers of the LNG.

Some of Qatar's mega train volumes going to Asia

Qatar has steadily built up its LNG business since 1997 and will triple its exporting capacities from 35 bcm per year (26 mtpa) at the end of 2006 to 105 bcm per year (77 mtpa) by 2011, with the addition of a 6.4 bcm per year (4.7 mtpa) train in 2007 and six 10.6 bcm per year (7.8 mtpa) "mega" trains in the coming years. No country has ever exported this quantity of LNG, and Qatar will remain the LNG leader for many years to come. For output from those huge production facilities, the Middle East producer is going to introduce mega-sized Q-flex (210 000 m^3) and Q-max (260 000 m^3) tankers.

While the mega-train projects were originally mostly intended for the United Kingdom and United States, some of their output is likely to be diverted to buyers in Japan, Korea and Chinese Taipei. By selling some of the most recent volumes in Asia, the Middle East's largest producer is diversifying its markets in terms of both geographic, and liquid and traditional market combinations. In addition to two new Korean long-term sales of 2.9 bcm per year (2.1 mtpa) each, starting in 2007 and 2009, and a Japanese mid-term sale of 1.6 bcm per year (1.2 mtpa) from 2008 to 2012, an additional 9.5 bcm per year (7 mtpa) is on the negotiation table between Qatar and Japan. (see also discussions on the United States and United Kingdom markets later).

It should be noted that there is a major study being undertaken on the country's giant North Field on reserve integrity

Table 11 Qatar's LNG projects: traditional and mega trains

Trains	Project	Start	Capacity (bcm per year)	Originally intended destinations	Recent Asian and other diversions
Qatargas			55.4		
1-3	Qatargas	1997-1998	12.9	Japan, Spain	
4	Qatargas II	2008	10.6	United Kingdom	Chubu likely to buy 1.6 bcm per year 2008-2012
5		2008	10.6	United Kingdom	Total could divert 5 bcm per year to France, Mexico
6	Qatargas III	2009	10.6	United States	Korea likely to buy 2.9 bcm per year starting 2009
7	Qatargas IV	2010	10.6	United States	
RasGas			49.4		
1-2		1999	9.0	Korea, Spain	
3	RasGas II	2004	6.4	India	
4		2005	6.4	India, Korea	Korea buys 2.9 bcm per year starting 2007
5		2007	6.4	Spain, Italy, Belgium, Chinese Taipei	
6	RasGas III	2008	10.6	United States	Half of RasGas III could be diverted to Asia
7		2009	10.6	United States	

Note: [ ] = Mega trains. Source: Company information.

management. The study will not be completed at least until 2009, meaning that any new major project decision is only likely to be made after that. This will mean only limited Qatari production increases for the immediate period (potentially three years and upwards) after the current project load is completed in around 2011-12.

Abu Dhabi: the first LNG exporter in the Middle East

The Adgas project, a 7.9 bcm per year (5.8 mtpa) plant on Das Island in Abu Dhabi, the United Arab Emirates, dates back to 1977 and is the longest established in the Middle East. The project is majority owned by Abu Dhabi National Oil Company with foreign partners Mitsui, BP and Total. Japan's Tokyo Electric Power Company buys the majority of the plant's output on long-term basis, with some mid-term sales to Spain.

Oman added another train in 2006

Oman started exports in 2000 to mainly Korea and Japan on a long-term basis, as well as some mid-term sales to Spain from the two-train 9.8 bcm per year (7.2 mtpa) Oman LNG plant at Qalhat. Oman added another 4.9 bcm per year (3.6 mtpa) Qalhat LNG train in early 2006.

Yemen advancing toward 2009 start of production

Yemen LNG is on schedule for its targeted first production by the end of 2008, since a turnkey contract for EPC and start-up services was awarded in September 2005. The project will have two 4.6 bcm per year (3.4 mtpa) liquefaction trains in 2009. Of the country's 17 Tcf (481 bcm) proven gas reserves, 9 Tcf (255 bcm) is earmarked for the LNG project. About two-thirds of the LNG would go to North America and the remainder to Korea.

Iran: preliminary deals with Thailand and China

Thailand's state-owned PTT in summer 2006 provisionally contracted for 4.1 bcm per year (3 mtpa) from Iran's proposed Pars LNG project for 20 years beginning 2011. PTT plans to construct a receiving terminal on the country's eastern seaboard. China's PetroChina signed a heads of agreement in November for the supply of 4.1 bcm per year (3 mtpa) for 25 years. The Pars LNG venture includes France's Total, Malaysia's Petronas and the National Iranian Oil Co. (NIOC). The project partners may take a final investment decision to build the 13.6 bcm per year (10 mtpa) plant in 2007.

NIOC and China National Offshore Oil Corp. (CNOOC) in November 2006 signed a USD 16 billion deal to develop Iran's North Pars gas field and build LNG facilities. NIOC also inked major gasfield/LNG project agreements with relatively un-known players in LNG, with Australia's LNG Ltd for development of the Selkh and Southern Gesho fields for LNG export in November 2006 and with Malaysia's SKS Ventures for the Golshan and Ferdows offshore gasfields in January 2007. China National Petroleum Corp. (CNPC; PetroChina's parent company) is also reportedly finalising its memorandum of understanding with NIOC to jointly develop a USD 3.6 billion upstream and 6.1 bcm per year (4.5 mtpa) LNG project based on gas reserves of South Pars gas field in early 2007.

Despite those talks, NIOC has made no physical progress in LNG developments. In the meantime, Iran is struggling to cover both domestic demand and existing pipeline gas export obligations (see section on Iran).

Both new Egyptian exporting plants are considering expansions

The Damietta LNG plant, which started production from its first 6.8 bcm per year (5 mtpa) in late 2004, is likely to proceed to a second train of a similar capacity, with a recently signed framework agreement between the operating company Segas partners (Union Fenosa, Eni, Egyptian Gas Holding Co (EGAS), and Egyptian General Petroleum Corp (EGPC)) and BP. Production start is expected to be around 2010 - 11, although progress depends on the location of adequate reserves for the plant, in the light of the government's stricter requirements on gas for export use.

BG, one of the major partners and also long-term lifters in Egyptian LNG project at Idku, which started exporting LNG in early 2005 and currently has two 4.9 bcm per year (3.6 mtpa) trains, hopes to build a third liquefaction train at the plant, partly fed by gas from Palestinian-controlled Gaza Marine Field in the Mediterranean Sea, with targeted start up in 2010 - 11. This also depends on the success of exploration efforts.

Algeria: the Atlantic Basin's longest established and largest exporter

Algeria, which started exports back in 1964, has an installed production capacity of 27.2 bcm per year (20 mtpa) from 18 trains at Arzew and Skikda, excluding the three trains at the Skikda plant destroyed in the explosion in January 2004. The plants are operated by state owned Sonatrach. Spain's Repsol and Gas Natural along with Sonatrach's minority participation, plan to develop their brand-new El Andalus LNG based on gas reserves at Gassi Touil, with a 5.4 bcm per year (4 mtpa) liquefaction plant near Arzew, targeted for completion by November 2009. Sonatrach has a plan for a 5.4 bcm per year (4 mtpa) train at Skikda, replacing the destroyed ones. Both plans apparently have some engineering issues, possibly causing some delays, cost increases and modifications to the plans.

Libya: unlikely to expand soon

The Marsa el Brega LNG plant in Libya, one of the oldest (starting in 1970), owned by National Oil Corporation (NOC), used to have a nominal capacity of 3.1 bcm per year (2.3 mtpa), although recent exports have been significantly less than that. In fact, the country has not exported even at 50% of that rate since 1981. Due to high Btu content, all of the production is supplied to Spain's Barcelona terminal, where LPGs are stripped out and the heating value of the gas is reduced. Shell has been putting together plans to upgrade and potentially expand the aging facility since 2004 and submitted a "rejuvenation" plan in 2006.

West Africa's emergence as a major force

Equatorial Guinea LNG's steady progress and a likely expansion

The Marathon-led Equatorial Guinea LNG consortium, which also groups state-owned Sociedad Nacional de Gas (Sonagas GE), Mitsui and Marubeni of Japan, is constructing a 4.6 bcm per year (3.4 mtpa) liquefaction plant at its Bioko Island site with projected commencement in the middle of 2007. There is a slight concern about Marathon's Alba field, which can only support the project for 12.5 years. BG Group has purchased 4.6 bcm per year (3.4 mtpa) from the base project over 17 years from start up. The FOB contract will allow BG to direct cargoes anywhere in the world.

Plans of the project's second train of 6 bcm per year (4.4 mtpa) received a boost in December 2006 by a Heads of Agreement between Nigeria and Equatorial Guinea for gas supply from Nigerian National Petroleum Corp (NNPC). The gas is likely to be sourced from the Oso gas-condensate fields operated by a joint venture between NNPC and ExxonMobil in the Niger Delta. Cameroon also has some potential to supply feedgas to EGLNG from its substantial gas reserves within a 100 km radius of EGLNG. Sonagas signed an agreement to receive pipeline gas from Cameroon's state-owned National Co. of Hydrocarbons in January 2007. The EGLNG consortium has already started preliminary engineering works for the second train.

Nigeria's incremental plans (OKLNG, Brass, NLNGSevenPlus)

Work on the seventh and eighth trains of 10.9 bcm per year (8 mtpa) each at Nigeria LNG (NLNGSevenPlus) is slipping and startup will be likely to be delayed by one year to mid-2011 or later. A final investment decision on the new facilities has been postponed until the second quarter of 2007.

Brass LNG is also making progress to start production in 2011 or later, with Total replacing Chevron to join the project, which plans to have a capacity of 13.6 bcm per year (10 mtpa) from two trains. BG, BP, and Suez have already agreed to lift 2.7 bcm per year (2 mtpa) each from the project. The ownership of the project is not clear yet. At the time that Total succeeded Chevron, the shareholders were believed to be NNPC (49%), ConocoPhillips (17%), Eni (17%) and Total (17%). In September 2006, Nigeria unilaterally reduced the stakes of Total to 12.5% and ConocoPhillips to 16.5%, and planned to give Centrica 3% and BG 2%, but a final agreement has not been announced.

Olokola LNG (OKLNG), which groups NNPC, BG, Chevron and Shell, has reached several milestones in siting and engineering aspects for its two-train, 15 bcm per year (11 mtpa) project, which could be expanded to a four-train, 30 bcm per year (22 mtpa) at a later date. The target date for the production currently stands at 2011.

It should be noted the election year 2007 might affect the government's priority concerning new and expansion projects. Although production at Nigeria's existing LNG plant in Bonny Island has not been impacted by ongoing violence in that country so far, there is general concern about security issues among investors, including LNG developers.

Russia's ambitious move into the global LNG market

Participation in Sakhalin

Construction works at the planned Sakhalin II liquefaction plant in the Russian Pacific island of Sakhalin are on schedule to complete the

Table 12	Sakhalin I & II projects	
Sakhalin I ExxonMobil, Sodeco (Japan), ONGC (India), Rosneft-Sakhalinmorneftegas	8 bcm per year piped gas or LNG Piped gas to China; LNG call is made from India and Japan	
Sakhalin II Gazprom, Shell, Mitsui, Mitsubishi	13.1 bcm per year (9.6 mtpa) of LNG planned volumes have been sold on long-term basis to Asia and West Coast North America	50% + 1 share transferred to Gazprom

Source: Company announcements.

first 6.5 bcm per year (4.8 mtpa) train in 2007 and the second train of the same capacity within six months after that. Since pipeline supply of feedgas is not expected until 2008 because of upstream development delays, plans are to commission the trains by importing LNG, regasifying it and then reliquefying the gas. The project has estimated gas reserves of 500 bcm. Japanese customers have an advantage in saving on transportation costs by being relatively close to the exporting project.

The Sakhalin I and II ventures were "grandfathered" in the Gazprom's monopoly over gas export that Russia's legislature 'Duma' confirmed in July 2006. Faced with growing pressure from the state's environmental agency Shell and its partners in Sakhalin Energy Investment Co. (SEIC), Mitsui and Mitsubishi of Japan, agreed in December 2006 to hand over a controlling 50%-plus-one-share stake in the export venture to the Russian giant for USD 7.45 billion in cash payment. The Sakhalin II and the country's two other production sharing agreements (PSAs) were signed in the mid-1990s when the country was in some financial distress and have been seen by many Russians as unfairly advantageous to foreign shareholders.

Gazprom was already negotiating for participation in the project when Shell announced the project's cost doubling to USD 20 billion in July 2005. The figure had grown to USD 22 billion by December 2006. Under the previous negotiation before the cost increase announcement, Gazprom was set to get a 25% stake in SEIC from Shell in exchange for a 50% interest in deeper layers of the giant Zapolyarnoye field in Siberia. But the massive cost increase, which meant reduced and delayed revenues for Russians, halted the negotiations and angered Russian officials. Under the terms of the PSA, the shareholders would be allowed to recover investment costs from gas sales before the allocation of profits, taxes and royalties to the government.

After the share transfer agreement, Gazprom confirmed that all the supply commitments from the project would be met on time, starting in late 2008. It also indicated the possibility of expansions, potentially using resources from other deposits in the region. This could include the Sakhalin I gas, although the project operator ExxonMobil says it has agreed to sell the gas to China via pipeline.

Gazprom is establishing agreements with major LNG suppliers and buyers in the world, following the Russian giant's commencement of LNG trading in the

Table 13 Gazprom's spot LNG deals

	Deal	Notes
September 2005	First Sale to the United States	Sold to Shell at Cove Point, Maryland
November 2005	Gaz de France swap	Sold to Shell at Cove Point, Maryland
Spring 2006 - 2007	BP Sale to Gazprom	4 cargoes to the United States and the United Kingdom
August 2006	Sale to Japan	An Oman cargo via Celt (Tepco)
September 2006	One of BP sales	Sold to Shell at Cove Point, Maryland
October 2006	Sale to Korea	An Oman cargo via Celt to Pyeongtaek

Source: Company announcements.

Atlantic Basin in September 2005. In August 2006 the company signed a master trading agreement with Japan's Tepco, which resulted in a cargo purchase from Tepco's and Mitsubishi's joint venture Celt and resale to Chubu Electric. In October 2006, Gazprom signed a master trading agreement with Korea Gas (Kogas).

Baltic, Shtokman, and Yamal LNG projects

The Baltic LNG project, which is supposed to have a capacity of 7.2 bcm per year (5.3 mtpa) at a site near St. Petersburg by around 2010, could be the company's own first LNG export venture in the Atlantic Basin. Gazprom invited Sonatrach of Algeria to participate in the project in January 2007. The giant Shtokman project in the Barents Sea, for which Western partners for LNG development were expected to be announced around the time of the G-8 Summit in St. Petersburg in July 2006, is now more likely to supply gas to Europe via pipeline, after Gazprom announced in October 2006 that it would proceed with Shtokman on its own rather than giving 49% of the project to foreign players. There may be another export project on Yamal Peninsula, but this reserve is also likely to be developed on the basis of pipeline sales.

Norway Snøhvit: Europe's and the Arctic's first LNG export project

Norway's Snøhvit LNG project's target dates for first gas from the project's offshore fields are mid 2007, in time for initial production of LNG by the plant in August, with first shipments in September or October. Regular commercial exports from the 5.6 bcm per year (4.1 mtpa) facility look set to start December 2007. The first LNG exporting plant in Europe and in the Arctic Circle imported an LNG cargo at the beginning of 2007 to cool down the loading and storage systems and to fuel its utilities until its own offshore feed gas comes in the summer. This project is very novel, and has faced many technical challenges, and encountered considerable delays.

Trinidad: the largest exporter in the Americas

The Atlantic LNG plant in Trinidad and Tobago is the largest export facility in the Americas. Its geographical position guarantees it numerous long-term outlets in North America. Its share in the United States' and Puerto Rico's LNG markets in 2006 was 68%. The plant's first train at Point Fortin, on the southwest coast of Trinidad, was only the second grassroots LNG exporting facility in the Americas when it started operations in 1999, following Alaska's Kenai plant in 1969. The second and third trains were commissioned in 2002 and 2003, followed by the fourth in 2005, resulting in the current total exporting capacity of 20.6 bcm per year (15.1 mtpa). While a fifth production train ("Train X") has been mooted for some time, the development structure for the project has not been firmed up yet. The government said in January 2007 that it had commissioned a feasibility study to assess gas supply for a fifth train.

Venezuela: still far from exporting

After talk of exporting LNG for more than 15 years, Venezuela has not seen much progress in its LNG projects. Gas fields in the Norte de Paria area, which were once viewed as feedgas sources for Mariscal Sucre LNG project, are now to be developed to supply the domestic market. Gas in the Plataforma Deltana area could be used as sources for an LNG project. There is a possibility that the gas could be processed at Trinidad's Point Fortin plant, if talks between the two countries advance in that direction.

Peru LNG: first in Pacific South America

The Peru LNG consortium, comprising Hunt Oil of the United States (50%), SK of Korea (30%) and Repsol YPF of Spain (20%), plans to build a liquefaction plant on Peru's southern coast, which will produce 6 bcm per year (4.4 mtpa) of LNG to be exported to Pacific North America, and possibly Chile. Feed gas will come from the Camisea fields in the southeastern rain forest. Chicago Bridge & Iron won the engineering, procurement and construction (EPC) contract valued at USD 1.5 billion for the liquefaction plant in January 2007. The project is expected to be completed in first half of 2010. The project represents the first in Pacific South America.

Consuming country developments

Consolidation of LNG terminals plans in North America

In autumn 2006 and early 2007, three import terminal plans were shelved by major oil companies (BP's Bay Crossing, ExxonMobil's Vista del Sol, and ConocoPhillips' Beacon Port) and two others were delayed (Sempra's Port Arthur and Occidental's Ingleside Energy Center), all in the Gulf of Mexico area in the United States. Possible reasons include an expected glut in terminal capacity in the area, and more importantly, shortage of long-term supply sources. Further consolidation is likely since five terminals with a total capacity of 110 bcm per year are currently approved for construction, several more projects of 100 bcm per year are under regulatory review and another some 45 bcm per year is under consideration. Terminals already available and under construction in North America have a capacity of 160 bcm per year, approaching 20% of North American gas demand in 2010.

North American marketers will deliver to these receiving terminals if the price is right, but are not subject to binding commitments to do so. Therefore, if they can sell gas at a premium elsewhere, these terminals are likely to be underused. Similarly, if the North American market is attractive, it will attract more gas from other markets.

Table 14 **North American LNG receiving terminals already available & under construction**

Terminal	Location	Capacity (bcm per year)	Start
Operating			
Atlantic			
Everett	Massachusetts	8.3	1971
Cove Point	Maryland	10.3	1978
Elba Island	Georgia	15.5	1978
Gulf of Mexico			
Lake Charles	Louisiana	19.1	1982
Gulf Gateway	Offshore Louisiana	4.9	2005
Mexico			
Altamira	Tamaulipas, Mexico	5.2	2006
Sub total		**63.3**	
Under Construction			
East Coast			
Cove Point expansion	Maryland	8.3	2008
Gulf of Mexico			
Cameron	Louisiana	15.5	2008
Freeport	Texas	15.5	2008
Sabine Pass	Louisiana	41.4	2008
Golden Pass	Texas	20.7	2009
Canada			
Canaport	New Brunswick	10.3	2008
Pacific			
Costa Azul	Baja California, Mexico	10.3	2008
Sub total		**122.0**	
Total		**185.3**	

Source: IEA data.
Note: Sabine Pass includes a 14.5 bcm per year expansion in 2009; Puerto Rico has an LNG receiving terminal that is not included in this table.

Some diversion of long-term volumes from the United States to Asia

Qatari LNG marketers are executing some flexibility in diverting cargoes from three mega trains of 10.6 bcm per year (7.8 mtpa) each under construction in Qatar, originally designated for the planned Golden Pass terminal in Texas, sponsored by Qatar Petroleum (QP) itself along with ExxonMobil and ConocoPhillips. Substantial output from the huge production facilities in Qatar is now likely to go to Asia on a long-term basis, once negotiations between Qatar and Asian buyers are concluded. Some volumes originally contracted for terminals in the Pacific North America could also go to Asia later in the decade.

Mexico receiving first cargoes at the Altamira terminal in the Gulf of Mexico

The Altamira terminal on Mexico's Gulf Coast successfully received the country's inaugural LNG cargo from Nigeria in the middle of August 2006. The commercial operation of the terminal began in October, selling regasified gas to state power generator (CFE). LNG is needed to supplement indigenous gas production and reduce dependence on piped gas from the United States. This would free up some supply around the borders of the two countries. The terminal's initial capacity equates to around one tenth of the country's average gas demand. Another receiving terminal, Energia Costa Azul, is being constructed in Baja California on the Pacific coast, and is due to start operations in 2008. The state power generator is conducting bids for another LNG project on the West coast, Manzanillo, which has suffered repeated delays due to lack of available long-term supply. The terminal is not likely to be operational before 2012.

United Kingdom: higher LNG terminal utilisation

In 2006, the Isle of Grain, the only currently operating onshore LNG receiving terminal in the United Kingdom, received 45 cargoes,

Table 15 LNG terminals in the United Kingdom

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Isle of Grain	National Grid	Operating	4.9	2005
Teesside	Excelerate Energy	Operating	4.0	2007
South Hook I	Qatar Petroleum / ExxonMobil	Construction	10.6	Late 2007 or early 2008
Dragon LNG	BG, Petronas, 4Gas	Construction	6.0	2008
Isle of Grain expansion	National Grid	Construction	8.7	2008
South Hook II	Qatar Petroleum / ExxonMobil	Construction	10.6	2009
Potential total			**44.8**	

Source: *Natural Gas Information 2006*, IEA and company information.

after opening in July 2005, receiving only seven in that year. Despite the market softness, importers into the terminal have been constantly filling their allocated slots with cargoes and are expected to do so through the winter of 2007, partly because of the perceived "use-it-or-lose-it" rule on terminal capacities. Utilisation of the Teesside dockside LNG terminal, which was developed by the United States' Excelerate Energy and started operations in February (only ten months after the project was announced in April 2006), is likely to depend purely on prevailing prices in the United Kingdom and other markets, as this terminal is designed to meet winter peak usage (up to 11 mcm per day). Cargoes reserved for this terminal could be easily diverted to the other terminal of the same operator in the United States' Gulf of Mexico or sold to other higher paying customers.

Likely tentative diversion of LNG to Asian markets from the United Kingdom

Due to the low prices in the United Kingdom's market due to increased pipeline supplies from Norway, Qatari LNG marketers, who have two 10.6 bcm per year (7.8 mtpa) liquefaction trains primarily targeting the United Kingdom markets, may not place all the large volumes from these mega facilities into the United Kingdom for several years from 2008. Tentative diversions to the Asian market in the period are likely. In the longer term (after 2011 - 2012), however, the United Kingdom market is viewed as very attractive, given the decline in the country's gas production, and competition from continental Europe for North Sea gas.

Belgium: expanding LNG terminal and third-party access

Belgium has an LNG receiving terminal at Zeebrugge, built in 1987. Suez's Distrigaz subsidiary owned 100% of the capacity until 2006. As expanded capacity comes online in the second quarter 2007, the number of capacity holders at the 9 bcm per year terminal rises to three: Distrigas (2.7 bcm per year for 20 years), a joint venture between Qatar Petroleum (QP) and Exxon Mobil (4.5 bcm per year for 20 years) and Suez (1.8 bcm per year for 15 years). To facilitate European Commission approval of their proposed merger, Gaz de France and Suez in September 2006 proposed creating new gas competitors in France and Belgium. The companies would set up three structures in Belgium out of Fluxys, another Suez company. Through one of them, Fluxys International, the

Table 16 LNG terminals in Belgium

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Zeebrugge	Fluxys	Operating	4.5	1987
Zeebrugge expansion I	Fluxys	Construction	4.5	2007
Zeebrugge expansion II	Fluxys	Proposed	9.0	2011
Potential total			**18.0**	

Source: *Natural Gas Information 2006,* IEA and company information.

Table 17 LNG terminals in France

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Fos-sur-Mer	Gaz de France (GdF)	Operating	7	1972
Montoir de Bretagne	Gaz de France (GdF)	Operating	10	1982
Fos Cavaou	GdF, Total	Construction	8.25	2nd Half 2007
Montoir expansion	Gaz de France (GdF)	Open Season	2.5-6.5	2011, 2014
Bordeaux (Le Verdon)	4Gas	Proposed	6-18	2011
Antifer (Le Havre)	Poweo, CIM	Proposed	8-15	2011
Dunkirk	EdF	Proposed	6-12	2011
Bordeaux (Le Verdon)	Endesa	Proposed	4-8	
Potential total			**52-85**	

Source: *Natural Gas Information 2006*, IEA and company information.

merged group would retain the effective ownership of the Zeebrugge terminal. Fluxys says it will facilitate secondary capacity rights trading at the terminal.

New and expansion plans advancing in the Netherlands, Spain, Italy and United Kingdom

Four LNG terminals are being planned in the Netherlands. Two import projects proposed for Rotterdam in the Netherlands are making progress, with LionGas (9 bcm per year in 2009) receiving a positive response to its environmental impact statement from government regulators and the Gas Access to Europe (Gate) project (8 - 12 bcm per year in 2010) securing customers for 5 bcm per year of access at the terminal. Taqa - the national energy company of Abu Dhabi, the United Arab Emirates - announced in February 2007 that it is going to build an LNG installation off the coast near Rotterdam, utilising onboard regasification technology and offshore depleted gas fields for gas

Table 18 LNG terminals in the Netherlands

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Rotterdam (Gate)	Gas Transport Services, Vopak	Proposed	8	2010
Rotterdam (LionGas)	4Gas	Proposed	9	2010
Rotterdam (offshore)	Taqa	Proposed		?
Eemshaven	ConocoPhillips, Essent	Proposed	5	2011
Potential total			**22.0**	

Source: Natural Gas Information 2006, IEA and company information.

Table 19 LNG terminals in Spain

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Barcelona	Enagas	Operating	17.3	1969
Huelva	Enagas	Operating	13.6	1988
Cartagena	Enagas	Operating	9.9	1989
Bilbao	Bahia de Bizcahia*	Operating	8.0	2003
Sagunto	Saggas**	Operating	6.0	2006
Mugardos (El Ferrol)	Reganosa Group***	Construction	3.6	2007
Sagunto expansion	Saggas	Proposed	2.0	2008
El Musel	Enagas	Proposed	7.0	2011
Bilbao expansion	Bahia de Bizcahia	Proposed	2.5	-
Potential total			**69.9**	

*BP, Repsol, Iberdorola, EVE.
**Endesa, Iberdrola and Union Fenosa Gas along with the Oman government.
*** Endesa, Union Fenosa Gas, Galicia's Tojeiro group, Algeria's Sonatrach, the Galician government, Caixa Galicia, Banco Pastor and Caixanova.
Source: *Natural Gas Information 2006*, IEA and company information.

Table 20 LNG terminals in Italy

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Panigaglia	GNL Italia (Snam)	Operating	3.5	1969
Rovigno offshore	Qatar Petroleum, ExxonMobil, Edison	Construction	8.0	2008
Livorno offshore	Endesa, Amga, Belleli	Construction	3.0	2009
Brindisi	BG Group	Site preparation suspended	8.0	2010
Potential total			**22.5**	

Source: *Natural Gas Information 2006*, IEA, company information.

storage. ConocoPhillips and Essent Energie are planning their terminal at the Port of Eemshaven in the North Groningen.

Italy, which has one operating terminal Panigaglia, has several LNG terminal plans under regulatory review, some of which (Livorno, Brindisi and Rovigo) have already been granted some approvals. In the United Kingdom, in addition several expansion phases at the operating Isle of Grain terminal and two land-based projects in Milford Haven in Wales, the United States' Excelerate Energy Teesside terminal in northern England entered service early in 2007.

In total, these plans, in France, as well as those in Italy, Spain, United Kingdom, Netherlands (Rotterdam in the south, and Eemshaven in the north), and Germany, indicate that companies expect healthy demand growth and prices stable and high enough to justify their LNG import plans. Interest in using terminals is strong, including cross-border flows from the terminals (*e.g.* EdF's capacity commitment for 3 bcm per year at the Gasunie-Vopak Gate terminal in Rotterdam).

Japan fuel switching and nuclear problems boost gas demand

Japan is currently the largest importer of LNG in the world and is expected to be for several years to come. The country has 28 LNG receiving terminals nominally capable of regasifying 230 bcm per year (170 mtpa) of LNG, used by 17 companies. Fuel switching in the industrial sector (a +13% gas demand increase in 2006) and nuclear problems supported an increase in LNG imports in 2006 (+7%, or +5.4 bcm (4 million tonnes) to 86 bcm (62 million tonnes) in total). Another notable point in the year was increasing imports from the Atlantic Basin, which represented a third of the year's incremental imports, compared to no spot cargoes from the Atlantic in 2005.

Korea's demand up in the first half, down in the second 2006

Gas sales by Korea Gas Corporation (Kogas), the state-controlled gas importer, rose 3% to 32 bcm (23.5 million tonnes) in 2006 from 31.2 bcm (22.9 million tonnes) in 2005. While in the first half of the year, demand surged by 10%, as rising oil prices led power generators to burn more gas, in the latter half the sales declined by 5% on year-on-year basis due to the milder weather.

Over the next decade, the government projects that gas demand will grow by about 5% annually, to over 41 bcm per year (30 mtpa) by 2017.

In addition to the high demand growth, the seasonal difference of consumption is another important issue. Winter peaks are 2.5 - 3 times as big as summer lows. In order to handle seasonal fluctuations, the company plans to increase LNG storage capacity from current 4 880 000 m^3 to 8 240 000 m^3 (+69%) by 2013. Kogas has also signed an initial agreement with Oman's state gas company to build and operate two 200 000 m^3 tanks in the sultanate. Kogas has also talked with the sponsors of an LNG storage hub project in Dubai. While Kogas has some winter-weighted contracts, storage continues to be the key.

Chinese Taipei's second terminal is under construction

Chinese Taipei's CPC Corporation started importing LNG at Yung An terminal in the southern part of the island in 1990. The island's LNG import growth was 8.4% in 2006 with an import total of 10.5 bcm (7.7 million tonnes), compared with an average 10.0% growth a year experienced since 2001, due to the slow down of deliveries from Indonesia. The loss was 0.5 bcm (0.4 million tonnes) in 2006 in total, or 11% of the contracted volumes. CPC currently buys LNG from Indonesia and Malaysia under long-term contracts. The company also has a long-term contract with Qatar's RasGas for 4.5 bcm per year

(3.3 mtpa) from 2008, with 2.3 bcm per year (1.68 mtpa) dedicated to the 4.27 GW Tatan power plant. The gas would be supplied through CPC's Taichung terminal under construction in the central part of the island, targeted for completion in 2009.

China rationalizes its numerous LNG receiving plans

China's first LNG receiving terminal in Guangdong started to import cargoes in May 2006. The operator of the terminal, state-controlled CNOOC, is developing a second receiving terminal in Fujian and is now forging ahead with a third facility at Shanghai (with Shanghai utility company, Shenergy, holding the controlling stake). Construction officially started in January 2007. This may be the last receiving terminal to be built by the end of this decade in the country. Although some progress is seen in projects in Hong Kong, Zhejiang, Liaoning, and Hebei, new LNG supplies are now likely to be post 2012. The number of realistic receiving terminal plans has dwindled after its proliferation to nearly twenty in early 2005, due to high global gas prices causing a return to coal for power generation. Total import capacity could be 15 - 20 bcm per year in 2010.

India devising ways to increase LNG supply

Petronet, India's first and largest LNG importer, buys 6.8 bcm per year (5 mtpa) under a long-term contract from Qatar's RasGas for its Dahej terminal in the western state of Gujarat, which started importing LNG in 2004. The quantity will increase to 10.2 bcm per year (7.5 mtpa) in 2009. Petronet plans another terminal in Kochi in the state of Kerala, which targets an initial capacity of 3.4 bcm per year (2.5 mtpa) in 2010, eventually expandable to 6.8 bcm per year (5 mtpa). Petronet is also expanding capacity at the Dahej terminal from current 8.8 bcm per year (6.5 mtpa) to 17 bcm per year (12.5 mtpa) by December 2008.

The company says it hopes to sign a purchase agreement for 3.4 bcm per year (2.5 mtpa) from ExxonMobil's share of LNG from Australia's Gorgon project by June 2007. It secured recently another 2 bcm per year (1.5 mtpa) of LNG supply under medium-term contracts from Algeria, Malaysia and BG. Those supplies are sold to the Dabhol power plant in the western state of Maharashtra. The regasified LNG will be transported through a Dahej-Dabhol pipeline, to be completed in 2007. The 6.8 bcm per year (5 mtpa) Dabhol LNG import terminal will be a source of gas from early 2009.

Petronet is also talking with Shell to buy 1.4 bcm per year (1 mtpa or 16 cargoes per year) for import through the 3.4 bcm per year (2.5 mtpa) Hazira terminal, also on India's west coast, which is owned by Shell (74%) and Total (26%) and operated solely with spot cargoes. Petronet intends to pay tolling charges to bring cargoes in through Hazira, and to sell them to the Dabhol power plant as well.

The two Indian terminals received 8.4 bcm (6.2 million tonnes) of LNG in total in 2006.

Singapore, Thailand, Chile, and Brazil may advance LNG receiving initiatives

Singapore decided to go ahead with its plan of 4.1 bcm per year (3 mtpa) LNG terminal plan in early August 2006, citing "security of gas supply" as the main driver. Thailand's state-owned PTT confirmed a plan to construct a receiving terminal on the east coast of the country by 2011, signing up Iranian supply.

Chile has multiple plans to import LNG into its central and northern regions to reduce dependence on piped imports from Argentina.

Brazil's state-owned Petrobras is developing two dockside regasification import terminals in the north and south of the country with urgent priority, endorsed by the country's national energy policy council. The company is initially seeking up to 2 bcm per year (1.5 mtpa) at Pecem in the north and 4.8 bcm per year (3.5 mtpa) for Guanabara Bay in the south near Rio de Janeiro by as early as July 2008. Supply for these terminals will not be easy to procure. The company is also considering building a third terminal.

Tight engineering market may cause delays and project cost increases

Global shortages of skilled labour forces and contractors with expertise, especially in the LNG sector which requires special technology and engineering, have caused delays and cost increases in the sector. The increasing cost of new materials has also meant delays to projects. The impact is greater as projects are planned on mega scales these days, even though unit costs can be lowered with larger facilities. Modular construction practices may become more popular to alleviate constraints in project development. While these problems are found throughout the energy sector, they are especially acute for LNG production and import facilities. This is discussed further in the Investment section.

Possible shipping constraints: crewing

The LNG shipping industry is experiencing an unprecedented fleet expansion. A record 35 ships are scheduled to be delivered in 2007, adding to the current 220 carriers. Another 47 ships are expected in 2008. The global fleet will be over 350 vessels by 2010 and is widely expected to approach 400 by 2015. Another thing to be noted is expansion of capacity of newly built ships. The average capacity of a new ship delivered from yards will grow from 140 000 m^3 in 2005 to 180 000 m^3 in 2008.

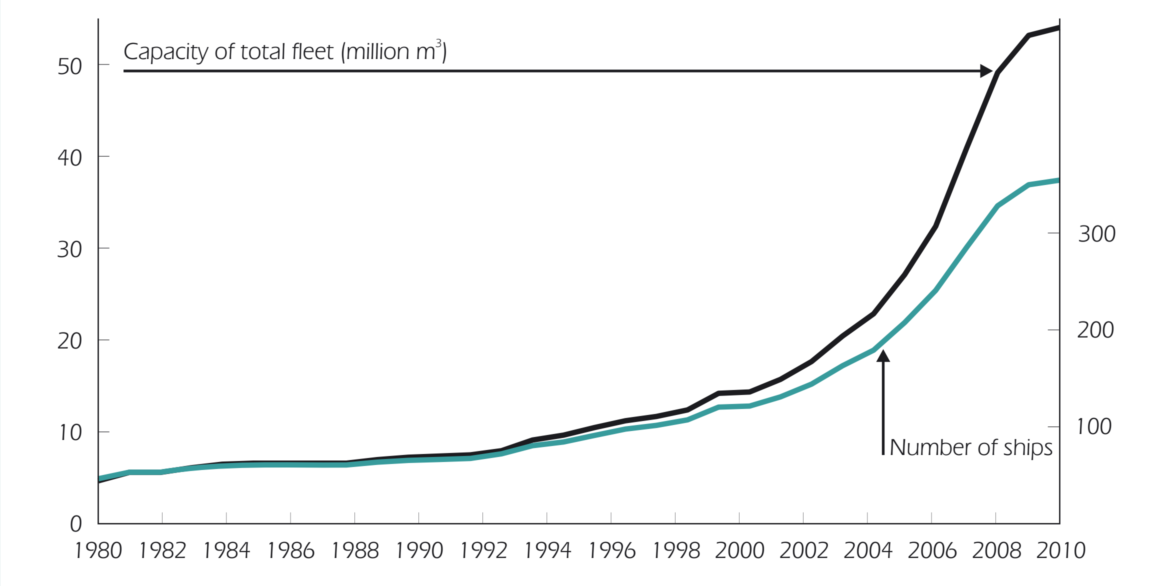
Naturally, crewing requirements have been increasing and have reached levels never seen in the LNG industry. A typical LNG vessel needs a complement of 27 seafarers comprising five deck officers, five engineer officers and 17 crew members. Taking into account vacations, illness and turnover, the total requirement is 64 to 70 seafarers for each vessel. This means the additional 130 ships need 9 000 seafarers in 2010, including nearly 3 000 qualified officers.

New trends of onboard regasification

LNG onboard regasification technology has recently become popular around the world, due to its quicker implementation schedule than conventional land-based LNG receiving terminals, especially after successful examples have been shown by Excelerate Energy in summer 2005 with its first offshore buoy and turret system in the United States' Gulf of Mexico, and in February 2007 with its first dockside regasification project in northeast England.

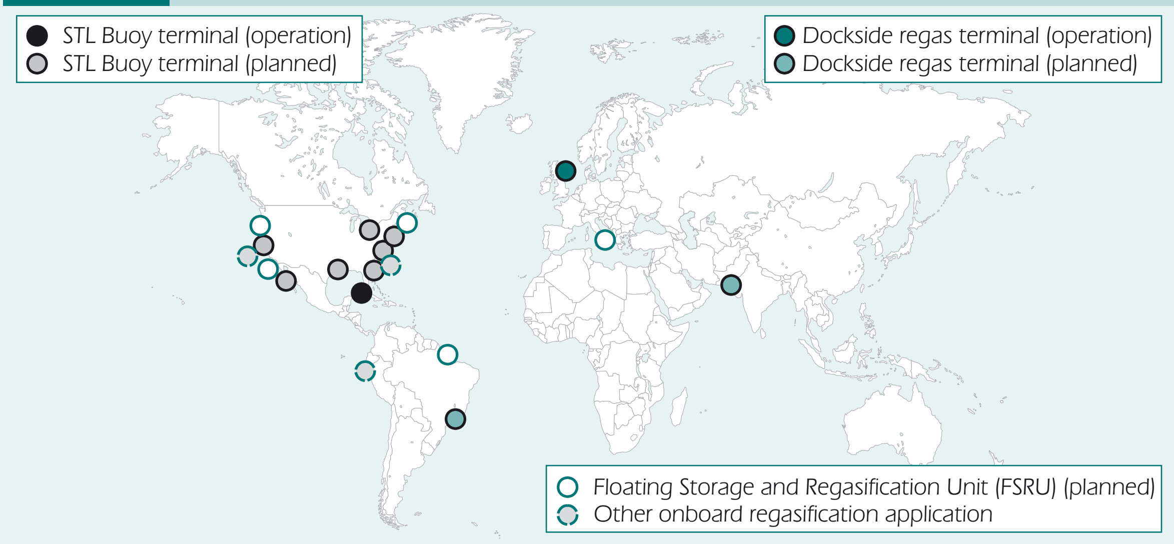
There could be at least a few more terminals with onboard regasification technology in coming years out of twenty planned projects. To date, there are three operating LNG regasification vessels (LNGRVs) and six more of these specially-

Figure 25 **An unprecedented fleet expansion**



Source: Company announcements.

Figure 26 **Import terminals using onboard regasification technology**



Note: STL = submerged turret buoy.
Source: Company announcements, media reports.

equipped ships are on order and more are on the way. Excelerate Energy and its shipping partner Exmar dominate orders. Golar LNG is adding onboard regasification on two of its vessels to convert them into floating storage and regasification units (FSRUs). Several purpose-built FSRUs are also planned.

Marketing, contracts and spot trade evolution

Stable and relatively lower long-term LNG prices, consistently lower than oil

Japanese average LNG import prices have been lower per unit of energy than those of crude oil for more than three years. The gap looks to be increasing for the moment. Historically LNG prices were more expensive than oil, so many industrial customers have not seen the price incentive to change fuel. However, due to the LNG's linkage to oil of around 85% or less, the current expensive oil prices do not make LNG prices increase in the same manner.

This current trend creates several notable changes both internally and externally: an accelerated shift to natural gas in industrial energy use (*e.g.* a 13% year-on-year growth in industrial sector gas sales in 2006 in Japan); exceptionally expensive spot LNG purchases to cope with the increased demand, which is managed by those LNG buyers with purchase portfolios large enough to absorb the high price; and sellers' arguments for price increases, especially in higher oil price ranges. More recently, even Indian LNG importers paid expensive spot prices in the face of even higher prices of naphtha in the country.

In terms of LNG pricing in Japan, and in most of Asia, both buyers and sellers have agreed, and still continue to agree, to base the price of LNG on oil. In traditional contracts concluded before 2002, the rates of gas price increase and decrease with oil are slowed by half outside of a certain oil price range so that buyers and sellers are protected from exceptional oil price environments both at high and low forces. This arrangement is called the "S curve" from the shape of the oil/LNG price graph. Over time the 'slopes' or rate of change of parts of this curve have changed, but the basic pattern remained until recently.

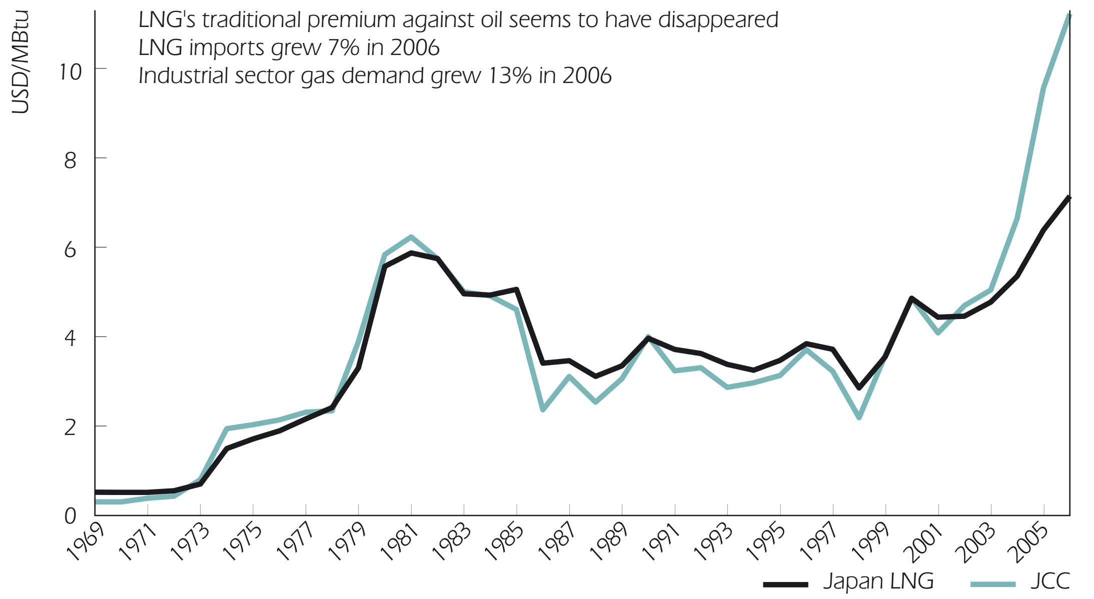
From 2002 to 2004 the basic slopes were lowered to ease linkages to oil and make LNG more competitive. Flat pricing, or floors and ceilings for higher and lower oil price ranges were also introduced into some contracts during those years.

However, after the surge in oil prices since 2005, pricing in this unprecedented oil price range has become the main issue, as such high oil prices was not originally taken into account in the traditional pricing formulas. Sellers are generally on steeper slopes to fill the gap.

More tenders for long-term volumes

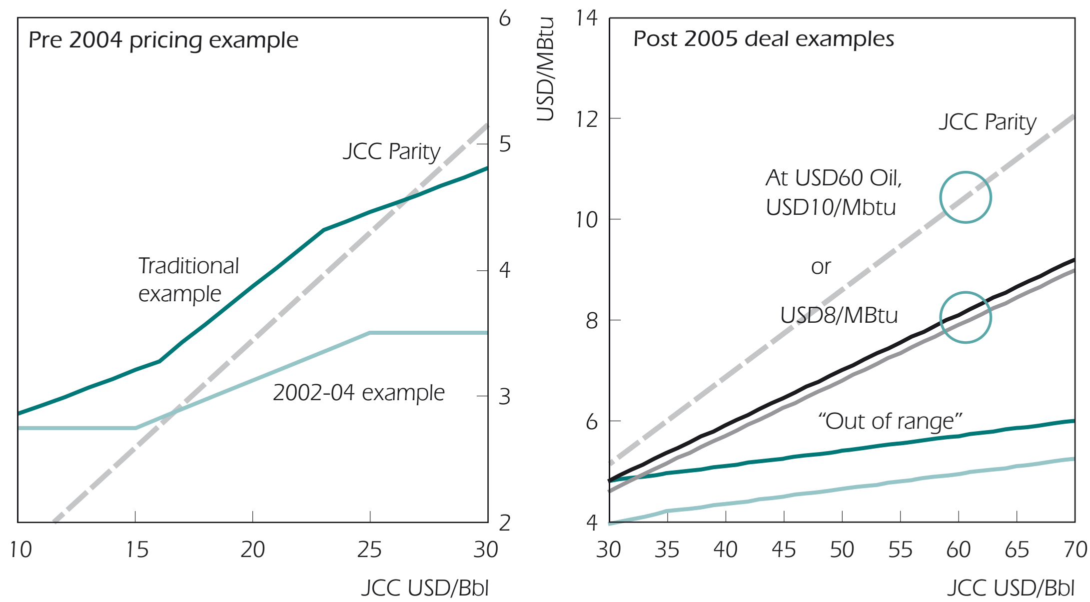
During the first half of this decade, tenders were successfully used by buyers in China, Korea, and Chinese Taipei for their long-term LNG purchases, resulting in generally

Figure 27 **LNG and oil prices in Japan since 1969**



Note: Japan's fiscal year: April to March. For 2006, the figure is for April to December
Source: Japan's import statistics.

Figure 28 **Changing focus on price negotiations**



Source: Media reports.

favorable pricing arrangements for those buyers. More recently, a similar approach is being adopted by sellers.

In 2006, the North West Shelf (NWS) LNG venture in Australia, at its renewal contract negotiations for volumes from 2009 with some of its long-term buyers in Japan, invited them to submit requests for volumes of LNG. The process apparently resulted in increased prices, shorter duration and reduced volumes. Arguably the shorter contracts can be seen as favorable to buyers, too, because they do not want to be bound in the longer term by conditions that do not reflect market realities.

Nigeria LNG (NLNG) allocated the expected output from its planned 7th train ("SevenPlus" project) between the five selected bidders, reportedly based on a sliding scale with the highest bidding companies getting proportionately more volume. The venture's aggressive asking pricing was a straight-line 90% of Henry Hub. The supplier can redirect cargoes into alternative destinations if the Henry Hub gas prices fall below a certain trigger point, by paying some compensation to the buyer.

Nigerian National Petroleum Corporation (NNPC) is conducting a tender process for its equity volume of 4.9 bcm per year (3.6 mtpa) in OKLNG project in the first quarter of 2007. There is some evidence that potential buyers had to bid at least 90% of Henry Hub on an ex-ship basis. Four or five buyers are expected to be chosen later this year.

Prices for the grassroots Brass LNG that were negotiated in 2005 and 2006 also came in between 88.5% and 90% of Henry Hub, depending on specific contracts. Some of the deals are structured so that different percentages apply above and below certain trigger points.

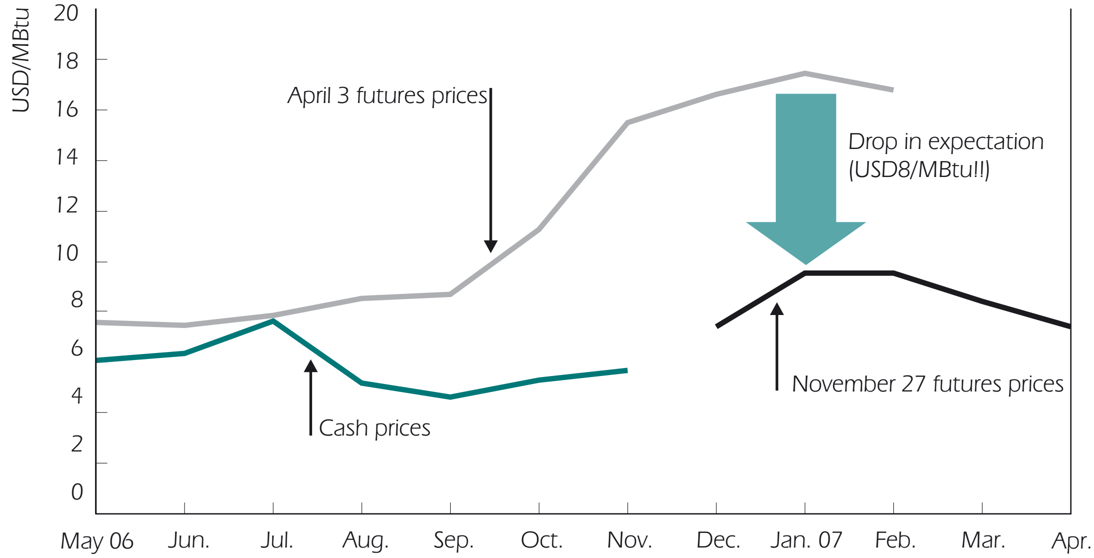
These followed earlier marketing activities in the decade targeting the United States' markets by NLNG Plus (Trains 4, 5 and 6) and Yemen LNG, which were settled at 84% - 85% of Henry Hub in 2003 - 2005. An even earlier deal negotiated by Equatorial Guinea LNG in 2003 has a percentage which varies according to gas prices and is below 84%.

New, more flexible marketing arrangements

Traditional LNG projects were underpinned by long-term sale and purchase contracts with consuming markets. However, more recent projects have been sanctioned with upstream stakeholders purchasing planned output, and in turn marketing by themselves, either through capacity and/or equity acquisition at regasification terminals in consuming countries, or even direct sales to willing buyers. Those companies with regasification capacities in multiple consuming regions are also making f.o.b. offtake commitments to fill those capacities or to sell to higher paying markets in a more flexible approach than previously seen.

Those projects where offtake arrangements are made in such a manner include the above-mentioned African projects, as well as projects in Trinidad and Tobago and Egypt. The strategy of directing output to more favorable markets is pursued in different ways also in the Pacific region.

Figure 29 **Big drop in price expectations: NBP (National Balancing Point) in the United Kingdom**



Source: IEA data.

Partners in the Australia's Gorgon projects are marketing their equity volumes separately, rather than collectively as one project. The North West Shelf (NWS) venture has avoided fully allocating volumes from Trains 1 - 3 after the existing contract expires in 2009, leaving some flexibility volumes in its own hands (2 - 2.7 bcm per year (1.5 - 2 mtpa)). The venture's operator, Woodside Petroleum, is also reserving one-third of its planned Pluto output for its own flexible marketing.

These flexible deals at loading points will lead to more "spot" LNG at receiving terminals, and more "globalisation" of the industry.

Diversion of cargoes from one region to another

For the first time in the history, as much as 6% of the Atlantic region's LNG production, 4.8 bcm or 3.5 million tonnes, was diverted into the Asian market in 2006. This trend does not seem to be a temporary phenomenon. Some medium-term and long-term deals have been signed to sell LNG into Asian markets, which were originally assigned to Atlantic markets on a long-term basis.

Pricing outlook

As demand continues to rise and new liquefaction plants are more expensive to build, and often run over budget and schedule, the LNG market looks set to remain tight in coming years. However, long-term pricing may not continue rising trends if more supply emerges around the turn of the decade. To the extent they can, buyers are likely to resist long-term commitments at higher prices. As geographically flexible and uncommitted LNG exporting capacity expands and unprecedented number of ships are delivered, short-term cargoes will increase, with pricing increasingly decoupled from that of long-term transactions and increasingly on a global basis.

"Future" prices sometimes create interesting developments

Besides long-term pricing, spot and future prices have a strong influence on actual cargo movements. One example is so-called "floating storage". While this method was once used as an emergency back-up measure, for example by Spain in winter 2005/06, it was also used by some companies who have spare shipping capacity to capitalize on much higher winter price expectation in the summer of 2006, fresh from memories of tighter gas markets in the previous winter. Some cargoes were kept floating as long as five months. In the end, the price expectations did not materialize by the start of winter 2006/07 (Figure 29).

Peak demand, LNG terminal utilisation and seasonal storage issues

LNG terminal usage patterns differ by region, reflecting the structure of LNG demand in various regions. In the Pacific Asia, where LNG is generally used as a base gas source without large underground gas storage capacity, seasonal demand fluctuations are absorbed by redundancy in LNG terminal capacities. In Europe, where large quantities of gas can be held in the system including more underground gas storage facilities, LNG terminals can enjoy higher utilisation rates. In the United States, where LNG still plays a marginal role and LNG deliveries vary depending on price differences with other markets, utilisation of regasification is rather low, and the need for LNG terminal storage capacity is not high thanks to huge networks of pipelines and underground gas storage facilities.

Coping with Indonesian shortfalls

Indonesia, which enjoyed its status as the world largest LNG exporter for 22 years lost the status to Qatar in 2006. It has in recent years been cutting its contractual LNG deliveries because of a slower-than-expected rate of gas reserves replacement as well as dwindling feed gas production. The reserve decline is most prevalent in the East Kalimantan fields that supply the Bontang liquefaction plant.

Table 21 LNG terminal regasification/storage capacity utilisation (2005)

	Imports/Regasification capacity	Storage capacity/Imports (days)
Pacific Asia	35%	36
Europe	61%	14
Atlantic America	36%	19
Worldwide	**40%**	**29**

Source: IEA data.

Total is the only gas producer in East Kalimatan that has been able to compensate for other producers' declines by pumping (27 bcm per year). Because of declining production from Vico and Chevron, the Bontang plant in recent years has been reducing LNG exports.

In early 2005, Pertamina negotiated the rescheduling of some 51 cargoes of its total 450 cargoes under long-term contracts with Japan, Korea and Chinese Taipei for 2005. In December 2005, BP Migas, the country's upstream regulator, and Pertamina advised that a total of 61 cargoes would be cut from Indonesia's 2006 shipments; 52 cargoes from Bontang and 9 from Arun.

In 2007, the Bontang plant is expected to deliver 41 fewer cargoes than its contractual commitment of 359. Arun expects 12 fewer cargoes this year than its contractual commitment of 78. In total, the reduction is 12% of the original contractual volumes in 2007. The cargo reduction equates to about 1.6-1.8% of the global total LNG trade, which comprised an estimated 3 300 cargoes in 2006.

Indonesia's LNG is supplied on mostly long-term contracts, with about 61% going to Japan, 26% to Korea, and the remaining 13% to Chinese Taipei. Some Arun contracts are due for completion in 2007 while Bontang contracts are due to finish between 2011 and 2018.

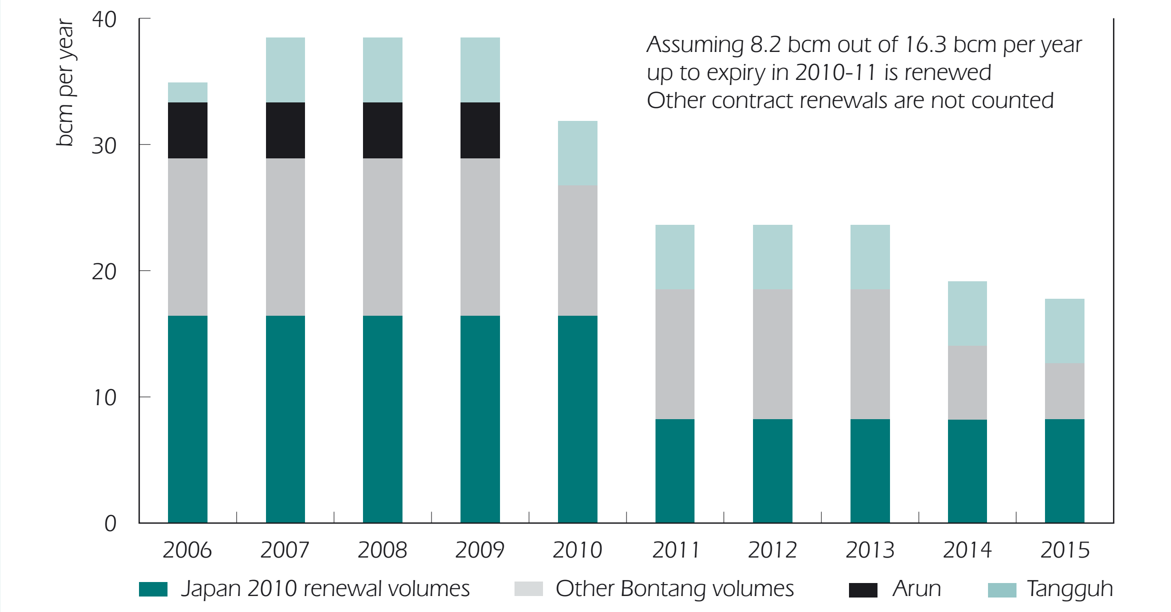
Japanese buyers hope to renew contracts for half of the 16.3 bcm per year (12 mtpa) of Indonesian supply contracts set to expire in 2010-2011. Those buyers are Kansai Electric, Chubu Electric, Kyushu Electric, Osaka Gas, Toho Gas and Nippon Steel. Their combined contractual volumes of 16.3 bcm per year (12 mtpa) account to about 20% of Japan's annual LNG imports. The two sides started full-fledged discussions on contract renewals in June 2004 and agreed to key commercial terms for partial extension in September 2005, yet no final agreement has been reached. At least 4.1 bcm per year (3 mtpa), and potentially as much as 8.2 bcm per year (6 mtpa) is expected to be renewed.

Since 2005 Indonesia has been giving strong signals that it will in the future give priority to its domestic market, as it wants to reduce its dependence on expensive imported oil. International companies are wary about this as domestic gas prices are at least a third less than international prices. Foreign companies are hesitating to develop reserves, fearing the government will force them to sell cheaply into the domestic market.

The 2001 Oil and Gas Law states that all new contracts should reflect the "domestic market obligation" to sell 25% of gas production in the domestic market. The practical enforcement of this law is not particularly clear, nor is future policy. This lack of clarity in the gas laws is hampering the effort to boost gas production. In early 2007, Indonesia revised its domestic gas policy, with new contracts expected to deliver at least 42% of their production to local markets, instead of the 25% mentioned earlier, which could alienate foreign investors even more.

Indonesia's Energy Minister is apparently seeking better production sharing terms at the offshore Mahakam Block when its contract with operator Total expires

Figure 30 Indonesia's LNG sales commitments



Source: Company announcements.

in 2017, including a greater share for production split for the government, although the minister also said recently that the government is considering a new production split of 51% for the government and 49% for producers, compared to the common 70-30 split. The minister's idea was revealed after Total said it would invest USD 6 billion in Indonesia on exploration and development over the next five years. The company wants an extension of existing conditions before the USD 6 billion commitment.

The Ministry of Energy and Mineral Resources of the country set up a task force to evaluate the country's gas balance and determine how much volume will be available for export after its domestic needs are satisfied. The group also includes representatives from upstream regulator BPMigas, Pertamina and Indonesia's main production sharing contractors, and plans to complete its work by the end of the first quarter of 2007.

Another Japanese buyer, Tohoku Electric, who buys 1.1 bcm per year (0.83 mtpa) from Indonesia's Arun through 2009, signed a heads of agreement to buy 0.16 bcm per year (0.12 mtpa) from Indonesia's Tangguh LNG venture in December 2006. The deal runs for a period of 15 years from 2010. The BP-led Tangguh venture has a contract with the promoters of China's Fujian terminal for 3.5 bcm per year (2.6 mtpa), starting in 2008. Other term deals from the venture include two Korean sales which have already started before actual start of production from the plant: one with Posco for 0.75 bcm per year (0.55 mtpa) and another 0.82 bcm per year (0.6 mtpa) contract with K-Power. A further 5 bcm per year (3.7 mtpa) has been sold to Sempra at its Energia Costa Azul terminal in Mexico's Baja California from 2008. The two-train Tangguh project is 55% complete as of the end of 2006. Start up is expected in late 2008.

Pertamina announced in December 2006 that it would not extend beyond its end-2009 expiry date a 2 bcm per year (1.5 mtpa) contract with Chinese Taipei's CPC Corporation, citing that Japan is being given preference as it was Indonesia's earliest buyer in 1973. CPC has another contract of 2.5 bcm per year (1.84 mtpa) that expires in 2017. Subsequently Chinese Taipei has cut its 2010 demand forecast for LNG by almost 20%, from 17.7 bcm per year (13 mtpa) announced in 2005 to 14.3 bcm per year (10.5 mtpa), moving away from its policy of favouring gas to generate electric power in issuing licences to independent power producers after 2007.

Meanwhile, a controversial pipeline project linking East Kalimantan to Java appears to have collapsed due to shaky economics. Gas-fired power plants on Java are now expected to be supplied from ExxonMobil's nearby Cepu block. This could ease some pressure for domestic use from Bontang.

Other possible LNG export plans in Indonesia

Central Sulawesi

Pertamina and private upstream player Medco Energi selected Japan's Mitsubishi Corporation late 2006 to be their partner in the proposed 2.7 - 3.4 bcm per year (2 - 2.5 mtpa) Central Sulawesi LNG project, due to come on stream by 2009 - 2010. This plant would be supplied from Pertamina's wholly owned Matindok block and the Senoro area, which is jointly held by Pertamina and Medco. The blocks are estimated to have 2.4 tcf (68 bcm) of gas.

Tangguh expansion

The Tangguh project is considering a third train to supplement two 5.2 bcm per year (3.8 mtpa) trains already under construction to be completed in 2008 - 2009. Buyers in Japan are interested in expansion volumes from the venture. Gas reserves are sufficient to support another train. Tangguh's partners say that they might be willing to reserve as much as 2.7 bcm per year (2 mtpa) for the domestic sector, possibly to an import terminal proposed by state-owned power generator PLN on Java.

Natuna

In 2006, Malaysia's state Petronas was said to be in discussions with Pertamina and ExxonMobil for pipeline gas from Indonesia's Natuna D-Alpha field. Gas from the field could be piped to Sarawak Island to provide extra feed gas for expansion trains at Malaysia LNG's Bintulu complex. After cancelling a production-sharing agreement (PSA) with ExxonMobil for the block, Pertamina plans to renegotiate the renewal of the PSA. The block contains an estimated 222 Tcf of gas reserves with high carbon dioxide content of about 70%. About 46 Tcf (1,300 bcm) of gas is believed to be recoverable, but the separation of CO_2 is a big challenge.

Masela Block in the Timor Sea

Masela Block in the Indonesian portion of the Timor Sea is held by Japan's Inpex. The company claims that it has found enough gas in the block's Abadi fields to support a 4.1 bcm per year (3 mtpa) liquefaction plant starting around 2014. Inpex earlier said the reserves might be used to feed a liquefaction plant in Indonesia, an idea that Jakarta apparently still favors. However, Inpex now says it plans to pipe Masela gas to an LNG plant in Darwin, northern Australian, which already hosts another 4.5 bcm per year (3.3 mtpa) LNG plant.

GAS FOR POWER

- Power has been the major factor driving gas demand growth in OECD countries and will be the "fuel of choice" for the vast majority of new power plants to 2012.

- Gas fired power provides flexibility in electricity systems. The relatively low capital cost of adding new capacity makes it ideal as a spare generation reserve in electricity systems, improving reliability.

- Gas often provides supply to meet peak demand and often sets the price of power in a number of IEA markets – high gas prices can therefore mean high power prices, but lower business risks for plant operators.

- A new investment cycle in power generation is approaching; planning now includes more coal fired units as gas prices have risen and concerns on gas security of supply have grown.

- A key challenge is to ensure that planned coal plants enter the generating mix quickly, but climate-change policy uncertainty, in particular, is affecting these investment plans.

- In the absence of sustained new coal construction, gas will continue to be the default option for new power generating capacity in OECD countries, as nuclear will not arrive in any scale at the earliest until after 2015.

- Renewables cannot fill the gap in this time frame if other construction plans do not proceed. In fact, intermittent renewables such as wind may increase the role of gas-fired power in grids.

- Gas and power markets are becoming much more strongly interlinked, affecting decision making in regulation, energy security, the need for gas storage, and the role of renewables.

Power use drives gas demand growth

Power generation accounted for around half of growth in gas use from 1990 to 2004; over the most recent five years, this proportion rose to nearly 80%. As OECD gas saturation is being reached, gas-fired power is driving growth in gas demand. Even in 2006, with gas prices high, gas-fired power production grew in a number of markets, most notably the United States by 6.5%, to meet high summer power demand.

Demand for gas in power generation in the OECD increased from 213 bcm in 1990 to 447 bcm in 2004; an annual average growth of 5.4%. Growth does appear to be slowing down; during 1990-1995 average annual growth was 7%; during 1996-2000 it was 5% and the last four years to 2004 it was 4%. From 1990 to 2005, the share of gas-fired power in the mix almost doubled, from around 10% to nearly 19%.

Forecasts by IEA member countries indicate a continued strong contribution from gas in many IEA countries, as shown in the table of the IEA's largest electricity users excluding Japan and Spain (similar forecasts not available to 2020). In the majority of cases, gas meets a high

Table 22 **Increase in electricity generation from gas in selected IEA member countries**

	Increase in gross gas-fired power demand forecast between 2004-2020 (Twh)	Increase in gross total power demand forecast between 2004-2020	Gas as a percentage of incremental power demand growth between 2004-2020	Notes
Canada	150	185	81%	
Germany	87	-10	n/a	Gas to replace Nuclear and coal
France	57	96	59%	
Italy	142	138	103%	
Turkey	105	330	32%	
United Kingdom	102	40	255%	Gas to replace Nuclear and coal
United States	447	1294	35%	

Source: IEA statistics and forecasts submitted by IEA member countries.

proportion of incremental demand, or substitutes for energy sources having a lower share (*e.g.* Germany).

Gas as the fuel of choice for new power plants, 2000-2004

Total OECD generation capacity increased by 35% from 1990 to 2004; of this more than two thirds was gas-fired. Of the gas-fired capacity built, 64% was high efficiency combined-cycle gas turbines (CCGTs). The vast majority of the CCGTs were added in the United States although CCGTs accounted for 22% of total OECD capacity increase in 1990 - 2004. So much gas-fired capacity was built that it oustripped demand for power, and many CCGTs are now operating at less than 35% load factor. Because of this there is substantial latent demand for gas in the power sector without any new investment in capital stock. This dynamic is a very important legacy of the 2000 - 2004 investment period.

United States: use of gas in power generation driven by summer peak demand

This growth in CCGT capacity levelled off somewhat in 2004 and 2005, mainly due to a general slow down in investment in new generation capacity after the United States investment boom. However, the lion's share of new capacity in 2005 in OECD was still CCGT. Some 5.5 GW of CCGT capacity was added in Italy in 2005 (7% increase of total installed capacity), 4.5 GW CCGT was added in Spain (6% increase of total installed capacity), and 14 GW in the United States. Over two thirds (70%) of new plants that came into operation in IEA Europe in 2005 were gas-fired. In IEA North America the share was 78% and in IEA Asia and Pacific it was 22%.

With the additional generating capacity, gas was able to fuel a significant share of the increase in IEA power generation between 2000 and 2004 (Figure 32). However, coal and nuclear capacity has also been up-rated or returned to the mix. In 2005, gas-fired generation contributed a lower share of the increasing power needs, because high gas prices provided strong incentives for an increase in coal-fired generation from existing plant.

The United Kingdom is a good example of the increasing importance of gas in power generation, but also its close interaction with coal-fired generation, particularly in competitive markets. Figure 33 shows power generation by fuel as shares of

Figure 31 Electricity consumption in selected months since 2001

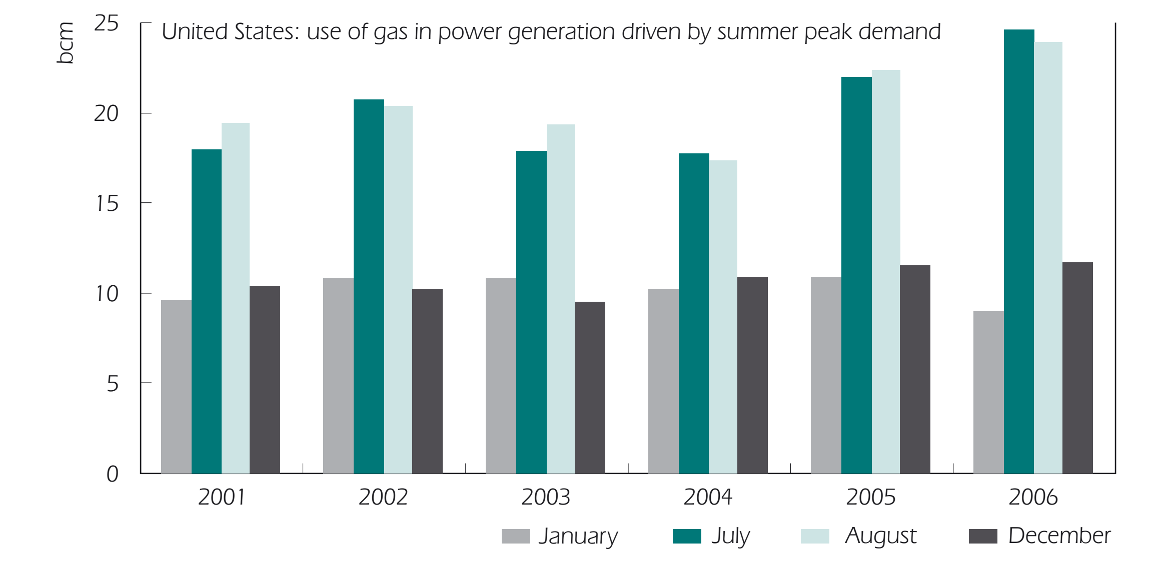
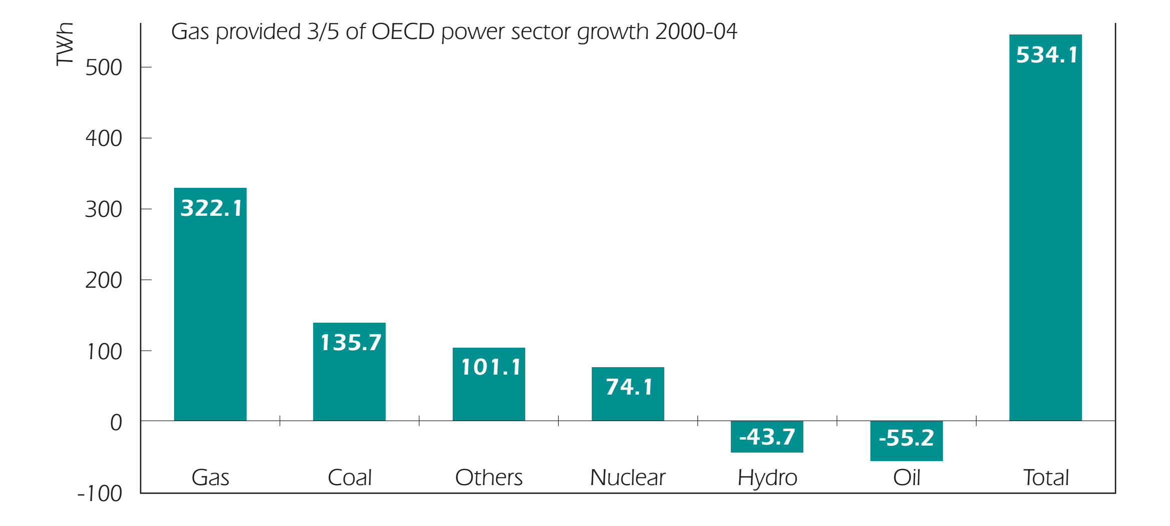
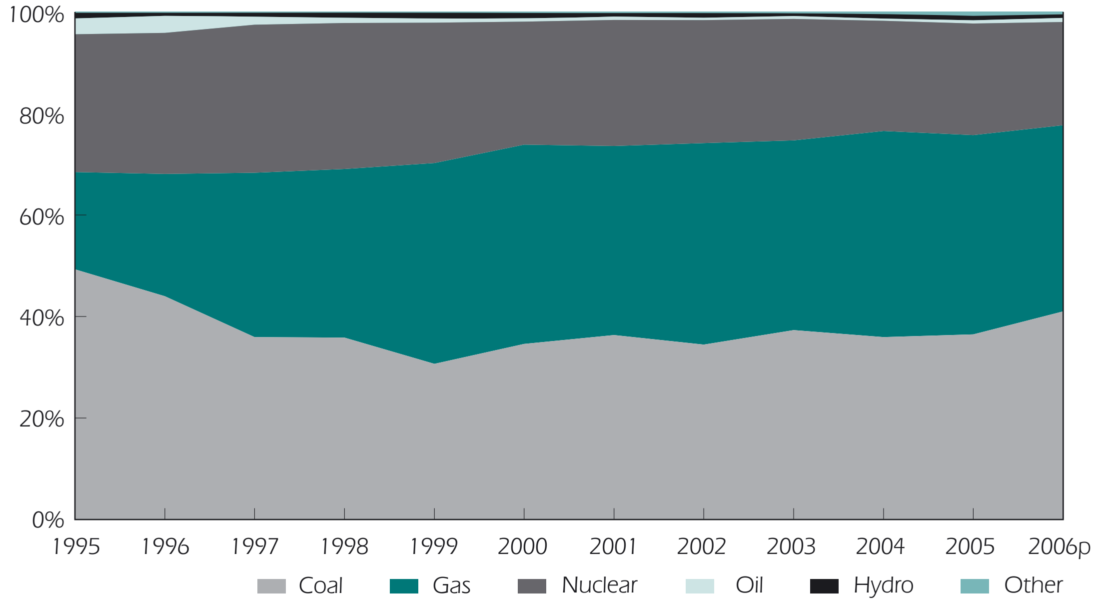


Figure 32 OECD power generation growth



Source: *Electricity Information 2006*, IEA.

Figure 33 **Shares of coal-fired generation in the United Kingdom were at their highest level in a decade in 2006**



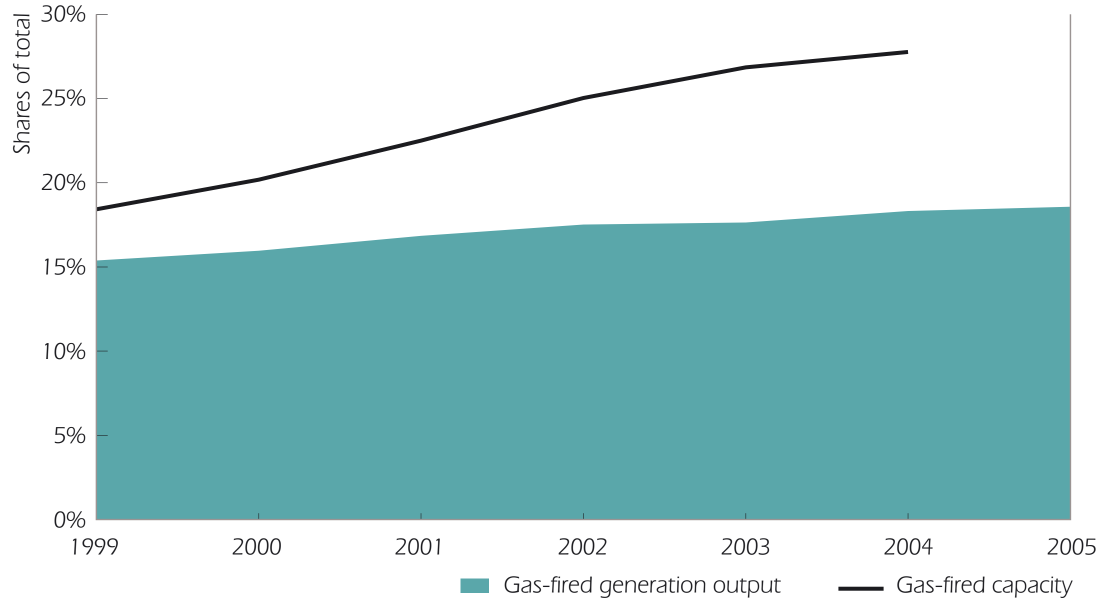
Note: 2006 data are provisional.
Source: DTI.

total generation in the United Kingdom. Total power generation increased by 25% from 1990 to 2005. The importance of gas has increased considerably since 1995, starting from more or less zero in 1990. This increase was at the expense of coal and nuclear power. The share of coal-fired generation decreased from some 65% in 1990, to 50% in 1995 and to below 40% since 1997. But the share of coal and gas has varied considerably around the same levels since then. The share of electricity generated from coal increased sharply from 34% to 39% in 2006 displacing gas and nuclear. This was caused by higher gas prices, especially at the start of the year. But by the end of 2006, as gas prices fell, the process had reversed and gas was once again the fuel of choice.

Enormous scope still exists for increased demand for gas for power generation, because gas-fired plant tends not to be used as base load plant, as illustrated in Figure 34. Hence, the share of gas-fired capacity is considerably higher than the share of gas-fired generation output. If gas prices stay competitive, or other energy sources are not available, because of delays in new plant construction or reductions in output from existing plant, existing gas-fired capacity can be utilized more extensively, of course driving gas demand upward.

There has been significant investment in wind power in countries such as Spain and Germany, on the back of sustained high subsidies, including fixed feed in tariffs. In Germany, some 17GW of wind power

Figure 34 **Gas-fired generation capacity and gas-fired electricity production in OECD countries, as a share of total**



Source: IEA statistics.

(about 17% of capacity), generates close to 5% of electricity production. Apart from this considerable investment in wind power capacity, there was an almost exclusive focus on CCGTs in most of the IEA in the past decade. And forecasts from many IEA countries show a prominent role for gas.

However, high gas prices and security concerns are driving a rethink of this approach. Looking forward, this almost complete dominance of CCGTs is showing signs of change in several countries. The United States' generation sector is turning its interest towards building more efficient new coal-fired power plants and considering building new nuclear reactors. In its latest Annual Energy Outlook published early in 2007, the United States' Energy Information Administration (EIA) is projecting a 2:1 ratio for gas-fired versus coal-fired capacity additions in the 2006-2010 period, a 1 to 1 ratio for the 2011-2015 period and an approximately 2:3 split for the 2016 - 2020 period. In Germany a high level of new investment activity is proposed and a high share of the planned plants is coal-fired. The German Electricity Association estimates that 31.5 GW of new generation capacity will be commissioned by 2012, of which roughly one-half is coal-fired, one-quarter is gas-fired and the rest is renewables, mainly wind. Another 13 GW is proposed in Germany by 2016 of which about 5 GW are renewables, 4 GW are gas-fired and 3.5 GW are coal-fired. In Australia, close to 4.5 GW is either under construction or in advanced planning, with most of the expected capacity additions to be gas-fired and renewable (gas will go from 14 to 20% of power by 2020). In Japan, the government is considering plans to build around 12 additional nuclear reactors over the next decade. It has also set a target of 3 GW installed capacity from renewable power by 2010. In Korea, more than 19 GW of new capacity is expected to be on line by 2017, which will include 9.6 GW of nuclear, 6.1 GW of coal-fired capacity; the remainder is composed of renewable, oil, hydro and gas-fired.

According to the most recent Platts database (Platts, 2006) 62% of plants under construction in IEA Europe are gas-fired, and 53% of planned plants are gas-fired. For IEA North America the corresponding shares are 49% under construction and 32% of planned plants. In IEA Asia & Pacific 27% of plants under construction and 30% of planned plants are gas-fired. This represents an increase in planned coal fired plants, but planned plants do not generate electricity. The challenge is to take these plants from planned to construction through to completion speedily. Uncertainty on future climate change policy is a primary factor in Europe, (and to a lesser extent North America) slowing these plans. Coal fired plant investments cost more than double gas investments, using significantly more risk capital while coal fired power, even at best practice has double the greenhouse signature of gas-fired CCGT.

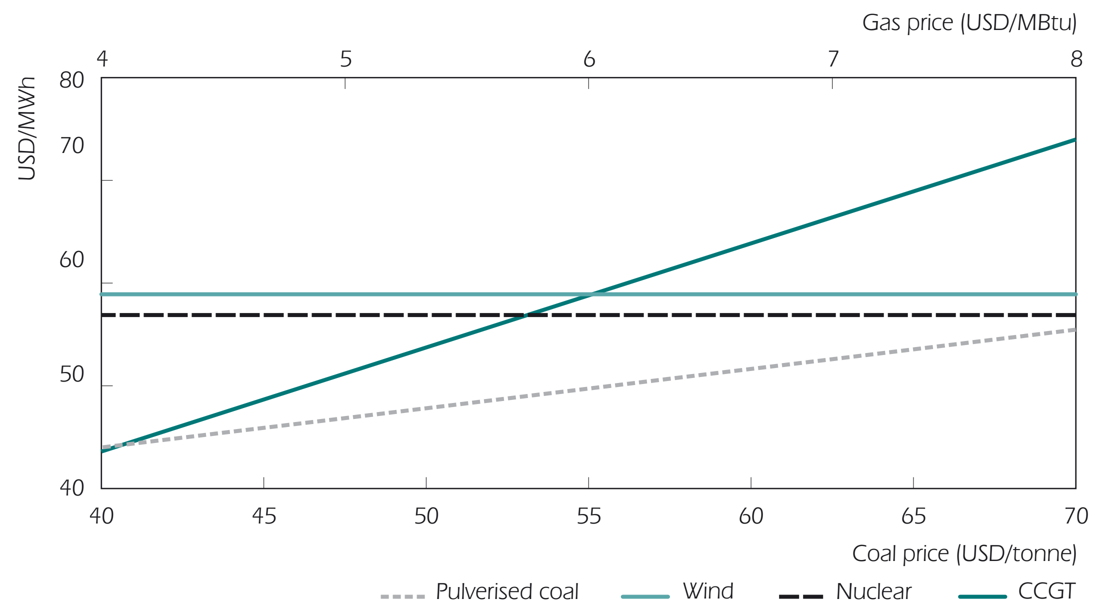
The IEA *World Energy Outlook 2006* projects that 681 GW of new generation capacity will have to be built by 2015 in the OECD to replace retired plants (215 GW) and to meet increasing demand (466 GW). About 30% of these new builds are projected to be gas-fired. These plants are also driving the projected increase in gas demand for power generation. Gas-fired generation is projected to contribute to about one third of the projected increase in power generation to 2015, corresponding to 661 TWh. (around 160 bcm of new gas demand at current efficiencies). To 2030, *WEO 2006* anticipates that gas-fired power will more than double, despite a higher price outlook than a year earlier.

Economics of gas-fired generation

The economics of gas-fired generation, and its competitiveness relative to other generation technologies, depend on a number of key variables, including capital costs, fuel costs, planning and construction time, operating and maintenance, capacity factors, cost of capital, plant life and discount rates. The competitiveness of various technologies can be assessed on the basis of the levelised lifetime costs, essentially a measure of the real average generation costs of a technology over the economic life of a power plant.

Fuel costs as a share of total generation costs vary significantly among technologies. Wind has no fuel costs. For nuclear power, fuel costs represent a small component of nuclear power generation, between 8 and 11%. For CCGTs, fuel costs account for about 75% of total costs. A 50 % increase in uranium, gas and coal prices would increase nuclear generation costs by about 3%, coal costs by about 20% and CCGT costs by about 38% (IEA, 2006). Considering that the price of natural gas tends to be volatile in some markets, this seems an

Figure 35 **Gas prices in the USD 4-6 /MBtu range over the long term are pivotal for the economics of CCGTs**



Source: IEA.

important drawback for CCGTs. However, it must be remembered that where gas sets the marginal price of electricity, (increasingly the case in a number of IEA countries) this volatility can be recovered from the market. In that case, of course, high gas prices directly translate into high electricity prices, which may be a severe problem for electricity intensive industry in particular, and all consumers in general.

Figure 35 shows the sensitivity of gas- and coal-fired plants to changes in gas and coal prices, at a discount rate of 6.7% (*i.e.*, the low discount rate case in *WEO 2006*). The cross-over point between nuclear and CCGT generating costs occurs when gas price reaches USD 5.70/MBtu. In other words, CCGTs have lower levelised costs than nuclear at gas prices below USD 5.8 /MBtu. Pulverised coal-fired plants remain more competitive than nuclear power plants until coal prices rise above USD 70 /tonne. These results were obtained using a generic utilisation factor of 85% for nuclear, coal and CCGT.

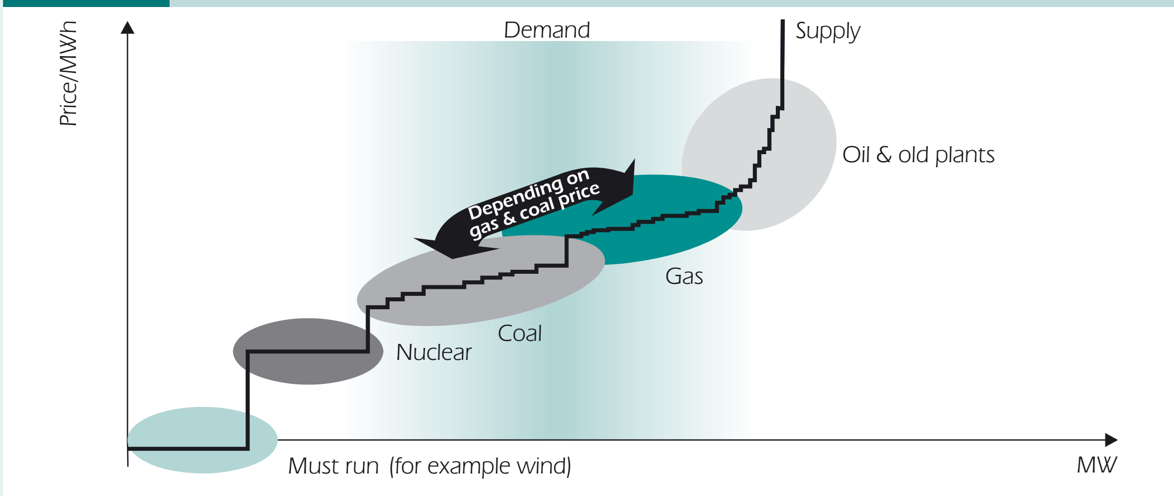
The combination of high fuel cost dependence and low investment cost dependence improves the actual market situation for CCGTs. Investment costs in a power generation plant can be considered "sunk costs" from the moment they are incurred. Once a plant is commissioned, the marginal cost of producing an additional unit of electricity should determine its operation (dispatch). Marginal costs more or less correspond to fuel costs; thus, CCGTs often have the highest marginal costs, even at relatively low gas prices. CCGTs are often the marginal plants that determine the price in competitive markets. Hence, increases in gas prices are passed on to increases in wholesale electricity prices; as noted above this can have severe consequences for some if not all consumers. High gas prices make other alternative technologies more competitive, but as long as the costs are covered, CCGTs may still be perceived as the least risky way to earn a profit, particularly given lower up front investment costs.

In markets where there is a CO_2 price, the economics of gas-fired generation, wind and nuclear would improve relative to coal-fired generation. Hydro power, CHP, biomass and distributed generation also have clear advantages over coal and gas-fired plants in terms of CO_2 emissions. These technologies may have competitively low levelised costs when beneficial conditions support their use (access to hydro reservoirs, heat demand or cheap biomass) or when underwritten by guaranteed high feed-in tariffs. Only if there is a pool of potential technologies to choose from can a price on CO_2 emissions fundamentally change investment decisions. Excluding nuclear power as an option (as is happening in a few IEA countries) reduces real generation options considerably. If local conditions are not favourable for nuclear, the only option to reduce CO_2 emissions may be to shift from coal to gas and renewables.

Gas-fired generation capacity adds flexibility

The relatively low investment costs of CCGTs have a profound impact on the way power generation portfolios are developing, and on the way gas-fired power generators behave as gas customers. The principles and incentives that drive CCGTs as gas customers are illustrated in Figure 36.

Figure 36 ***Coal and gas-fired generation often sets the price in competitive electricity markets and the merit order is highly dependent on coal and gas prices***



Source: IEA data.

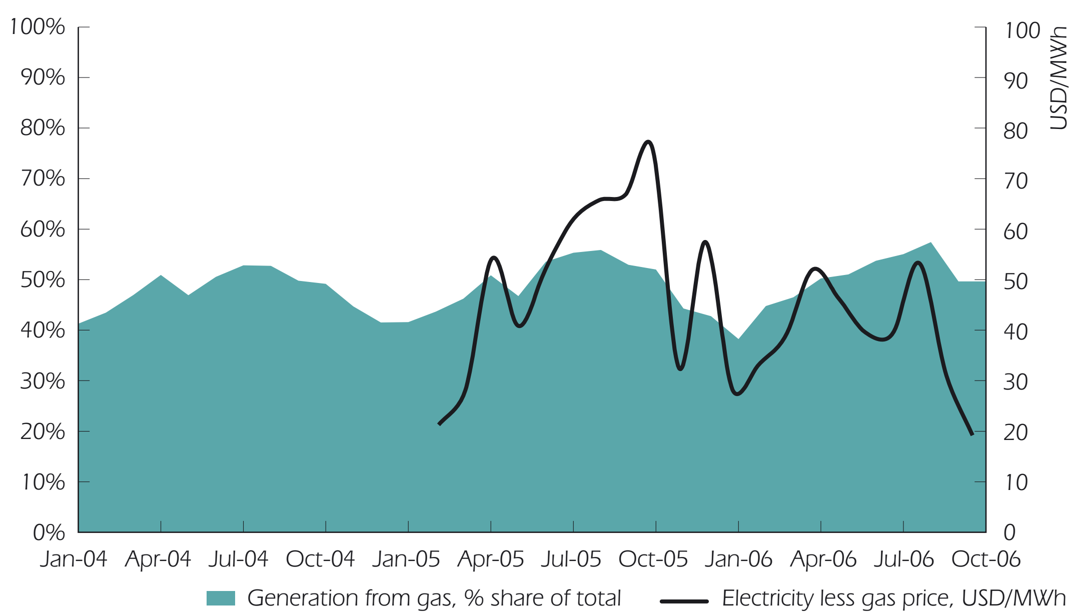
Ranking of generation plants according to a merit order of marginal costs is the corner stone of achieving optimal dispatch. The marginal MWh of demand should always be met with the MWh of supply that has the lowest marginal cost. In a competitive market the cost at which the marginal MWh is bid into the market also determines the market price. Figure 36 shows a merit order that is often seen with the current high gas prices, but the ranking of coal and gas will change according to the relative prices of those fuels. Gas has a particular advantage in meeting demand growth that is low, uncertain, and becoming increasingly volatile.

Market experience from Texas illustrates the interaction between electricity prices and gas prices well. Figure 37 shows gas-fired generation as a share of total generation, and the difference between monthly averages of gas and electricity prices.

The share of gas-fired generation in Texas is seasonal with high shares during the high loads of summer, and lower shares during the winter. The difference between electricity and gas prices is an important driver. Gas power shares are generally high when the spark spread (electricity-prices-minus-gas-prices) is high, and the shares are low when the spark spread is low.

As noted earlier, the price of fuel is a primary risk factor for gas- and also to a certain extent coal-fired plants. One measure to manage these risks is to diversify and ensure flexibility in the generation portfolio to be able to switch between technologies

Figure 37 **Gas-fired power generation as share of total generation in Texas, and difference between electricity price in Texas and gas price at Henry Hub**



Source: EIA, PUCT, NYMEX, ERCOT.

to a certain extent. In the past, with nuclear, coal and oil fired generation as the principal elements in the generation mix, such hedging through diversification was expensive, due to the high investment costs. Nevertheless, within the fully regulated environments that existed it was possible to ensure diversification and reserve capacity by passing the cost to the consumer.

The low investment costs of CCGTs have changed this balance. In the past, older coal and oil fired plants were traditionally kept in operation to serve mid-merit and peak load. Today, new CCGTs end up filling that role. One of the consequences is illustrated in Figure 34. CCGT capacity increased from a share of 18% in 1999 to 28% in 2004. Gas-fired generation as a share of total generation only increased from 15% to 18% in the same period. Installed gas-fired generation capacity in IEA countries only had a utilisation rate – capacity factor – of 31% in 2004. CCGTs seem to have added considerable flexibility into electricity systems because they are responsive to demand. This volatility of power demand therefore feeds through to a very variable gas demand, increasing the need for short-term flexibility in the gas value chain – *e.g.* storage.

The need for and value of flexibility in electricity systems is likely to increase. Un-subsidised wind power on good wind sites is competitive with conventional technologies when there is a price on CO_2 emissions. Many countries have specific support mechanisms for renewables, and wind power is the largest beneficiary of these subsidies, driving a global average annual capacity increase of almost 30% during the past decade, although capacity factors are low. Wind-power is intermittent and difficult to predict precisely. It therefore requires alternative flexible resources to be integrated into the grid. At low shares of total installed capacity this requirement is met with the flexibility that already exists in electricity systems, including from hydro plant. When the share increases above a certain threshhold (depending on the specific characteristics of the system) more flexibility will have to be added to the system. With low investment costs and high running costs, gas-fired generation is the least cost option in most circumstances. Thus, demand for the operational and financial flexibility that gas-fired generation can offer is likely to increase with the increase of the share of intermittent renewables, such as wind-power.

NON-OECD COUNTRY/REGION UPDATE

Russian Federation

Russia holds the world's largest gas reserves and produces and exports more gas than any other country, accounting for almost a third of imports into IEA Europe in 2005 (26% of imports into the EU in 2005).

Worries about general upstream gas investment worldwide also apply to Russia, but here the level of concern is amplified because of the crucial importance of Russia as the largest player in the globalising gas market.

The gas trade between Russia and Europe is critically important for ALL nations with an existing or potential stake in the global gas business.

Summary

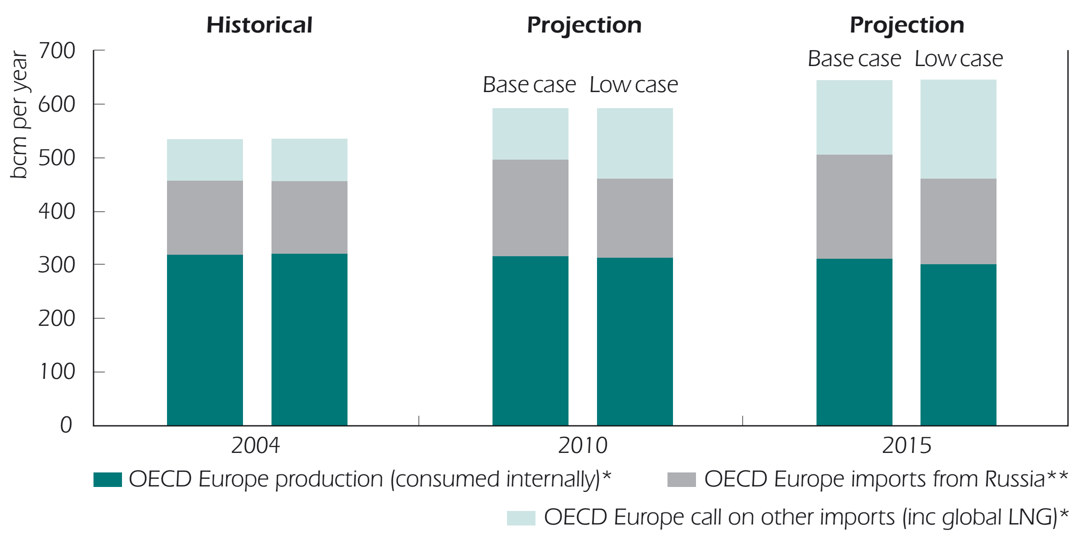
We note that Gazprom has ambitious plans to expand production in the existing producing region of Nadym-pur Tazov (N-P-T) to 2010 as well as produce first gas from Yamal in 2011. In meeting these aggressive deadlines, there is a risk that Gazprom's plans are subject to the same slippage and cost overruns we are currently seeing across the world. Such delays and cost overruns in the N-P-T region could leave the global gas balance looking clearly stretched before 2010, while slippage on such a major project as Yamal would have the same effect after 2010. In short, the level of investment that we see in Russia seems inadequate to deliver the planned production on time, yet the problem may partly be due to inadequate transparency in communicating Gazprom's investment and delivery plans.

Russia is so important to the world because future trends in Russian gas exports to Europe are a key factor in determining the degree of tightness in global gas markets and pressures on alternative sources. If its exports to Europe are lower than planned – irrespective of contractual arrangements – Europe will tend to import more from the Atlantic LNG market, drawing LNG from the Pacific (as mentioned in the separate section on regional supply and demand). If LNG flows to IEA North America in the medium term are substantially lower than projected, then the fundamentals of North American gas supply will be affected. No single factor better illustrates the globalisation of the gas market than the consequences of too little, or too much, Russian gas exports to Europe.

Recent commercial disputes with its neighbours that have cascaded into Western markets have caused many observers to question Russia's ongoing commitment to reliable supply. However, Russia's long and proud history as a reliable supplier of gas to Europe suggests that it is Russia's intention to honour contractual commitments to trade partners in IEA and the EU. But, for good intentions to translate into results, there must be real investment – particularly, but not solely into future production and transport of gas.

In a fully competitive, transparent upstream gas market, stakeholders can gauge the sufficiency of investment through, amongst other indicators, price effects. Gazprom has a gas export monopoly in Russia, it owns the transportation system and two thirds of the gas reserves. In the case of such a dominant company, there is no need to respond to gas prices by

Figure 38 **Russia/European pipeline trade affects global gas balance**



Source: IEA.
* Information from Supply/Demand section.
** Base case: Russian Government Energy Strategy (2003) total projected exports to IEA Europe.
** Low case: IEA scenario based on restrained investment.
Note: We have assumed total Russian exports per Russian Government Energy Strategy (2003) less 77 bcm of Russian gas flows to countries other than OECD Europe for all future periods (Russia supplied 77 bcm to these countries in 2005). We assume that Chinese export plans made in 2006 do not form part of this 2003 Energy Strategy.

increasing investment, as competitors can not erode its market position despite favourable economics. At the same time, the risks to Russia and its trade partners of relying on one company for all exports are considerably higher than the risks of exposure to an industry.

Exports to Europe are of high importance to Russia. Such exports account for around 27% of volumes sold and roughly 60% of Gazprom gas revenues. However, we are keenly aware that Russia not only provides gas exports to world markets, but also has commitments to a large domestic market which accounts for two thirds of gas produced. Russian per capita consumption of gas is similar to that in Canada, but consumption per USD GDP is roughly five times higher than IEA countries.

At 430 bcm in 2005, the Russian domestic gas market is the world's second largest after that of the United States and recently has been growing substantially – driven, as in IEA countries, by growth in power demand and an ongoing programme of gasification (increasing penetration of the domestic market). The reasons for growth of gas use in power generation are however different from those in IEA countries as Russia has old or underused gas-fired power stations now being returned to service or used at higher capacity factors. Despite the inefficiencies, these plants are cost effective because of the artificially low price of gas (see below discussion of "Domestic price reform"). Gazprom base-case demand projections are based on a 2 bcm/year growth in domestic demand while alternative scenarios show as much as 6-8bcm/year growth in domestic demand.

Russian gas use in the power sector (including heat) was estimated at 224.4 bcm in 2004, accounting for 420 TWh of electricity generation. Between 2001 and 2005 gas demand grew 29 bcm (about the total consumption of Korea in 2005), half of which was from power demand. Gazprom reports that demand grew by 14 bcm in 2006.

On the surface, the key issues of concern to world gas markets are a consideration of the rate of future Russian gas production and of the rate of increase in Russian domestic demand; however, there are many other factors which complicate the picture. We note with concern that reduced Russian gas flows to the domestic power sector and heavy industry have recently forced these users to decrease the amount of gas consumed. Recent announcements by various members of the government and industry leaders seem to point to a potential domestic gas shortage. In August, the Russian economics minister was quoted[14] as saying that the Russian domestic gas market may face shortages of 5 - 6 bcm over 2007/09, as domestic consumption is expected to grow by 26 - 27 bcm, while output is forecast to rise by only 21 bcm.

Deepening the analysis reveals many factors which affect gas flows to and from the Russian unified gas supply system (UGSS). We analyse each of these factors in detail below, discussing the potential upside and downside risks attributable to each factor.

Upstream investment

The IEA's *World Energy Outlook 2006* (*WEO 2006*) projects that an average of USD 17 billion per year would need to be invested in the Russian gas sector to meet projected supply growth, including projected in-terregional trade. This is subdivided into approximatly USD 10 billion needed for upstream exploration and production and USD 7 billion for transportation infrastructure. One of the reasons that the investment requirements are so great in the case of Russia is because some major fields which provided the bulk of Russian production are now declining. This investment figure also recognises that there has been considerable cost inflation in the petroleum sector in the past years and has therefore been adjusted upwards from the annual investment of USD 15 billion cited in the *WEO 2005*.

As the owner of the Russian pipeline system and developer of the Yamal region, Gazprom is called upon to account for the vast majority of upstream and almost all of pipeline investment. In early January 2007, Gazprom announced its Investment Program for 2007 which earmarked about USD 14 billion as capital investments. It was stated that this total does not apply exclusively to investment in the upstream gas sector, but also to other sectors. From the projects listed in the investment programme, we have identified plans to spend USD 3.85 billion on new upstream production in 2007.

14. Interfax (17 August 2006).

Major upstream investments in 2007:

- Kharvutinskaya of the Yamburgskoye field: USD 1 billion.
- Bovanenkovskoye and Kharasaveyskoye fields: USD 1 billion.
- Yuzhno-Russkoye field: USD 0.8 billion.
- Shtokman field: USD 0.65 billion.
- Prirazlomnoye field: USD 0.4 billion.

The details that Gazprom gives for its investments are vague when compared with the details that are given, for example, by Saudi Arabia with regards to oil investments which are similarly important with regard to that market. As with Saudi investments, the market would take considerable comfort from knowing which Gazprom fields will be brought online at what production levels and when, as well as exactly how much the company will invest in each field in order to ensure the plans are carried out.

The planned production growth of N-P-T region is the only source of new gas output in the period to 2010 according to Gazprom information. Despite Gazprom's ability to date to meet its production targets in this region, we are not confident that enough investment is being made to expand production.

In-depth details of planned development schedules for the Yamal region would reassure consumers of Gazprom target to produce first gas in 2011, as well as the expected 140 bcm per year by 2015. We are only aware of USD 1 - 2 billion of investment in this region. If first gas production from Yamal is to be delivered on time in 2011, we would expect to see a much higher rate of investment at the moment. The scale of the project and its unique environmental challenges raise concern about timely delivery.

In short, given the substantial decline in existing production, we would encourage Gazprom to provide greater assurance that it is investing in enough production to guarantee gas supplies to customers. Our analysis of investment plans suggests that there could be a substantial risk of underinvestment in the Russian upstream in general, particularly with respect to the Yamal development. We believe that this risk of underinvestment increases in light of the additional likelihood of delays and cost overruns in execution of such a challenging project, noting that such delays are being seen worldwide (see separate section on Investment).

Import dependence

The Russian gas pipeline system was conceived in the Soviet era, built on the basis of two sources of natural gas reserves – the major fields of West Siberia and those of Caspian states (Turkmenistan, Uzbekistan and Kazakhstan) which then made up part of the Soviet Union. After the break up of the Soviet Union, historical trade flows were formalized by long-term contracts which codified the interdependencies. Turkmen gas was, for instance traded for cash and goods from Ukraine under long-term contract rather than under the direction of the Soviet government.

While "Turkmen gas" still ostensibly flows to Ukraine, the key sections of the transportation system used are owned by Gazprom (the UGSS). Gazprom holds

Figure 39 **Gas infrastructure of Russia**

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA.

an import and export monopoly in Russia with few (specific) exceptions. This export monopoly means that volumes leaving Russia to Ukraine come from Gazprom, whether or not the contracts with Ukraine and Central Asia net off in its portfolio. Similarly, existing gas flows from Turkmen to Ukraine through Russia must be planned within the context of the capacity of the UGSS. Whether or not they are destined for Ukraine, some projections show Turkmen gas flows to Russia increasing to 80 Bcm in 2010, a substantial volume equal to the total imports of Germany.

There are several risks in Russia's strategy of relying on future imports from Central Asia:

- Caspian gas reserves should not be regarded as exclusively for Russian use. New export routes from the Caspian region could put pressure on Russia's long-term import agreements/expectations over time. Both China and the EU would like to tap resources in the Caspian region in the medium term, as discussed in the separate section covering Central Asia.
- The existing pipeline from the region into Gazprom's "Unified Gas Supply System" – the Central Asia Centre (CAC) is capable of operating at only 50 bcm throughput, well below nameplate capacity. It is in urgent need of refurbishment. Gazprom has delayed refurbishment of the pipeline until an international audit of Turkmen reserves has been performed.
- The last time there was an audit of the actual reserves in place in the region was in Soviet times. This audit confirmed that

there were at least 3 tcm of reserves in the 1980's but of course a portion of this has been produced since then.

- There could be considerably more than enough reserves in the Caspian region, but an official audit is needed to confirm this.

Duma deputies and energy policy makers appear to have recognized the risks of relying on Central Asian gas and have called for a co-ordinated approach to gas exports from the region. In this way they hope to ensure Turkmen gas uses the Russian system rather than competing against Russian export plans to Europe and China. Turkmenistan Eastern reserves and the Chinese West-East gas pipeline systems are already a relatively short geographical distance from each other (compared with the length of pipelines already in place) as discussed in the separate section on Central Asia.

The increasing nominal price that Gazprom is prepared to pay to Turkmenistan for gas underlines the importance of this gas to the Russian balance. In 2004 and 2005 Gazprom transited 40 - 50 bcm per year of Turkmen gas to Ukraine and bought another 5 - 7 bcm per year for its own use at approximately USD 1.16/MBtu (USD 44/1 000 m^3). In 2006, Gazprom agreed to import 50 bcm at a much higher price of USD 2.64/MBtu (USD 100/1 000 m^3) for 2007 to 2009. It is impossible to verify the cash proportion of these trades given the history of barter in the trade.

We are concerned that Gazprom is banking on being able to secure increasing volumes of Turkmenistan gas when there are other potential suitors for the reserves in the region who could be producing before 2015. Not least, we are aware that in 2006, Turkmenistan signed a long-term agreement with China for the export of 30 bcm per year starting in 2009 albeit from Turkmenistan's under-developed Eastern fields. Furthermore, we are aware of no large-scale investment into new production in Turkmenistan, the only Caspian state with reserves to support it.

Eastern export strategy

Energy exports to China are important to Russia in the longer term, given its interest to diversify its export markets. Developing the oil and gas resources of East Siberia meets Russian economic as well as social and political objectives. The reserves currently supplying European markets in Western Siberia, however, could not be economically targeted for Eastern Markets given the presence of other reserves much closer to the East. Russian references to West Siberian gas when discussing its "Eastern Ambitions" are confusing, but might be a negotiating stance with Europe.

Russia has a long standing declaration of intent to co-operate with China given the East Siberian oil and gas resources and China's interest in importing increasing volumes from its neighbour. This was discussed at the highest levels in spring 2006 when inter-governmental framework agreements were signed by President Putin of Russia and President Hu Jintao of China. President Putin stated that Russia could potentially supply an annual total of 60-80 bcm of gas to China via two routes. Gazprom stated that the planned USD 10 billion 3 000 km Altai pipeline system (the western route) would pump the first Russian gas to China as early as 2011 though construction of the Russia-China section of the system has not started.

The Kovykta field in the Irkutsk region of East Siberia could be a possible source of production for export to the East, as could Sakhalin. Nevertheless, plans to supply pipeline gas from Russia to China by 2011 are very ambitious indeed. Gazprom's increasing assertion of control in these regions has slowed the rate of investment that has been made by private investors. Gazprom is becoming increasingly active in Russia's potential gas regions in the East – East Siberia, the Far East and Sakhalin island. Events surrounding the recent buy-in to the Sakhalin II project for USD 7.45 billion have affected project development for environmental and regulatory reasons. To date, developments at Kovykta, another potential source for gas exports to China, are very slow, allowing Gazprom to press for entry.

There have been considerable difficulties in negotiating gas prices with China. Gazprom wants oil-based prices, while China is seeking much lower coal-based prices. If pipeline prices were, for example linked to LNG prices in Beijing or Shanghai regions, such prices are likely to be closer to Japanese (JCC linked) or perhaps United States prices.

Independent gas producers

In 2006, non-Gazprom natural gas production reached 106 bcm; accounting for 16% of total. The Russian Energy Strategy assumes that the share of such "independent" production out of the total transported by the Gazprom system will increase to 20% (140-150 bcm) by 2020. A review of various projections from the key non-Gazprom gas producing company websites reflects a much more bullish outlook, with potential production volumes of over 300 bcm per year possible in the period 2015-2020 if the investment climate is favourable. Independent gas producers and major Russian oil companies control about a third of Russian natural gas reserves – on the order of 11 tcm.

In order to build a sustainable gas business, independents will need considerable security that the volumes contracted for and delivered will actually be taken at the price agreed. There is tremendous potential for more gas to be produced in Russia for several key reasons: oil producers, including Gazpromneft, flare associated gas which is a by-product of oil production; much non-associated gas stays un-produced because the access conditions to the pipeline network are not adequate; some gas is produced beyond an economically recoverable distance from the pipeline system.

The solution to ending gas flaring might appear to be simply by ruling it unlawful – but this is not a workable solution as it is likely to result in a dramatic decline in accompanying oil production. Instead, improved economic incentives to remunerate gas production will have the double benefit of reduced flaring and increasing non-associated gas production. There are two areas which would seem to need attention: access to transportation capacity and price.

Regarding access to transportation, economic conditions which may lead to increased independent production include improving the general regulatory environment and specifically, continuing to improve pipeline regulation to ensure that it is cost reflective. Progress has been made recently in this effort following the formation of a "Gas Market Coordinator" partnership in 2004 between producers and consumers to agree the main principles of gas market reform. This partnership has recently delivered substantial improvements in the terms of access to the Transportation System including for longer periods than in the past. More work remains to be done, but this seems to be a positive development for independent gas production in the Russian upstream.

Regarding pricing, wellhead prices for independent gas production in Russia will depend heavily on domestic market prices as the "premium" export market seems likely to be controlled by Gazprom. Reform of domestic gas pricing will therefore have a large effect on gas production from independents. It is essential that prices rise to levels where producers can earn revenues in excess of cost after transportation and essential gas processing (see section below, on Domestic Pricing).

However, even after issues of access to transportation capacity and price are addressed, there will remain myriad challenges facing independent gas producers in Russia. The key seems to be in ensuring that the power of Gazprom as a monopoly buyer/transportation provider is balanced so that independents have confidence that they can sell gas and that they will be paid a profitable, pre-agreed price.

Gas transportation capacity

The UGSS transported about 700 bcm of gas in 2005 and is reaching the upper limit of its current capacity. According to plan, by 2020 the UGSS will need to transport between 580 and 590 bcm of Gazprom gas and up to 140-150 bcm of non-Gazprom gas.

The Russian part of the transmission system was built mainly between 1975 and 1990, when the massive increase in gas production from West Siberia occurred. Most of the export pipelines were built in the 1980's. Between 2002 and 2006, Gazprom refurbished the trunk gas pipeline system, compressor stations and gas storage facilities. Throughput volumes in 2004 were up 6% in comparison to 2001, which gives confidence that investments undertaken in this third phase were close to target levels.

A fourth programme from 2007-2010 was approved in September 2006 with a goal to increase rated throughput capacity by 35 bcm per year and to decrease fuel input needs for the transmission system by 3.5 bcm per year. An earlier discussion of this fourth phase had a goal to increase capacity by 24 bcm per year at a cost of USD 3 billion per year.

Major gas transmission projects in 2007:

- Northern Tyumen to Torzhok pipeline: USD 0.7 billion.
- Expanding the Urengoy hub: USD 0.6 billion.
- Expanding the northwestern network (including Nordstream): USD 1 billion.
- Branch pipelines and distribution stations: USD 0.5 billion.
- Upgrading gas transmission facilities: USD 1.8 billion.

Focus on storage

Storage works in tandem with transportation capacity in most pipelines systems worldwide. Storage facilities help to smooth out seasonal fluctuations of gas demand, allowing pipeline systems to run at higher average rates over longer periods. There is substantial room for improved transport capacity in Russia if storage investment near demand centres is increased. This could be a significant contribution to the quality and cost of supply if the investments are made in the right areas.

Existing gas storage facilities are an integral part of the UGSS and are situated in the main gas consumption regions. Gazprom uses storage to supply up to 20% of demand during the heating season and up to 30% of gas to Russian consumers during cold snaps. Storage is a stated "strategic objective" for Gazprom because it considers investment to be 5-7 times less expensive than development of reserves and corresponding transmission facilities that would otherwise provide the swing output (see section on Gas Security for a discussion of the role of gas storage).

In 2005, Gazprom reported that it was able to inject 46.3 bcm of gas into its storage facilities and withdraw 42.8 bcm. Three new underground gas storage (UGS) facilities are currently under construction in Russia which will add some 1.9 bcm to the working volume reported in 2005, compared to annual gas demand in Russia which runs at some 425 bcm.

Gazprom also stores gas abroad. Gazprom is responsible for developing the largest storage facility in Germany at Rehden, the largest in Austria at Haidach, which will also serve German customers, as well as 50% of the Humbly Grove UGS facility in southern Great Britain. Gazprom also uses storage facilities in Ukraine (in co-ordination with RosUkrEnergo), Latvia, Germany and Austria. A new storage facility is also planned in Belgium.

Gazprom's focus on storage in downstream markets is a sensible use of capital given that many of the pipelines in the UGSS run well below maximum capacity in summer when demand is low. With increased storage at demand centres, Gazprom will be able to transport more gas in the summer and increase the effective capacity of the UGSS without building new pipelines.

Focus on "transit avoidance" pipelines

Gazprom has stated that it wants to build several "transit avoidance" pipelines, including Bluestream II, Nordstream and a new Southern corridor to take Bluestream gas through Turkey to Western Europe.

Table 23 Investments in transit-avoidance pipelines

Name	From	To	Avoiding	Cost (USD billion)
Nordstream	Russia	Germany	Poland, Belarus	11.4
Bluestream II	Russia	Turkey	Ukraine	6.0
Southern corridor	Russia	Austria, Hungary	Ukraine	7.0
Total				**24.4**

Source: Gazprom company statements and IEA estimates.

The total estimated cost for these projects is some USD 24 billion in the current environment of high cost inflation. Even if these projects succeed in their strategic aim of reducing gas transit dependence, they do not address the root causes of potential transit problems in the future. The proposed pipelines do not remove dependence on transit states entirely or add to upstream gas investment which would result in higher gas production.

The capital earmarked for these pipeline systems would be better spent addressing concerns about Russian upstream gas production (or the efficiency of downstream gas use). Meanwhile Russia could consider proceeding with multilateral political efforts to put its relationships with transit states on a more reliable footing.

Domestic price reform

Gazprom sells gas in the domestic market at wholesale prices regulated by the Federal Tariff Service. In 2005, Gazprom sold 307 bcm on the domestic market for about USD 13 billion, an average price of USD 1.11/MBtu (USD 42/1,000 m^3). Russian per capita consumption of gas is similar to that in Canada, but consumption per unit of GDP is roughly five times higher than IEA countries. Gazprom has argued for years that regulated prices are below replacement cost levels and contract prices to Europe. Despite low prices, Gazprom has ongoing problems in collecting payment from Russian customers – in 2005 it reported a total of USD 2 billion in total unpaid bills.

Price reform is not just a Gazprom issue - low prices for the final customer mean even lower prices at the wellhead. At these prices, gas is regarded as a by-product of oil which must be disposed of in a cost effective way. Independent oil producers are keen to get access to gas processing facilities in order to remove liquids from the stream and to dispose of the associated gas. Nevertheless, at such low gas prices, flaring is widely used to dispose of associated gas – official figures suggest that 15 bcm per year is disposed of in this way. Together with the National Oceanic and Atmospheric Administration of the United States (NOAA) the IEA has estimated maximum flaring by oil companies in West Siberia at 4 times the official figure (see *Optimising Russian Natural Gas*, IEA 2006). Even if the actual amount of economically recoverable associated gas were some 20-25 bcm per year, capturing this volume alone would allow Russia to supply the entire annual gas use of a country such as Belgium.

We note that Russia accounts for some 50 bcm per year of consumption as "own use" in the gas sector itself. We consider that perhaps 5-6% of total transported volumes could reasonably be expected to be necessary for compression in such a large transportation system. This implies that there is potential to save some 10-15 bcm per year of gas by installing more efficient compressors and reducing leaks. A rise in domestic prices should provide the economic incentive for Gazprom to invest in equipment upgrades which could start to meet its own target – a reduction of 10 bcm per year by 2012 (see, Ibid).

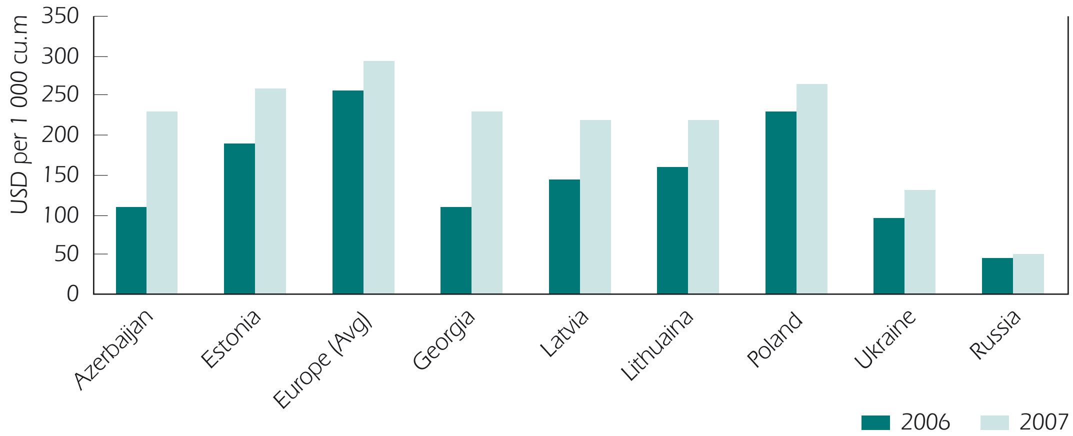
From a consumer perspective, low gas prices coupled with a lack of metering, mean a lack of incentives to avoid inefficiency and waste. According to CDU TEK (the statistics arm of the Russian Ministry of Industry and Energy) domestic gas demand growth has been above 3% per year in 2005 (3.82%) and 2006 (3.03%). This is high for such a large and relatively mature industry. Throughout this book we note that power remains the driver for gas demand and Russia is no exception. However, because of the prices, the average efficiency of gas use in the power sector for example is low. An upper bound estimate of potential gas savings in Russia is in the order of 80 bcm per year of gas if all end use equipment was upgraded to state of the art efficiencies over a period of time (see *Energy Technology Perspectives*, IEA 2006).

Annual gas price increases in the order of 25% or more are planned – although elections in early 2008 could slow the pace of these plans. The outlook is for domestic gas prices to about double from current levels to just over USD 2.64/MBtu (USD 100/1 000 m^3) in 2010, still only 40% of current European export prices (which may change in the interim). President Putin has stated that he expects Russian domestic gas prices to level off at a rate of 60-70% of European prices given the transportation netback. Domestic prices still have a long way to go after 2010 to match this intended ratio given the differential of nearly USD 5.28/MBtu (USD 200/1 000 m^3) based on current prices. Despite the intention to raise prices to "European levels", it is worth noting that most gas producing countries with which Russia must compete in number of sectors, have very low level of gas "feedstock" prices (see separate MENA section for example). This factor may act to limit the scope for price rises in those sectors.

The establishment of a gas exchange in Russia, where up to 10 bcm is being sold at unregulated prices, 50% by Gazprom and 50% by independent producers, is an important step towards more market based pricing in Russia's domestic gas market. Prices on the gas exchange have been as high[15] as USD 2.48/MBtu (USD 94/1 000 m^3) compared to regulated gas prices of about USD 1.06/MBtu (USD 40/1 000 m^3). As in IEA Europe, we believe that there are considerable benefits to gas exchanges which allow price transparency according to economic factors. Russia is making progress in improving gas sector regulation for market participants and working on installing a more effective balancing regime. Improvement of modified entry/

15. Gas was traded at USD 2.48/MBtu (USD 94/1 000m^3) on December 15, 2006.

Figure 40 **Gas price rises in selected Russian export markets**



Source: Press statements, Gazprom website.

exit schemes and balancing regimes is an ongoing challenge in many IEA European gas markets (see separate section on Investment and regulation).

We see domestic price rises as essential to stimulate more efficient consumption of gas in Russia, notably in the power sector. We therefore welcome Russian initiatives to raise the price of gas in the regulated sector and to expand the gas exchange. However, we are mindful that a focus on price rises alone may simply result in increasing non-payment if they are implemented without other policy remedies.

Foreign price reform

Shifting geopolitics have enabled Gazprom to take a proactive stance regarding price reform in some of the Russian "near abroad" as Russia's former Soviet neighbours are known. Gazprom has recently enacted a policy of raising prices in the near abroad with a view to bringing them to European market based levels as quickly as possible. As the price increases in these countries are more extreme than in the case of Russian domestic price reform, these dramatic rises in prices are likely to result in increased unpaid bills from customers. These accumulating debts have been used in the past by Gazprom to secure equity positions in customers' gas infrastructure.

Ukraine, for example is one of the most energy intensive countries in the world, with demand of some 80 bcm per year of gas. In 2004, Ukraine paid amongst the lowest prices of any of the "near abroad" (see Figure 40) and so Gazprom was perhaps overly keen to see demand reduction coupled with energy saving in this market. The recent price rises to USD 3.43/MBtu (USD 130/1 000 m^3) appear to be having an effect on consumption in the commercial sector, despite worries over non-payment. According to preliminary data, in 2006 domestic gas consumption was 65.87 bcm, a "saving" of 3.03 bcm on demand in 2005 despite the considerably colder winter in 2006. If Gazprom can continue to "save gas" abroad and increase its revenues at the same time, it may be in a position to cover some slippage in upstream project development.

Fuel switching

Short-term fuel switching is a good way of managing gas demand tensions in the short-term and is therefore used as a management tool by many IEA governments (see separate section on Gas Security). However, systemic gas substitution in the power sector has been a stated strategic aim of the Russian government for some time, especially given that almost 45% of power generated in Russia comes from gas. Despite the governments strategic aim, we note that gas demand in the power sector has risen year on year for the past ten years and that the share of gas in power generation has remained static in that time, if not increasing slightly.

In IEA countries, market forces have traditionally been relied upon to ensure

Box 3 ***Fuel switching in Russia during extreme cold***

In late January and early February 2006, extreme cold weather forced electricity utilities to switch their fuel source due to lower gas deliveries. Amid the record low temperatures in the European part of Russia and Europe itself, Gazprom cut its gas supplies by 12.5% effective 17 January 2006. At the same time, electricity consumption in the European part of Russia exceeded the target set by the Federal Tariff Service of Russia by 12.6%. Electricity generation from thermal power plants rose by 16.9% and heat output increased by 22.0%. Gas deliveries to power plants were restricted significantly in some areas of Russia: 51%-83% in the North-West, 48%-72% in the Middle Volga area and 35%-80% in the Centre.

In order to meet the increased electricity and heat demand, power plants switched to alternative fuels, fuel oil and coal.

The daily average fuel oil consumption by the power plants located in the European part of Russia grew 12-fold in the second half of January 2006 compared to the targeted consumption level. Total fuel oil consumption in January 2006 increased by 1.1 million tonnes. Fuel oil inventories, which in some cases declined below the allowable levels, had to be replenished amid surging fuel oil prices.

The coal consumption in the European part of Russia in the second half of January 2006 rose to 240% of the planned level, with the coal consumption in January 2006 exceeding the monthly target by 2.7 million tonnes.

Source: RAO UES, extract from Annual Report 2005.

that countries have efficient and well diversified portfolios of electricity generation. In Russia however, gas prices are similar to coal prices for large users, despite the considerable technical and environmental advantages that gas enjoys as a fuel. From a producer perspective, the cost to produce and transport one unit of energy as coal is far lower than the cost to produce and transport the same energy in the form of natural gas. The low regulated price of gas compared to oil has meant that gas has been the economic fuel of choice for power generators and large users. As has been experienced by some IEA countries, it is difficult to ensure that power generation companies make balanced decisions between economics and security of supply if prices for one fuel are so low.

Gazprom has taken a pro-active view of relative energy prices in Russia with its merger with Suek, the national coal company, and its takeover of the former oil company Rosneft. Regardless of the external "market" situation in Russia, Gazprom is now in a position to directly influence the energy balances across sectors. If it feels that gas production growth is not keeping up with demand for gas in the power sector, then it is in a position to influence the mix of fuels such as coal, through Suek, or oil through Gazpromneft.

The evolution of the Russian energy balance is of great interest to all observers. The "solution" found by Gazprom to the market failures or lack of progress towards market pricing to date in Russia is to push the market itself aside by internalising all the values and costs in one monopoly.

But if indeed Gazprom is worried that domestic gas consumption is rising too fast for projected production, it is possible that an increase in coal as a share of the domestic energy mix might be seen. Likewise pressure on the domestic gas market could be reduced by switching to oil in some plants, though we note that capacity is limited and oil is substantially more expensive than gas in Russia. In either event, the changing Russian fuel mix has the potential to affect global oil and coal markets, particularly Russian trade with Europe.

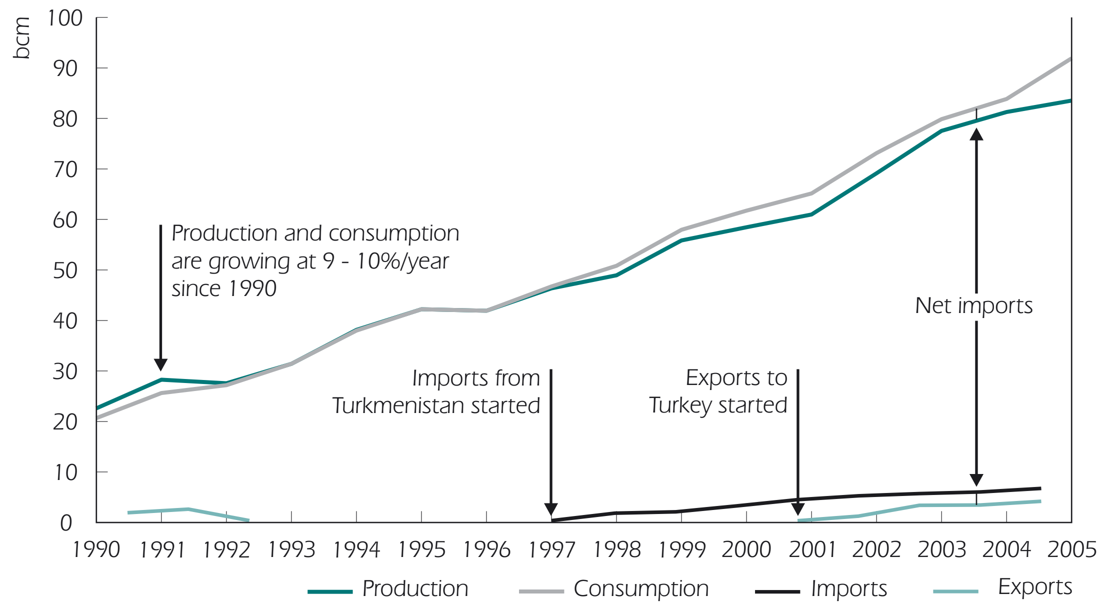
From the perspective of gas-importing countries it is perhaps comforting to see that measures have been taken to reduce gas demand in Russia in the medium term, or even in the short-term if needed. From a global/regional perspective however, it worth observing that ironically, the European drive for cleaner, less carbon-polluting natural gas looks likely to have the consequence of increasing coal- or oil-fired generation in Russia. Of course, this will be balanced by increased (premium priced) gas exports to Europe.

Islamic Republic of Iran

Iran, which has the second largest gas reserves in the world after Russia, is uniquely positioned in the global gas market, representing one of the largest potential new suppliers to both eastern and western markets, as Qatar does and Russia could potentially do with their huge gas reserves.

However, political uncertainty and commercial deadlocks have stopped attempts

Figure 41 **Iran's gas production, consumption, imports and exports**



Note: Consumption does not include re-injection into oil fields for enhanced oil recovery.
Source: *Natural Gas Information 2006*, IEA.

by the Islamic republic to monetize the giant gas reserves at its offshore South Pars field. The reserves are thought to belong to the same geological structure as Qatar's North Field, which has been a commercial source of LNG for the international market for more than ten years.

Iran is currently the largest producer and consumer of gas in the Middle East, with domestic consumption similar to that in the United Kingdom or Germany. Growth in consumption in the last two decades has been dramatic, running at 9-10% per year since 1990. The Iranian economy in general and power generation sector in particular are highly dependent on gas which accounts for more than 50% of primary energy supply and around three quarters of power generation.

Despite possessing the world's second largest reserves, Iran has been a net importer of natural gas since 1997. In 2005 it imported 7 bcm from Turkmenistan and exported 4 bcm to Turkey. Gas exports to Armenia are expected to start in 2007.

Introduction

While continuing to negotiate on numerous ambitious gas export projects, Iran's petroleum ministry faces calls from within the ministry and also from the Majlis, or parliament, to abandon such plans altogether and concentrate on using gas for oil field re-injection to boost oil production, especially under the current high oil price conditions. The Majlis also calls for gas to be used for the petrochemicals sector and other industrial, power generation, transportation and residential use within the country. Majlis Energy Committee Chairman Kamal Daneshyar said in September 2006 that gas volumes allocated by the National Iranian Oil Company (NIOC) for re-injection (30 bcm per year) into aging oilfields are insufficient. Commercial issues such as pricing and project ownership of gas export projects are also still complicated.

The election of Mahmoud Ahmadinejad as President of Iran in June 2005 has significant implications on the gas export plans. While the petroleum ministry and NIOC subsidiary National Iranian Gas Export Company (NIGEC) say they are committed to LNG, the opposing lobby wants more focus on meeting domestic needs first and using gas to increase oil production through re-injection, as well as using gas for petrochemicals and power generation. As oil exports account for up to 90% of total export earnings and nearly 50% of the government's budget, boosting oil production continues to be a high priority.

The petroleum ministry and NIGEC dispute this view, arguing that the country has plenty of gas to meet domestic requirements as well as for export. Based on analysis provided by NIOC, Iran will still have a massive 12 000 - 14 000 bcm (425-500 Tcf) left over for export after covering domestic needs and gas re-injection for 50 more years. The opposition lobby counters that any extra gas should be used to expand petrochemical and steel production for export, to diversify away from a heavily crude-export dependent economy.

In addition to economic and political pressure, there are other factors at play: over-stretched capabilities of domestic construction firms, which are already full with other projects in the oil, power and petrochemical sectors; also difficulties in securing experienced international engineering, procurement and construction contractors. Yet another factor is a dispute over the country's buy-back system.

The buy-back system

The buy-back system was introduced in order to reconcile the legal obstacles to foreign investment in the oil and gas sector with the need for foreign investment. Under the laws introduced after the 1979 Islamic revolution, foreign companies are not allowed to own, control, or even directly to invest in Iranian oil and gas fields. The 1987 Petroleum Law introduced short-term buy-back contracts between the ministry of petroleum or state owned companies and "local and foreign national persons and legal entities."

Under the terms of the contracts, foreign investors are required to undertake all upstream development and to bear the cost. They receive a fixed proportion of production, with a pre-agreed rate of return, but control of the fields in question reverts to the National Iranian Oil Company (NIOC) upon completion of the development.

The system is less attractive for foreign investors than traditional production sharing agreements or joint ventures. All buy-back contracts are as short as five to seven years, giving investors relatively little time to recover investment, especially when the foreign investors must finance all of the development costs. The lack of control over the pace of field development discourages investment.

In February 2007, NIOC indicated amended terms for buy-back contracts, with greater flexibility and an attractive rate of return: an extension of the terms of the contracts to 25-30 years; capital costs to be determined after front-end engineering rather than in the development plan, to enable more accurate project costing; the formation of a joint NIOC/contractor committee to oversee all phases of the contract, thereby allowing contractor involvement after project handover to NIOC; and a penalty and reward scheme to provide contractors with an incentive to maximize production. The rate of return has not been fixed in the revised terms, but would be suggested by the contractor as a first step towards reaching agreement between the parties.

Although some foreign companies have tried to invest in Iranian gas projects because of their huge potential, delays have been reported for both pipeline and LNG schemes that would be allocated gas from specific phases of the South Pars development.

Domestic supply projects

NIOC is keener to award new phases of South Pars that are geared toward supplying gas for domestic use. In 2006, a group of international companies, including Shell and Total, won qualification for South Pars Phases 19-22, a USD 5 billion project that calls for production of 40 bcm per year of gas and 160 000 b/d of condensate.

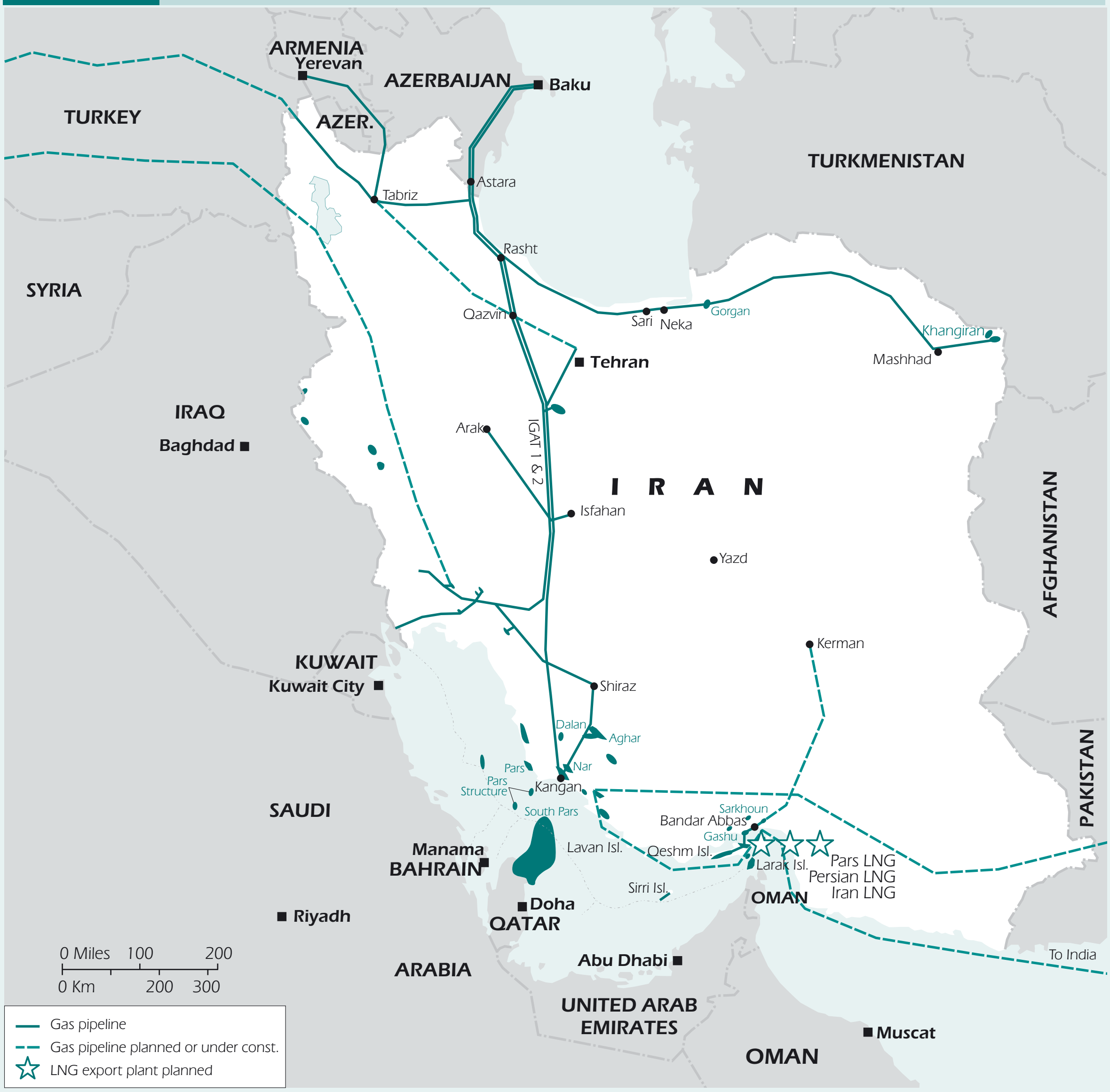
An important milestone for NIOC should have been the launch of South Pars Phases 6-8. These phases involve production of 30 bcm per year of gas and 120 000 b/d of condensate. Most of the gas was to be reinjected into the aged and ailing Aghajari oil field. Statoil won the operating rights of the development with a 40% interest in 2002 and was to operate the offshore portion. Production was expected to come on stream in mid-2006 but it has been delayed by a disagreement over the terms of the buy-back contract. Perversely, the disagreement has been caused by good news – a production upgrade from 10 bcm per year to 13 bcm per year. The better-than-expected performance of the wells led to conflict about the terms of the buy-back deal. As the pipeline and platform infrastructure has not been delivered as agreed, the three phases are now not expected to all come on stream by 2008.

Petrochemical sector: a huge gas user

The petrochemical industry in Iran and its feedstock requirement including natural gas are expected to grow quickly in the next decade, as the country tries to diversify away from the crude dependent economy. The first and also one of the biggest petrochemical plants in Iran (Shiraz) began operations in 1959, followed by the Kharg Island petrochemical complex in 1966 and Razi and Bandar Imam Petrochemical Complex and some others before the 1979 Islamic revolution.

Both production and investments in the petrochemical industry in Iran have grown significantly in recent years. In 1995, petrochemical production was 8.7 million

Figure 42 Iran's gas system



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source:The Petroleum Economist Ltd.

tonnes. Petrochemical production at National Iranian Petrochemical Company (NIPC) increased at an average annual rate of 6% during the period 1995-2005 and reached 23.6 million tonnes in 2006. The country is currently constructing massive new petrochemical production capacity which is approximately the combined current ethylene capacity of Japan, Korea, Chinese Taipei and China.

With the commencement of the South Pars gas fields development in 2001, NIPC started planning for mega gas-based petrochemical plants, many of which came online from 2003 to 2006. As such, this period saw an average annual growth rate of approximately 30% in production capacity. In 2006, 78% of total petrochemical production was exported, bringing in revenue of USD 3 billion (second only to USD 50 billion in crude export revenue). The Ministry of Petroleum and NIPC have introduced measures to package long-term investments more attractively for international companies. To encourage both domestic and foreign investors in the sector, Iran has provided tax holidays for the petrochemical zones.

In 2005, the petrochemical industry alone consumed around 8 bcm of fuel and feed gas, representing about 10% of the country's total gas consumption. Due to massive investment in polyethylene production, there is significant growth potential for gas demand within the country's petrochemical industry from 2007 to 2010. The country is also actively attracting foreign investors to invest in the industry, further emphasizing the significance of using energy resources domestically.

Pipeline exports

Currently, Iran has only a 10 bcm per year export contract with Turkey, which has not delivered full contractual quantities since inception. This has not prevented the National Iranian Gas Exporting Company (NIGEC) from planning several more export pipelines. While gas prices in the region remain significantly lower than international markets, NIGEC continues to negotiate gas exports, although many face considerable uncertainty. Iran's possible pipeline export projects are summarised in Table 24.

Table 24 Iran's pipeline export projects

Direction	Buyer	Start	Yearly volume
South	UAE Crescent	2007	5 bcm
	UAE DUSUP	n.a.	7 bcm
	UAE Mubadala	n.a.	10 bcm
	UAE Ras-Al-Khaimah	n.a.	6 bcm
	Kuwait	n.a.	3 bcm
	Oman	n.a.	25 bcm
East	Pakistan-India	2012+	40 - 80 bcm
North	Azerbaijan (Nakhjavan swap)	2005	0.35 bcm
	Armenia	2007	2.80 bcm
	Austria (Nabucco)	2012+	12 bcm
	Switzerland (Nabucco)	2012+	5 bcm
	Europe via Ukraine	n.a.	30 bcm
	Turkey	2001	10 bcm

n.a.: not available.
Source: Company announcements.

Many of these plans are discussed in other sections of the Natural Gas Market Review 2007 and have therefore been briefly summarised here.

Iran – Pakistan – India. The Iran-Pakistan-India (IPI) pipeline (or "Peace Pipeline") is a planned export route for Iranian gas eastwards. The USD 8 billion pipeline is expected to have capacity of 40 - 80 bcm per year, with India buying about two-thirds of the gas and Pakistan taking the remaining third. The gas would originate from the Iranian port city of Assaluyeh, the landfall point of gas produced in the giant South Pars field. For more information see later section on India.

The National Iranian Gas Company (NIGC) has a contract with Turkey's BOTAS Company to export 10 bcm per year via pipeline for 22 years (starting at 3 bcm per year in 2001, reaching the plateau level by 2007). After a cold winter 2006/7 in Iran, the exports faltered and Turkey (as well as many Iranian cities) saw their gas supply interrupted. Iran has also been mentioned as a potential source for the Nabucco project. This project is intended to link Turkey with Austria via Romania, Bulgaria and Hungary. For more information see later section on Turkey,

Various pipeline options are available to the south of Iran, in the Middle East and North Africa (MENA). These projects include United Arab Emirates (UAE), Kuwait and Oman. For more information see latter section on "MENA".

LNG projects

There have been a number of LNG project proposals in Iran since the 1980's, none of which have progressed to final investment decision. There is considerable uncertainty due to the internal divisions on how to best monetize and utilize the huge gas resources in the country, as well as political uncertainty surrounding the country. This means that getting the various proposals to the construction stage will continue to be tough. Among the various projects, Pars LNG looks most advanced.

Pars LNG (South Pars 11)

NIOC (50%), French Total (30%) and Malaysian Petronas (20%). In 2005 the project partners signed a framework agreement to produce some 13.6 bcm per year (10 mtpa) of LNG. Technip and JGC undertook front-end engineering and design work on the two-train plant. Although it has been revealed that the project's target start-up slipped from 2010 to 2011, volumes from Pars LNG have been aggressively marketed in China and Thailand, with a preliminary sales agreement for 8.2 bcm per year (6 mtpa) signed in 2006. Gaz de France (GdF) and Germany's E.On are also said to be interested in buying output from the project.

Persian LNG (South Pars 13-14)

Talks were started in 2001 on Persian LNG, another NIOC-led (50%) joint venture that has Royal Dutch Shell (25%) and Repsol YPF (25%) as foreign partners for two 5.4 bcm per year (4 mtpa) trains. In January 2007, NIOC signed an upstream service agreement with Shell and Repsol for development of Phases 13 and 14 (formerly 13a), which is subject to the final investment decision of the LNG development. NIOC says the final investment decision is scheduled for 2007.

Iran LNG (South Pars 12)

A 25-year deal was signed in summer 2005 for a group of Indian state companies (GAIL/IOC/ONGC) to buy 6.8 bcm per year (5 mtpa) of Iranian LNG starting in 2009 at a maximum price of USD 3.25/MBtu (a fixed price component of USD 1.2/MBtu plus 6.5% of the current Brent oil price in USD per barrel, which was capped at USD 31) on a free-on-board (FOB) basis. However, Iran later called for the price to be raised because of the subsequent rise in crude oil prices as Iran's Supreme Economic Council refused to approve the agreement.

Iran's oil ministry earmarked India to be the market for the 100% NIOC LNG (the current Iran LNG) project that aims to export up to 12.2 bcm per year (9 mtpa) of LNG from Bandar Tombak on the Gulf, fed by Phase 12 of the South Pars field development. In February 2007, Korea's Daelim and Iran's Khatam Anbia construction company were awarded a USD 500 million downstream contract for the project. Details of the deal are not clear. Iran is demanding an FOB LNG base price of USD 5.10/MBtu, nearly 60% more than the base agreed in 2005. China's Sinopec signed a memorandum of understanding to buy 13.6 bcm per year (10 mtpa) of LNG from this project in January 2005.

Chinese interest

In addition to the above-mentioned Chinese deals with Pars LNG and Iran LNG; NIOC and China National Offshore Oil Corp. (CNOOC) in November 2006 signed a USD 16 billion deal to develop Iran's North Pars gas field and build LNG facilities. The project would be undertaken in four phases. Gas from three phases would be used to produce LNG for export, with Iran taking LNG from one phase and CNOOC taking LNG from two phases. Gas from the fourth phase would be used for re-injection into oilfields and for delivery to the domestic gas grid.

Table 25 **Iran's LNG projects**

Project	Sponsors	Start	Potential buyers	Feedgas
Pars LNG	NIOC (50%), Total (30%), Petronas (20%)	2011+	T1: Total/Petronas equity lifting T2: Thailand (PTT), China (PetroChina), possibly India (GdF-Petronet), possibly E.On	South Pars 11
Persian LNG	NIOC (50%), Shell (25%), Repsol (25%)	2012+	T1: Shell/Repsol equity lifting T2: Asia (Japan)	South Pars 13-14
Iran LNG	National Iranian Oil Co. (NIOC)	2012+	India (Gail, IOC, BPC) China Sinopec (Yadavaran package)	South Pars 12
Unnamed	NIOC, CNPC	2014+	China (CNPC) LNG + domestic	Former South Pars 14
Qeshm	NIOC, LNG Ltd. (Australia)	2014+	tbd	Selkh, Southern Gesho
Unnamed	NIOC, CNOOC	n.a.	China (CNOOC)	North Pars
Unnamed	NIOC, SKS (Malaysia)	n.a.	tbd	Golshan, Ferdos

t.b.d: to be decided, n.a.: not available
Source: Company announcements.

China National Petroleum Corp. (CNPC) is also reportedly finalising its memorandum of understanding with NIOC to jointly develop a USD 3.6 billion upstream and LNG project based on gas reserves formerly known as South Pars Phase 14. The development would be expected to take seven years, with USD 1.8 billion being spent on developing 370 bcm of gas reserves and USD 1.8 billion on building an LNG export plant with 6.1 bcm per year (4.5 mtpa) capacity. This phase was earlier allocated for a gas-to-liquids (GTL) project.

None of the Chinese deals seems likely to yield gas deliveries before 2014.

Middle East and North Africa (MENA)

The Middle East and North Africa region is seeing rapid gas production growth, with new investment and ample reserves providing a basis for continued annual growth in the 6-8% per year range. Export growth has also been rapid, giving the region around a sixth of the world market. Further growth will be led by Algeria and Qatar in the medium-term, with Iran's emergence tentatively previewed beyond that.

However, rapidly rising domestic demand is proving a competing draw on resources, such that difficult decisions will need to be made in a number of Middle Eastern states about medium to long-term gas allocations, potentially resulting in the cancellation of some export projects. This means that exports are unlikely to keep pace with production in the longer-term, as the rewards of world market prices are balanced against the higher financial rewards of oilfield re-injection and the economic and social benefits of domestic gas-fired power generation and industry.

Strongly competing demands on the region's natural gas are likely to help foster market opening, providing some opportunities for outside investors. Equally, regional state companies are expected to use access to gas and long-term supplies to leverage opportunities in consuming markets.

Summary

The MENA region is one of the fastest expanding gas producing areas of the world, with regional growth of 6.4% in the period 2000-2005, compared to total non-OECD growth of 4.4% and OECD growth of less than 0.1% in the same period. That has almost doubled the region's share in world production to 15.5% in 2005, from 7.8% in 1990.

At the forefront of this expansion have been Egypt, Libya, Iran, Oman, Qatar and Saudi Arabia, with all bar Saudi and Iran also contributing to the region's expanding net export profile. This took the MENA share of world gas exports to 16% in 2005, equivalent to early 150 bcm of gas. New developments in Qatar and Algeria are expected to drive expansion to 2011 (see table), although Qatar's moratorium on new gas projects until 2009 will see at least a 3-year delay in large new supplies to the market. It is at this point that Iran's emergence as a net exporter might be felt, although the volume and timing of

Table 26 MENA natural gas export projects to 2015

Year	Country	Project	Gas volume/year	Target markets
2007 C	Qatar	Dolphin pipeline	20.7 bcm	United Arab Emirates (UAE), Oman
2007-08 P	Iran	Salman-UAE Pipeline	2-5.2 bcm	Sharjah/UAE
2008 C	Algeria	Transmed (Enrico Mattei) pipeline expansion	6.5 bcm on top of existing 27 bcm	Italy
2008 P	Egypt	Egypt-Israel Gas Pipeline	2 - 7 bcm	Israel
2008 *	Egypt	Arab Gas Pipeline Extension to Turkish Border	10 bcm	Jordan, Syria, Lebanon, Turkey. Potential to link into Europe.
2008-9 C	Qatar	Qatargas II	21.2 bcm / 2 X 7.8 million tonnes	The United Kingdom /Europe
2008-9 C	Qatar	RasGas III	21.2 bcm / 2 X 7.8 million tonnes	The United States, Chinese Taipei
2008-9 C	Yemen	Yemen LNG	9.2 bcm / 2 x 3.4 million tonnes	The United States, Mexico, Korea
2009 P	Algeria	Medgaz	8 Bcm	Spain/Europe
2009 C	Qatar	Qatargas III	10.6 bcm / 7.8 million tonnes	LNG - the United States
2009+ P	Algeria	El-Andalus LNG	5.4 bcm / 4 million tonnes	LNG
2010 C	Qatar	Qatargas IV	10.6 bcm / 7.8 million tonnes	LNG - the United States
2010+ P	Algeria	Skikda replacement LNG	6.1 bcm / 4.5 million tonnes	LNG
2011 P	Algeria	Galsi pipeline	8 -10 bcm	Italy/Europe
2011+(p)	Iran	Pars LNG	13.6 bcm / 2 x 5 million tonnes	LNG - Thailand, China
2012+ (p)	Iran	Persian LNG	21.8 bcm / 2 x 8 million tonnes	LNG - Asia, Europe
2012+ *	Iran	Iran- Pakistan- India pipeline	40 – 80 bcm	Pakistan, India
2012+ (p)	Iran	Iran LNG	12.2 bcm / 2 x 4.5 million tonnes	LNG – Asia
2014+ *	Iran	Qeshm LNG	5.9 bcm / 3 x 1.45 million tonnes	LNG
2015 **	Iran	Nabucco Link in	10-12 bcm	Central Europe

Under Construction (C), Planned (P) and Proposed (*)
Note: further details in separate LNG section.
Sources: Company reports, statements, news reports.

any tradable gas remains the subject of considerable speculation (as noted in the previous section on Iran).

Consumption

One of the most significant developments of the last year has been the increasing profile of the region's own domestic gas requirements, whether for power generation, gas-based industry or oilfield re-injection, all of which offer alternatives to overseas sales. Consumption in the Middle East and North Africa states as a whole is expanding at some 7.4% a year, compared with world demand growth of

2.6%. This gave the region an 11% share of global demand in 2005 from 6% in 1990. It is notable that the region's largest producers, Egypt, Iran, Qatar and Saudi Arabia have charted some of the fastest demand growth.

This reflects in part the widespread adoption of gas-based industrialization strategies to reduce economic dependence on oil. It is also the consequence of a region-wide "switch" to natural gas in the energy mix, most notably for power generation and water desalination, where demand for gas is expanding in excess of 10% a year, over twice the OECD and non-OECD averages. Even further growth will be charted as a result of the increasing role of gas in the energy mix, such that 59% of the region's installed capacity will be derived from gas in 2020, from around 52% in 2003. Gas demand for power generation accounts for more than 40% of total gas consumption.

Exports

Although existing investments and planned projects point to continued growth in regional gas production at an annual range of 7-8%, availability for exports is unlikely to hold this pace. That the region will become an increasingly important source of new gas supplies to world markets is not in doubt. However, domestic demand growth is such that local users likely to become an increasing priority in the allocation of new gas feedstock in the 2008-15 period. This may have the effect of reining in contributions to world exports, but also brings with it the prospect of new investment opportunities in the region, many of which are likely to be open to foreign partners, given the limited experience of many regional state companies. Pricing remains a key issue here which will have repercussions on the pace and attractions of any such developments for the domestic market, with the region as a whole erring towards extensive under pricing for their own markets to sustain growth, this policy inevitably distorts economics over the longer term.

With competing calls on finite resources, greater efforts are expected on the part of consuming states in order to tie up available MENA supplies for long-term needs. This may also conversely create investment openings for producer state companies to enter the mid and downstream value chain in a more significant way as part of tie-ins with gas (and oil) supplies. MENA suppliers are likely to gain further benefit from their increasing importance as a strategic counterweight to Russian gas in European markets. This has already meant EU political backing for a number of pipeline initiatives from the MENA region, with Algeria the principal focus of this to date.

The full policy implications of the rapid growth in consumption rates in MENA states (especially the Gulf) are still very much in the process of being assessed. This means that it will take time before the precise impact on the regional project outlook becomes clear. However, the initial signs are that some changes in energy and wider economic planning will be required to manage usage in the mid-term, with the potential for feedstock substitution where possible and the scaling down or cancellation of projects plans where not. Initial signs are that these cutbacks will be focused on industrial projects for the domestic market. This in turn has implications for alternative energy sources like oil products, in the event that feedstock substitution strategies are pursued.

Oman

Among states where shortfalls have been felt or are anticipated, Oman has been one of the most candid. In February 2007, Undersecretary of Oil and Gas Nasir al-Jashmi, acknowledged that “we have a lot of demand and there are projects in the pipeline that we cannot meet” in comments to the Middle East Economic Survey. Oman estimates that gas demand will reach 39 bcm per year in 2010, compared with production of 28 bcm per year. The lack of near-term availability has already meant delays to full capacity production at the Qalhat LNG project, which is now envisaged for 2009 after start-up at the end of 2005. It also rules out any further Omani export initiatives without the benefit of new supplies, either from domestic discoveries or imports. Nevertheless, the Omanis have indicated that the brunt of any shortfalls will be felt by new domestic projects, whether for power generation or for petrochemicals. In this light, the country’s lead developer, Petroleum Development of Oman, is considering coal for a new 500 MW generation facility, rather than natural gas, while the Duqum petrochemical and refining project is being reviewed on the basis of oil feedstock, rather than natural gas. The Sohar petrochemicals project is also under review and has been set back from its initial start-up date of 2009. Although the situation will be eased somewhat by imports from Qatar in 2008, (and the end of Omani commitments to Dolphin) these supplies will be focused on oilfield re-injection at Mukhaizna. This leaves Oman to make further amendments to the gas-based industrialization at the core of its ambitious Vision 2020 economic programme, with the aim of compensating for the shortfall in near and mid-term gas.

United Arab Emirates (UAE)

In the UAE, power/desalination demand and oilfield re-injection are the two principal drivers of demand growth. Some near-term relief is promised by the arrival of Qatari gas through the Dolphin pipeline in mid-2007, but this is still expected to fall short of demand. Meanwhile existing domestic developments are largely geared towards oilfield reinjection, as part of plans to boost production capacity to 3.7 - 4 mb/d from current levels of 2.8 mb/d. Development of more inaccessible domestic reserves and further imports from neighbours like Iran and Qatar, are all under consideration in this light. However, the decision by the region’s largest exporter, Qatar, to extend the assessment of its North Field reservoirs until at least 2009 means that new gas from this source to the UAE and other would-be regional importers, remains unlikely until at least 2012. This will contribute to the pressure on the UAE and others to seek out alternatives for the medium-term, particularly for gas-intensive projects such as the two aluminium smelters under consideration and petrochemicals expansion at Borouge.

Iran

As mentioned in the previous section focusing on Iran, the country is also facing a similar scenario despite holding the world’s second largest conventional gas reserves. Its domestic demand growth is estimated at just under 10% a year, only held back from higher growth rates by the lack of distribution infrastructure and upstream availability.

Elsewhere in the Middle East

Both Saudi Arabia and Kuwait are also facing gas shortages, as a result of allocations for power generation projects and in the former, petrochemicals. There has always been considerable interest in Saudi Arabia as a potential net gas exporter from the region given the size of its reserve base. However, unconfirmed reports suggest that near and mid-term gas availability even for domestic uses is tight. This has had the impact of delaying supplies of feedstock for planned petrochemical projects and may cause future project plans to be revised. Saudi Arabia has also reverted to the use of oil products for some new power generation, rather than natural gas, in contrast to previous policies favouring natural gas as a means of displacing oil use. In this light, the planned independent water and power project at Ras al-Zour, is now expected to run on more expensive oil feedstock. Similarly in Kuwait, plans to construct a fourth refinery at al-Zour have largely been driven by domestic power generation needs, after difficulties in locating domestic or imported gas supplies for planned gas-fired power projects at al-Zour, Shuaiba and Subiya.

Egypt

Egypt has witnessed the most rapid domestic demand growth of all MENA countries, some 10.8% a year over the period 2000-05. Despite its more conservative approach to gas exports, whereby only one third of reserves is available to the export markets, there are signs that it too is struggling with contending demands on its gas. In the home market this is led by domestic petrochemicals, power generation and efforts to extend residential usage through a national gas grid. In the export market, this includes commitments to the 10 bcm Arab gas pipeline running through Jordan, Syria and eventually Turkey; the pipeline to Israel; and two LNG plants at Damietta and Idku, which are also in need of new gas for expansion. Egypt is already importing fuel oil for domestic power generation, at some cost, and in this atmosphere, further commitments of gas to export markets will be politically and economically difficult without substantial production increases.

Algeria

Algeria accounts for almost half MENA gas exports. Algeria has seen its export initiatives given enhanced status in EU energy planning, which is set to result in a memorandum of understanding on energy cooperation in 2007, along the lines of similar agreements with Kazakhstan, Azerbaijan and Ukraine. For its part, Algeria has agreed to expedite work on two further EU-bound export projects, including the Medgaz link to Spain, due in 2009 and the Galsi link to Italy, which is due in 2011, along with the expansion of the existing Trans-Mediterranean link to Italy. This will offer a further 22.5 bcm of Algerian gas to Europe by 2011, up from nearly 70 bcm total exports in 2005.

However, there have been some signs of tension in this emerging energy inter-dependence, particularly after Algeria's state-owned Sonatrach signed an MoU with Russia's Gazprom in mid-2006 on future energy cooperation. The link-up between leading suppliers was particularly sensitive for Italy, which depends on Russia and Algeria for 69% of its imports in 2005 and was therefore sensitive to any hint of collaboration between the two. For its part, Algeria has stated that the Gazprom MoU is similar in scope to those signed with Shell, BP and Norway's mostly state-owned Statoil. However, strong reservations have also been expressed in Spain.

Algeria and other suppliers also concerned about over-reliance on one single market and are eager to increase investments through the supply chain in order to mitigate risk and reap some of the rewards of integrated supply chain management. For Algeria, this has taken the form of the pursuit of access to mid and downstream investment opportunities in EU markets. In this light, it has plans to establish marketing companies in Italy and France, as well as establish minority stakes in regasification facilities. To date, Sonatrach has interests in regasification in the United Kingdom, France and Spain and is also pursuing regasification and marketing opportunities in Italy. This trend is likely to continue as both sides of the supply picture seek to mitigate concerns about market security and producer National Oil Companies have the capital available from high energy prices to pursue such investments.

Spain's stated policy is to limit supplies from any one country to 60% of imports. In the context of its own national market, Spain was close to this limit in 2005, although dependence was reduced to 43% in 2006. This limit makes it difficult for Spain to encourage an expansion of gas imports from Algeria which would otherwise be beneficial for security and competition in the wider European market. Indeed, if there were a fully integrated European gas market, total dependence on Algeria would be less than one quarter of imports. This is a good example of where both Spain and Algeria could achieve greater diversification and security through greater integration of the EU gas market.

Libya

Libya too has continued efforts to increase exploration through its open tender licensing process, with a number of gas prone blocks including Mediterranean offshore acreage made available in the third international licensing round in 2006-07. It has plans for a further licensing round focusing on gas in 2007. However, as yet, there is no additional availability to increase capacity at the 8 bcm per year Green Stream pipeline to Italy or indeed feed into new export projects. Shell is however working on the project to upgrade the al-Brega LNG plant, which could include an expansion to 4.3 bcm per year (3.2 mtpa) from 1 bcm per year (0.8 mtpa), although this remains dependent on exploration success. A number of other companies, including BP, are also discussing integrated gas ventures.

Investment

There are, however, some positive signs emerging from the region that the demand for gas, whether from domestic or overseas sources, will help create a more vibrant project climate, both because of the strength of demand and the requirement for external expertise to meet the pace and complexity of requirements. In some cases, this is taking place through the redesignation or reconfiguration of projects, such as the Palm GTL project in Qatar, where the GTL aspects have now been abandoned in favour of a domestic-focused development project, known as Barzan, in which Exxon Mobil, will take a 10% stake. Perhaps more significantly, there are signs that gas demand is generating rare openings for upstream investment and engineering support, a trend which is likely to continue while international prices for gas remain at current high levels. This impulse is supported by the relative lack of gas experience held by the region's mainly oil-focused state-owned companies, as well as the need for investment funds and technological input in cases where reserves are hard to access and where a sense of urgency is at play.

Oman has again been the most pro-active Gulf player to date, awarding its first two onshore gas production sharing agreements in 2006. The awards have ushered new players into the country's upstream arena, with BG marking its first entry with the Abu Mutabul Block 60 award, while BP was awarded development rights to tight gas reserves at Khazzan-Makarem. Oman estimates it has between 20 to 60 Tcf of gas locked up in tight geological formations, which were previously deemed as uncommercial. However, rising prices, strong demand, not to mention technical advances, have changed assessments on this, with some hope that tight gas supplies will provide the country with a longer-lifespan than conventional reserves.

So too in the United Arab Emirates (UAE), where Abu Dhabi has started an award process to develop reserves that were previously deemed as uncommercial due to their high sulphur content and relative inaccessibility. Prequalification for the development of a small part of the country's 5 663 bcm (200 Tcf) plus of sour gas reserves was started in 2006, drawing in a number of major international players. An award on this is expected in 2007, allowing project completion by around 2011-12. Foreign players will be given a 40% stake in the projects under 30-year contracts with the Abu Dhabi National Oil Company.

Further such opportunities are also expected in other regional states, including Kuwait, where a non-associated gas find in 2006 was estimated to hold some 35 Tcf (991 bcm) of reserves. The KPC has moved quickly to draw up a fast-track commercialization plan for the field, which is due to be published in 2007. Expectations are for initial production of 4.5-5 mcm per day (1.7 - 1.9 bcm per year) from the North Field find, with a further 17 mcm per day (6.2 bcm per year) also planned from the Durra gas field in the offshore Gulf. The latter development awaits the resolution of a maritime border dispute with Iran. It is also worth noting that it was the allure of natural gas production that broke the mould on foreign participation in the Saudi upstream industry in 2003-04 when its initial Empty Quarter tender was concluded. As yet, exploration for gas outside these four PSAs is being led by Saudi Aramco. Seismic work in the Red Sea area, which was initially offered to investors under the abandoned Strategic Gas Initiative has also been undertaken in the last year. This, along with growing interest in Gulf offshore reserves, may provide the basis for future licensing rounds in the country.

Elsewhere in the region, progress in bringing new gas investments to the market has been mixed. In Iran, political changes and subsequent policy reviews have upset the momentum of project awards at South Pars, with the effect that new awards have dried up in the last 18 months. A restart is envisaged in the project process, although the country's international position, combined with an increasing preference for domestic players means that opportunities for investments will be more limited. Algeria too has stepped away from the international fray in 2005-06, in order to reconsider changes in its hydrocarbon legislation. The resolution of this debate in early 2007 is likely to pave the way for a return to the market this year, albeit on less favourable terms than originally envisaged. In all of this, Egypt has remained a relatively steady presence in the regional project climate, offering at least one tender of gas exploration acreage a year, with a positive investor response up until the latest round (see below).

Pricing

However, while investment opportunities may have started emerging in response to demand signals, it is clear that gas pricing for domestic projects in the region remains dislocated from international pricing and the global demand picture. This reflects the widespread provision of cheaply priced gas to encourage usage and foster gas-based industry, as well as an unwritten political contract between governments and populations in oil and gas rich states for cheap and abundant energy.

In some cases, external upstream investors are shielded from these lower prices by "cost plus" approaches to payment or condensate export rights which moderate exposure to the low domestic market rates. This leaves regional governments to bear the brunt of the burden between development or purchase costs and the domestic price base. However, the costs of this approach are rising in terms of lost revenues, decreased efficiency and an increasing subsidy burden, which has prompted domestic debate on the issue in a number of states. The most notable dialogue has been in Saudi Arabia and Iran where prices of USD 0.75/MBtu and USD 0.35/MBtu have been used as an incentive for downstream industry growth. Here, full market prices for domestic users remain unlikely given the developmental

Table 27 Reported domestic gas feedstock prices in selected MENA countries

Country	Domestic prices
Egypt	USD 1.19/MBtu
Iran	USD 0.35/MBtu
Oman	USD 0.80/MBtu
Saudi Arabia	USD 0.75/MBtu
UAE	USD 1/MBtu[16]

16. Reported for gas sale from Adnoc to Dubai Jebel Ali power station, APS Market Review, 15 January 2007.

and political objectives of subsidized gas, although incremental price increases represent a more probable outcome in order to help distinguish the merits of contending calls in the domestic market.

Until recently, Egypt was one of the few countries to pass on some of the burden of low domestic prices to investors, which proved acceptable in a lower price era, with some recompense available through access to export markets through LNG and pipeline gas. However, signs have increased over the last year that this policy was beginning to pose a disincentive to investment, such that interest in the 2006 EGAS licensing round fell far short of expectations. Investors such as BG and Apache also spoke publicly of the need for higher prices. This has persuaded the Egyptian government to make a deal with its largest oil and gas investor, BP, in 2007 which will see it pay a higher price for gas from the North Alexandria and West Mediterranean Deep Water concessions. The maximum price to BP is quoted at USD 4.7/MBtu, as opposed to a usual price of USD 2.65/MBtu, in recognition of the costs of development in deepwater offshore areas. This is likely to act as a benchmark for future such arrangements, helping to foster investment in the country's more resource-intensive development acreage and unlock gas for domestic and potentially, export markets, where reserves are sufficient. However, it is not yet clear if the Egyptian state will shoulder the burden of higher prices, or pass on part of the increase to domestic users who pay around USD 1.19/MBtu for gas, thereby contributing to an estimated USD 7 billion energy subsidy burden in 2006-07.

Exports to near neighbours previously used pricing formulas that were relatively favourable to buyers in the interests of bolstering regional relations and gaining market access. However, the signs are now that those with net gas to export will be unwilling to strike deals on the same terms, given the widening disparity with international prices. Qatar has now intimated to Oman and the UAE that it will be looking at a minimum of USD 4/MBtu for any second phase of supplies through the Dolphin pipeline, compared to prices of around USD 1.30/MBtu in the initial phase. A short-term bridging supply deal to Dubai in 2007, is estimated at three to four times the original price. Iran has gone one step further in attempting to renegotiate its 2001 supply deal with Sharjah based on a gas price of USD 0.46/MBtu (USD 17.5/1 000 m^3), which would have risen to a maximum of USD 1.06/MBtu (USD 40/1,000 m^3) in a second phase of development. Iran has also started initial discussions with Oman and Dubai (UAE) over future exports, where significantly higher prices are envisaged.

At the international level, MENA states have tended to fix prices at the prevailing world market levels under long-term contracts, except in a few exceptional cases where political or strategic considerations have resulted in more buyer-favourable arrangements. Qatar in particular has had sufficient new developments in the last year to take full benefit of the higher price climate. Iran is reported to be looking at a new maximum price of USD 5.10/MBtu for LNG sales to India, after pulling out of a 2005 agreement which capped prices at USD 3.25/MBtu based on a Brent crude cap of USD 31/bbl. It is also reportedly looking at a price of USD 4.93/MBtu for pipeline gas supplies to India and Pakistan based on 6.3% of the Japanese crude cocktail (JCC) (at USD 60/bbl) and a fixed component of USD 1.15/MBtu.

Central Asia

To complement established economic relations, Central Asian and Caucasian states as well as Russia are understandably seeking to diversify their energy sector investment and oil and gas export routes. With new independent oil export infrastructure from the region starting up successfully in 2006, (Baku-Tbilisi-Ceyhan pipeline), attention has shifted to possible gas export routes from the region to central, southern and western Europe.

In addition to the completed South Caucasus Pipeline, a number of alternative export routes are under active consideration. West-bound options include the Nabucco project, the Greece Turkey Italy inter-connector and the Trans Adriatic Pipeline as well as Trans Caspian options (see also Turkey section). East–bound options include routes to China and through Afghanistan and Pakistan to India.

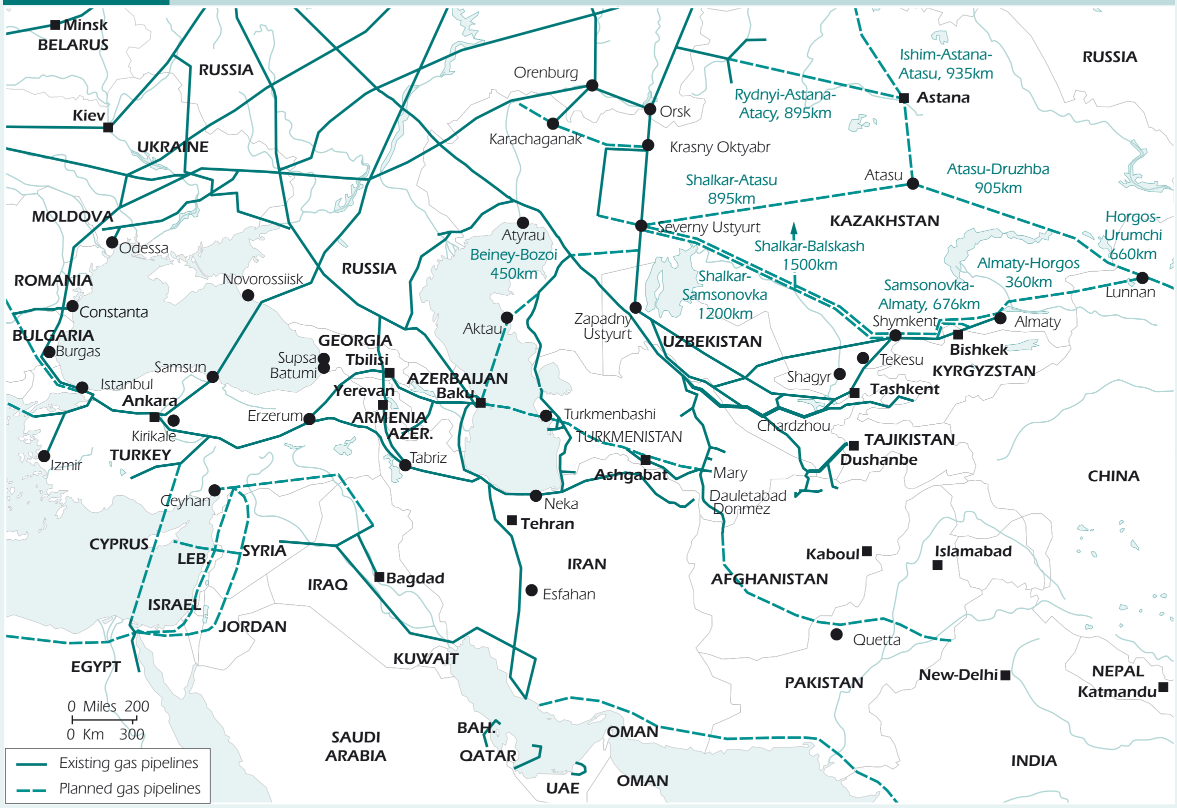
However, gas availability is a central issue. In the time-frame to 2012, gas from Azerbaijan could provide up to 15 bcm to a west-bound pipeline; supplies in excess of that would need to be sourced from new investment in Azeri prospects and in Turkmenistan and Kazakhstan. In addition, pipelines crossing up to eight international borders face major risks and will not proceed in the time frame to 2015 in the absence of significant political support. China is an alternative potential market for these producers, offering less of this type of risk. More transparency on infrastructure investment and what commercially exploit-able gas reserves will become available over time, accompanied by dialogue on the long-term export policies of Caspian gas producers, in both West and East-bound market perspectives, is urgently needed.

Central Asian and Caucasian States have strong links with the Russian Federation, including historic, economic and cultural ties, between what was until just 15 years ago part and parcel of a monolithic Soviet Union, preceded by the tsarist empire. Hence, engagement between Russia and Central Asian and Caucasian States has a long tradition, but is now evolving.

The newly independent Caspian and Central Asian states, that include the Russian Federation, are now seeking to diversify their energy export markets and transit routes and hence are fostering trade links with new demand centres not just in the west, but to the east and south.

Russia would like to retain newly independent Central Asian and South Caucasian states in its sphere of influence. It is driven by the desire to restore some degree of the status quo ante, recognising the finality of the demise of the Soviet Union. In the oil and gas sector the ability of Transneft and Gazprom to block Central Asian and South Caucasian access to European oil and gas markets through their control of the only available transit pipelines has been a key instrument. South Caucasian and Central Asia's policy towards Russia has been balanced by the fact that Russia provides a secure route to maket

Figure 43 Pipelines in Central Asia



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA.

for their oil and gas production even if at a discounted price, which was substantially increased in 2006, but still remains below market worth, (as defined by European net back prices), although higher than Russian internal gas prices.

The evolution in oil sector relations between Russian and Central Asian states and the south Caucasus shows that the near monopoly position of Transneft in Russia is increasingly offset by the opening of alternative routes to markets. The fungible nature of oil as a global commodity opens up more export modes when compared to gas. The Baku Tbilisi Ceyhan (BTC) pipeline entered into operation in summer 2006, exporting up to 1 mb/d of oil from the offshore Azeri Chirag Guneshli field. The subsequent agreement between Kazakhstan and Azerbaijan to commit additional Kazakh oil volumes for export through BTC via the Kazakh Caspian Transportation System could ultimately be in the range of 1 mb/d. These are pivotal events in tapping Central Asian hydrocarbon resources. Other export options have recently become available to Central Asian and Caspian oil producers such as the Atasu-Alashankou export link to China, rail transport or exports by barge to Caspian ports such as Neka in Iran, Baku in Azerbaijan and Machakala in Russia.

The gas sector is up against more difficult obstacles – many a result of its costlier and more rigid infrastructure. Russian resistance to allowing Central Asian and South Caucasian states to diversify investment and export routes is driven by the Russian state's interests in preserving and expanding Gazprom's monopoly over exports. Gazprom inherited the major part of the centralised Soviet Union's gas export system and is using this to assert as much control as possible upstream into producing countries of Central Asia. This approach is also being applied to parts of the gas transit system now in other countries formerly part of the Soviet Union (for example Belarus). Gazprom's focus on "reacquisition" of these transit pipelines is detracting from investments in the Russian upstream

The relationship between Russia and Central Asian gas producers, of which Turkmenistan is believed to have the largest gas potential, will shape the future of Caspian gas. Russia, given its past relationship with the region, may seek to delay any Trans Caspian gas export options that could link Central Asian

Box 4 *Central Asia's eastern ambitions*

Turkmenistan wants to develop alternative export routes independent of transit routes in Russia. Current lack of progress on Trans Caspian options has lead to a pipeline plan to China. China has aggressively pursued this possibility, especially given uncertainty regarding the availability of resources from Russia and Western China to fill the proposed second West-East pipeline.

In April 2006, then-President of Turkmenistan, Saparmurat Niyazov, signed an agreement in Beijing with Chinese President Hu Jintao under which China pledged to purchase 30 bcm per year of gas at the Turkmenistan border for 30 years, «starting from the date the Turkmenistan-China gas pipeline is commissioned in 2009.» The two governments agreed to build a gas pipeline between the two countries and jointly develop natural gas resources in the eastern area on the Amu Darya River.

CNPC is preparing for as much as 30 bcm per year supply starting in 2009 (or later), through a 3,000-km pipeline traversing Uzbekistan and Kazakhstan to connect to the West-East Pipeline in the Xinjiang Uygur Autonomous Region. As much as USD 13 billion would be invested to carry the gas at USD 1.2 - 1.5/MBtu.

Kazakhstan is conducting a feasibility study for a gas pipeline to China. According to state Kazmunaigaz, two routes are being evaluated: the southern line to go through consumption centers in the southern part of the country and the central line parallel to the existing crude pipeline. Kazmunaigaz said in Beijing in 2006 that Phase 1 construction of a 10 bcm per year pipeline to China would be undertaken jointly with CNPC for completion by 2009. Expansion to 30 bcm per year is targeted for completion by 2012. From the Chinese border, a spur would link the pipe to the West-East gas pipeline. The Turkmenistan – China and Kazakhstan – China pipelines could be combined into one.

production capacity through Southern Corridors directly to European demand centres, for example by supplying these markets directly from its own network, or contracting all available gas for export. In 2003, Gazprom contracted nearly all of the gas export potential of Turkmenistan and concluded similar strategic agreements with Kazakhstan and Uzbekistan. Including re-export to Ukraine (Turkmenistan's traditional export market) currently about 50 bcm of Central Asian gas is exported to Russia – equivalent to 8% of Russian indigenous production.

Russia recently agreed to raise gas prices to USD 2.64/MBtu (USD 100/1 000 m^3) for Central Asian gas whereas Russia is paid nearly USD 7.91/MBtu (USD 300/1 000 m^3) at Russian export points (including transit costs). For now, Belarus and Armenia purchase gas at a substantially lower prices. Though the price differential between the purchase price of Central Asian gas and European border prices thus remains the same for Gazprom, it has decreased imports from Turkmenistan from the originally 60-70 bcm agreed in 2003 to 50 bcm for 2007. It is not quite clear what led to this change in volume. On one hand this may have been a response to increasing gas prices; on the other hand it may reflect the current production and export limits in Turkmenistan due to investment constraints.

With gas prices in European markets rising recently (according to oil indexation) and given the potential for Central Asian gas reserves to service those markets, there is growing European interest in buying and shipping Central Asian gas by pipelines that do not cross Russia, but instead transit through Turkey (as discussed in the section on Turkey). However, in the past, neither Turkmenistan nor Uzbekistan has been a particularly hospitable environment for Western companies.

It is possible that the death of former Turkmen President Niyazov will provide an opportunity to re-open the possibility of westbound trans-Caspian gas. For the moment, only China and Iran offer direct export opportunities; there is considered to be enough reserves for more than these two markets would require, although transparency on these reserves is especially poor. East-bound options for gas export are attractive for Central Asian states to consider, even at a discounted price, because of the potentially large market size. Moreover, such options tend to improve the negotiating position of Central Asian gas producers with Russia. Another constraint which may be felt by companies of IEA member states is concern for their competitive position in Russia and whether Russian reaction to their Central Asian activities might impair their (admittedly limited) access to much larger upstream oil and gas assets in Russia, including offshore. Russia itself may be pondering the implications of opening east-bound opportunities for Caspian gas for its long term, privileged relationship with Central Asia and South Caucasian states. Despite precedents created by massive investment in subsea gas-links in the Black Sea (existing) and Baltic Sea (under construction) by Gazprom, Russia continues to raise Caspian Sea delimitation and environmental concerns about subsea gas pipelines as arguments against any Trans Caspian gas options.

In the meantime, Gazprom has continued the gas price rises seen in 2006 into 2007 for most FSU and former Soviet bloc countries, towards west European levels. Gas prices to Georgia have increased in the order of 400% in two years from an unsustainably low USD 1.32/MBtu (USD 50/1 000 m^3) to USD 6.07/MBtu (USD 230/ 1 000 m^3). Ukrainian price increases were at the heart of the interruption of supplies witnessed at the beginning of 2006, while prices to Belarus have been left in a transitional arrangement towards European levels (Figure 40).

The outcome of gas price negotiations between the State Oil and Gas Company of Azerbaijan and Gazprom of Russia in January 2007, may show the limits of Gazprom's negotiating strength. Here Azerbaijan chose not to accept the USD 6.07/MBtu (USD 230/1 000 m^3) price offered by Gazprom for the gas it proposed to sell Azerbaijan in 2007. The Azeris chose to rely on indigenous production comprising associated gas from Azeri Chirag Guneshli (at the expense of re-injection, slowing down oil output) and Shah Deniz volumes that would ramp up over the year, next to traditional onshore production. Azerbaijan has also switched to fuel oil power generation and delayed exports of gas to the Turkish market via the South Caucasus Pipeline. On the other hand this might be seen by Russia as a desirable outcome: locking up Azeri gas for domestic use and hence limiting its ability to compete with Russian gas in Europe.

People's Republic of China

Gas use in China is still small, currently only 3% of demand and likely to grow slowly to 4% by 2015. This corresponds to gas use growing from 47 bcm in 2004 to 69 bcm in 2010 and 96 bcm in 2015 (*WEO 2006*). By contrast, statements from the Chinese government and analysts indicate significantly higher hopes, ranging up to 190 bcm of consumption by 2015, based on estimates of domestic production of up to 120 bcm and optimistic assessments of LNG and pipeline imports. Up to now, most gas has been produced locally, but import infrastructure is being established rapidly as demand increases beyond domestic supply – echoing similar trends amongst IEA countries, though not necessarily for the same reasons.

China accepted its first LNG shipments in 2006 and a second terminal is well underway, while a third, in the Shanghai area, started construction recently. Although Chinese energy demand is growing rapidly with GDP, the presence of plentiful domestic coal supplies could indicate that gas use countrywide seems set to remain relatively small. Nevertheless, Shanghai in particular could be a substantial gas importer by 2015.

Shanghai and LNG

One important development in 2006 concerns a new LNG project into the Shanghai market. This area may have a significant influence on total Chinese gas demand, as well as the natural gas market in East Asia as a whole, largely because of its ability to compete for globally priced LNG supplies which may be too expensive

Figure 44 Gas infrastructure of China

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: The Petroleum Economist Ltd.

for other Chinese regions. It is also worth noting that the planned LNG receiving terminal in Shanghai is most likely to be the last one in China built before the end of this decade.

The Yangtze River Delta area surrounding Shanghai has a prodigious appetite for gas. Shanghai first started using natural gas from the offshore Pinghu field in 1999. In 2003, when the first eastern section of the 4 000 km West-East Pipeline was commissioned connecting the gas-rich Xinjiang Uygur Autonomous Region in northwest China to demand centres around Shanghai. At the time, the pipeline operator PetroChina was worried that the 12 bcm per year line would not be fully utilized for several years. After the pipeline was completed in 2004, however, the pipeline filled quickly but demand in the Shanghai area could have grown even faster. A 5 bcm per year expansion of the line itself is now underway.

According to a recently released energy white paper, Shanghai plans to more than double the ratio of natural gas in its energy consumption by 2010, with imported LNG playing a key role in achieving the goal (the municipality based the white paper on policies in China's 11th Five-Year Plan, 2006 - 2010). By 2010, Shanghai plans to have gas accounting for 7% of its primary energy mix, up from 3 % in 2005. The city also hopes to cut its coal dependence to 46% by 2010, from 53% in 2005.

In August 2006, Shanghai LNG Co., Ltd., a joint venture between Shanghai municipal utility Shenergy (51%) and CNOOC (49%), awarded the terminal's main cons-truction contract to a consortium led by Ishikawajima-

Harima Heavy Industries (IHI) of Japan. The contract of about USD 260 million consists of several components, with the Japanese company responsible for the facility's three 165 000 cubic meter storage tanks and a venture comprising Chinese Taipei's CTCI Corporation and local Chinese firm Wuhan Engineering Co., Ltd. (WEC) handling the site preparation, the marine facilities, the regasification equipment and other related infrastructure.

CNOOC continues to consolidate its position as China's No. 1 LNG importer, while trailing the other two national giants PetroChina and Sinopec in domestic gas production. It forged ahead with the third facility at Shanghai, after starting operations in the country's first terminal in Guangdong in the summer of 2006. Its second terminal in Fujian is under construction and is due to start receiving LNG in 2008. The Shanghai terminal, strongly supported by the local government who wants to cut air pollution, will have an import capacity of some 4 bcm per year. Construction started at the beginning of 2007 for completion in summer 2009. The regasified LNG would be primarily supplied to power generation plants planned by Shanghai City (3.6 GW in total).

LNG for the facility is to come from Malaysia's Petronas. The Shanghai LNG deal with Petronas was the first LNG supply agreement signed by China since 2002. Rising global LNG prices had made deals difficult for other Chinese markets in which the gas prices have been fixed. It is to pay USD 5.6 - 5.8/MBtu FOB at a USD 60/bbl oil price, according to a senior official at the National Development and Reform Commission (NDRC), China's top economic planning agency. The price is well above the prices to be paid for the contracts signed by CNOOC with Australian and Indonesia suppliers for delivery to earlier terminals in Guangdong and Fujian (said to be capped at USD 3.10/MBtu and USD 3.80/MBtu, respectively). But the delivered USD 6 - 7/MBtu price is well below those discussed in other deals in the region (including buyers in Japan and Korea).

The Petronas deal is for 25 years, starting in 2009. Petronas said it would initially deliver 1.4 bcm per year (1 mtpa), rising to 4.5 bcm per year (3.3 mtpa) after 2012 from Malaysia LNG Tiga (III). Malaysia's three plants will have a combined production capacity of 32.7 bcm per year (24 mtpa) after the MLNG Dua (II) plant is debottlenecked by October 2009.

The additional supply may come from a third train at MLNG Tiga. It is not yet clear whether there are enough reserves to cover contract extensions at MLNG Satu and Dua as well as expansion capacity at Tiga, although a string of exploration successes in the waters off Sarawak may have eased these concerns recently. It is possible that Natuna D Alpha in Indonesia could feed the expansion. Meanwhile, CNOOC appears to have agreed with Indonesia's upstream regulator BP Migas to divert some of the Tangguh volumes contracted to supply to the Fujian terminal to Shanghai instead.

CNOOC says that it aims to build a trans-coastal natural gas pipeline linking major coastal cities from the south to the north in 10 to 15 years. The trunkline would be fed by imported LNG in addition to the company's offshore gas from Bohai Bay, East China Sea and South China Sea. The strategy is to build individual gas consumption centres first, to expand into surrounding areas and then to link each center with pipelines.

Expansion of the West-East pipeline

The entire 4 000-km West-East Pipeline, which supplies gas from the western Xinjiang region to the eastern consuming region including Shanghai, started commercial operation at the end of 2004. The pipeline carries 12 bcm per year, of which the Shanghai area consumes 1.3 bcm annualy. The pipeline operator, PetroChina, has a gas sale agreement with Shanghai Natural Gas Pipeline (which was signed in January 2004) under which the gas is sold at about USD 4.3/MBtu, delivered at the Shanghai city gate.

PetroChina plans to boost the capacity of the West-East pipeline to 17 bcm per year by the end of 2007 by adding compression to the existing facilities. The company also is considering construction of second, parallel pipeline that would carry gas from Xinjiang and, it is hoped, Central Asia and/or Russia (see separate sections). This parallel line would branch south at Zhengzhou in Henan Province and terminate in Guangdong Province. Assuming these projects go ahead, the ultimate total transportation capacity of the West-East pipeline system would be 26 bcm per year by 2020. Although details of the route have not been disclosed, there might be two new lines to be installed between Zhengzhou and Wuhan in the Hubei Province and between Changsha Hunan Province and Guangzhou in Guangdong Province, as a transmission pipeline is already in operation between Wuhan and Changsha.

Expansion of the Pinghu pipeline

The Pinghu gas field in the East China Sea southwest off Shanghai, operated by Shanghai Natural Gas Co., a joint venture between Shenergy (40%), CNOOC (30%) and Sinopec (30%), started to deliver gas to the Pudong district of Shanghai via a 389 km undersea pipeline in 1999. The delivered volume is to be boosted to 800 mcm per year by the end of 2007 from the current 600 mcm per year. The wholesale "city gate" price is reported to be around USD 5.1/MBtu in 2005.

Sinopec's Sichuan-East pipeline

Sinopec (China Petroleum & Chemical Corporation) plans to construct a pipeline to supply gas from the Puguang field in northeastern Sichuan Province to growing markets of the eastern seaboard, including Shanghai. The company claims that the Puguang field is one of five gas fields with reserves of more than 200 bcm discovered in China. In early 2006, Sinopec submitted a proposal for Phase I development to the National Development and Reform Commission (NDRC. A pipeline was originally planned from the field to Jinan in Shandong Province. The State then authorized the company to commence preliminary work on the project.

In summer 2006, Chairman Chen Tonghai of Sinopec stated that the proven reserves stood at 322 Bcm and anticipated production of commercial gas of more than 9 bcm per year by 2008 and 12 bcm per year by 2010.

Table 28 China's domestic pipeline plans

	Promoters	Anticipated yearly volume
West-East expansion	PetroChina	Current: 12 bcm By 2007: 17 bcm By 2020: 26 bcm
Pinghu expansion	Shanghai Natural Gas Co. Shenergy (40%), CNOOC (30%), Sinopec (30%)	Current: 0.6 bcm By 2007: 0.8 bcm
Sichuan-East	Sinopec	By 2008: 9 bcm By 2010: 12 bcm

Source: Media reports.

The company apparently planned the pipeline to Shandong for several reasons. The Sichuan gas market, the largest in China, is well developed and mostly controlled by the bigger rival PetroChina leaving little room for Sinopec. In turn, Sinopec has been developing the Shandong market and converting coal-based gas to natural gas in the region; Sinopec is thus trying to establish an advantageous position in Shandong against PetroChina. Moreover, Sinopec enjoys good relationship with the Shandong provincial government, as it operates the Shengli oilfield – China's second largest – and associated downstream facilities in the province.

In August 2006, the National Development and Reform Commission (NDRC), however, rejected the original plan and asked it to be revised to include gas supply to the Shanghai's Pudong district. Sinopec accepted the idea and submitted a revised plan. In the new plan, the main line would be a 1 674-km one from the field to Shanghai, with an 842-km branch from Yichang in Hubei Province to Henan Province.

In addition to the pipeline supply, the company is reported to have a plan to install a USD 520 million (4.3 billion yuan) gas-to-liquid (GTL) project in Chongqing City with initial production capacity of 2 million tonnes per year fed by the Puguang field.

India

India's production and consumption

Gas represents less than 10% of total primary energy demand in India. In fiscal year 2005/06[17] India used 38.4 bcm of gas, compared to demand of 34 bcm in 2004/05. Of the use in 2005/06, 31.3 bcm was sourced domestically and 7.1 bcm was imported as LNG. The public sector accounts for 78% of production, while private producers for 22% of production.

The medium- to long-term trend points towards a strong increase in private/JV gas, while the gas from public fields, based

17. India's fiscal year runs from 1 April to 31 March. Production for calendar year 2006 stood at 31.6 bcm.

on the Administered Pricing Mechanism (APM) declines. APM gas is currently sold at about USD 1.8/MBtu while private/JV gas is sold at around USD 4.5/MBtu. Indian domestic supply is not sufficient to meet current demand. Against official demand of 118 mcm per day, actual supplies were only 62 mcm per day during the last fiscal year. It is unclear how high suppressed (or latent) demand is.

The domestic production outlook is tentative despite the undisputed existence of large gas reserves. Estimates over India's future production vary. According to the government, India could produce 42 bcm in year 2010 (down from 44 bcm in the *GMR 2006*). By 2015 this could increase to 59 bcm with the majority of gas supplies from the private sector. The uncertainty over domestic gas production is due to investment and pricing uncertainties; at what pace producers are willing to bring fields into production for a given price.

Reserves additions

There have been several considerable reserve additions under the New Exploration Licensing Program (NELP). Moreover, substantial parts of India's territory remain unexplored leaving the promise of additional significant reserves. India finalized NELP VI during 2006 under which it offered 55 exploration blocks. Preparations for NELP VII are ongoing.

Since launching its NELP process in 1999, three major finds have been made, all in the eastern offshore Krishna-Godavari (KG) basin. There is now talk that the KG basin and an area slightly north could contain up to 50 Tcf and the area has been dubbed optimistically the "new North Sea". Production and development of fields in the KG basin is costly due to the depth of the reserves and the difficult terrain. This will impact on the price at which these new domestic gas finds can be marketed.

Private sector joint venture (JV) Reliance-Niko was the first to strike gas in late 2002 and its block has estimated reserves of 410 bcm (14.5 Tcf). Production is now expected to commence in mid-2008 at an initial rate of 40 mcm per day to be doubled to 80 mcm per day by end 2009. Based on current indications Reliance-Niko expects a minimum selling price of USD 4/MBtu. This price is widely believed to be too low to remunerate development costs and associated investments in pipelines.

Gujarat State Petroleum Corporation (GSPC) has estimated reserves of 566 bcm (20 Tcf) in an adjacent block to Reliance-Niko. Production from this field is expected for 2010/11 at a rate of 54 mcm per day. Finally in late 2006 ONGC announced that it had found around 595 bcm (21 Tcf) in a field in the same region. The upstream regulator has not yet certified the find. Based on available documentation the regulator will likely make a downward adjustment to a maximum of 396 bcm (14 Tcf) pending further tests by an independent third-party.

In addition several smaller gas finds have been made under the NELP. By 2010-11 it is expected that at around 100 mcm per day will be available from the private sector/JV from the KG basin alone. India is also looking towards exploiting its Coal Bed Methane (CBM) potential as an alternative source of gas. The third round of CBM-II policy was launched during 2006 and 10 CBM blocks have been awarded.

LNG imports

India's import capacity currently stands at 12.2 bcm per year (9 mtpa) through two terminals located on the Western coast. Petronet LNG's Dahej terminal is capable of handling 8.8 bcm per year (6.5 mtpa). Dahej is being supplied from Qatar under a long-term contract, supplemented by spot cargoes from other sources. The Shell-Total promoted Hazira terminal imported only 0.24 bcm (175 000 tons) through its 3.4 bcm per year (2.5 mtpa) facility during fiscal year 2005/06, the first year of operation. For the year ending in March 2007, the Hazira terminal operators expect a capacity utilisation of around 30%.

This increase in utilisation of existing infrastructure is primarily explained by Indian customers adjusting to paying international spot prices for gas. Fertiliser, power and petrochemical plants are the major customers and they are switching away from naphtha to gas. Mostly these industrial producers are not eligible for APM gas and are also experiencing problems obtaining supplies of domestically produced private/JV gas. However, some public sector power producers and steel companies have remained loyal to naphtha and show higher consumption during fiscal year 2006/07 then in the previous year. Whether this is due to lower naphtha prices as a result of a local supply glut, or to lack of availability of natural gas is difficult to determine.

After resisting for a long time, NTPC, India's largest public power sector producer, had to resort to buying spot LNG in 2006 for up to USD 12/MBtu to overcome supply constraints to its plants. This shift in customer attitude and the strong economic growth over the last years has resulted in a more positive assessment of the future of LNG in India.

By 2010 India's LNG import capacity could reach 31.3 bcm per year (23 mtpa). In addition to the Hazira plant, this would include; Dahej capacity expansion to 17 bcm per year (12.5 mtpa) by 2008; the commissioning of the Dabhol-Ratnagiri terminal at 7.5 bcm per year (5.5 mtpa) by 2009; and the initial 3.4 bcm per year (2.5 mtpa) phase of Kochi terminal which Petronet is promoting in the south western state of Kerala. Utilisation of the facilities is, however, subject to securing gas supplies and availability of pipeline facilities downstream.

India is working towards bringing the abandoned integrated Dhabol LNG regasification facility and power station into operation. The re-named Ratnagiri facility is currently operating its power plant at only 15% of the 2 184 MW capacity, using naphtha (as per the initial Dhabol contracts). The tentative date for commissioning of the Ratnagiri regasification facility is September 2009. Until the integrated regasification facility is ready, the Ratnagiri plant is expected to run on LNG supplied from the Dahej and Hazira terminals. Petronet LNG is charged with procuring 2 bcm per year and is hoping to source the LNG at a delivered price of USD 10 - 10.5/MBtu.

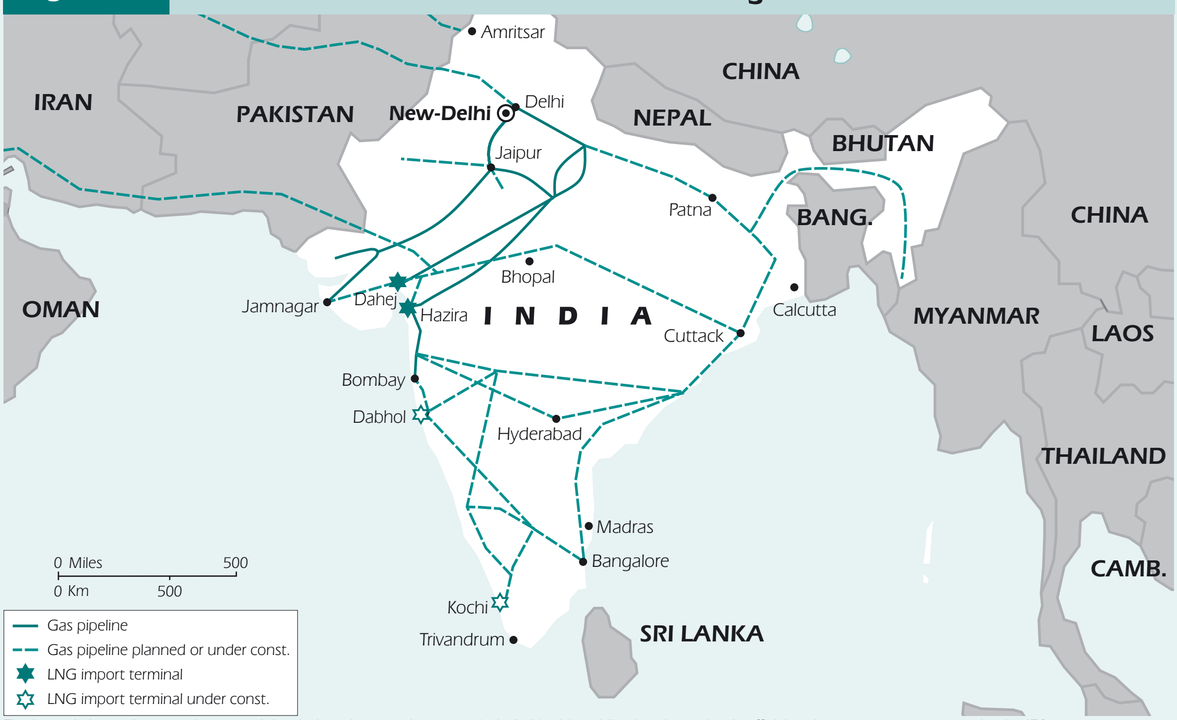
The construction contract for the Kochi terminal is to be awarded by end 2007, targeting a 2010 start-up. Petronet is negotiating with ExxonMobil for a 3.4 bcm per year (2.5 mtpa) share of the Gorgon LNG supply from Australia. Originally, it was planned that LNG to Kochi would be sourced from Qatar under a long-term supply contract commencing in 2009. However, Petronet is now considering diverting this gas to its expanded facility in Dahej. The Kochi terminal may eventually be expanded to 6.8 bcm per year (5 mtpa).

If all LNG terminals are made operational as currently planned and if domestic production from new fields comes on-stream as scheduled, India could be supplied with 87 bcm gas by 2015, of which 30 bcm would be imported as LNG.

Transmission system

India's transmission system will need to be substantially expanded to create an Indian gas grid. GAIL, the monopoly pipeline operator, operates about 5 600 km of pipelines with a capacity of around 130 mcm per day, of which only around 64% is currently used. GAIL has ambitious plans to further expand the system. Its two major priorities are to connect all LNG terminals with its trunk-pipeline in the West-North and to connect domestic gas on the Eastern coast to consumers in the North and South of the country. Private investment in transmission infrastructure has so far not been permitted. However, as part of the new sector regulatory framework, transmission now falls under the regulatory authority. Reliance is keen to engage in laying pipelines

Figure 45 **Gas infrastructure of India and surrounding countries**



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Source: The Petroleum Economist Ltd..

to be able to market its gas from the KG basin and has prepared the necessary project proposal for approval.

Pipeline imports

India's plans to import gas via pipeline from its neighbouring countries have not progressed physically during the last year. However, contractual progress came in the form of an agreement reached between India, Pakistan and Iran on the pricing formula for gas through the Iran-Pakistan-India (IPI) pipeline. Iran offered to sell gas at a price based on 6.3% of the Japanese crude cocktail (JCC, an average of Japanese crude import prices) in USD per barrel plus USD 1.15/MBtu with a ceiling of USD 70/bbl and a floor price of USD 30/bbl. Both India and Pakistan seem to have accepted this new pricing proposal.

India would receive a maximum of 90 mcm per day through the IPI pipeline. India's import price at the Pakistan border would be about USD 5/MBtu (at USD 60/bbl JCC) – without transit and transport charges. Clearly, the higher prices being paid for LNG imports and the potential pipeline imports will result in private domestic producers requesting higher gas sales prices within India.

Regulatory framework

The Petroleum and Natural Gas Regulatory Act, 2006 has been notified in April 2006 and the Regulatory Board is in the process of being established. The Board will be charged with regulating specific activities relating to petroleum, petroleum products and natural gas. However, upstream activities and pricing are excluded from the regulatory mandate. The Act provides for open access for transportation of petroleum products and natural gas on a common carrier principal.

India's "Policy for Development of Natural Gas Pipelines and City or Local Natural Gas Distribution Networks" was codified in December 2006. The policy seeks to promote competition and transparency in the transmission sector and is also charged with vertically unbundling interests in upstream and downstream sector where, for example, companies such as GAIL are present. The policy requires mandatory excess capacity of 33% for all pipelines which is likely to adversely affect the rate of investment in such pipelines.

Latin America highlights

Since the 1990s, the relationship between gas-rich countries and gas-dependent consumers has played a pivotal role in defining Latin America's energy landscape. Because of the capital costs required for its transport, the evolution of natural gas trade has been particularly revealing of the diverging rationale between energy politics and energy economics in the region. The recent rise in natural gas prices, stalled regional integration and declining or delayed upstream investment as a result of nationalization moves have further exacerbated that relationship.

In 2005, natural gas represented 20.5% of total primary energy supply in Central and South America. The region produced 135 bcm of gas and consumed 120.5 bcm, of which of which 32.5 bcm was used to produce electricity. Gas consumption in

South America – *i.e.* excluding Trinidad and Tobago – is highly concentrated. Five countries: Argentina, Bolivia, Brazil, Colombia and Venezuela, account for 95% of gas production, while Argentina, Brazil, Chile, Colombia and Venezuela represent 94% of primary gas consumption and 94% of gas used for power generation.

Gas dynamics in South America are exhibiting a growing paradox. Although the region has more-than adequate gas reserves to further develop the gas markets in general, and the gas for power segment in particular, because of the recent surge in resource nationalism in the main gas-supplying countries and the ensuing concerns over energy security, gas consuming countries are increasingly turning to liquefied natural gas (LNG) as a more reliable source of supply. Many of South America's natural gas resources are located in countries that are increasingly antagonistic toward foreign and private investment and are considered as unreliable partners in cross-border gas supply agreements, most notably Argentina, Bolivia and Venezuela.

Therefore, while there is a compelling economic rationale for intensifying regional energy trade and regional energy integration, current political and economic trends are leading South American policy makers to focus on their national interests and on energy security. This dichotomy is remarkably illustrated by the long standing dispute between Bolivia and Chile, when both countries' economies could significantly benefit from cross-border gas trade. In this context, LNG represents a more stable source of supply with more transparent price and contracting terms and available within a shorter timeframe than most natural gas pipeline projects. Despite the higher cost involved in developing LNG capabilities, diversifying supply options and linking national markets to the rest of the world is seen as more flexible and more secure than expanding or building new pipelines that tie some countries to their neighbours. In several cases, previous plans to expand and extend pipeline networks to link producing countries with major consumption centres have given way to new calls for LNG terminals. Accordingly, in the last three years, four regasification terminal projects for natural gas in South America have been announced, two in Brazil and two in Chile.

The Southern Cone conspicuously illustrates the trend away from regional co-operation. The uneven geographical distribution of gas reserves and gas demand centres had led (in the 1990s) to a rise in cross-border gas trade, with Argentina and Bolivia as the main gas suppliers and Chile and Brazil as the largest gas importers. Yet today, while on a physical/technical level the availability of gas supplies remains unquestioned – Bolivia is endowed with the second largest natural gas reserves in South America – on a political level, the security of cross-border gas supplies has become a growing concern. Argentina's unilateral cuts of its exports to Chile and the uncertainty linked to Bolivia's future gas exports following the May 2006 nationalization of the sector have underlined these concerns.

Insufficient gas supply has plagued Argentina since 2004 after years of sub-sidized gas prices and underinvestment. To avoid cuts to its domestic consumers, Argentina unilaterally decided in mid-2004 to cut exports to Chile, creating severe supply problems for the latter. Chile, which has very limited gas reserves, has seen its daily gas supply from Argentina occasionally reduced by up to 50% in the past two years.

Chile is therefore turning to LNG to compensate for rapidly declining Argentinean pipeline gas, on which it depends for about 75% of its current 22 mcm per day gas consumption. The Mejillones project is slated to start up operations by end 2008 with initial shipments of 5-6 mcm per day. This comes in addition to the Quintero LNG terminal already under way, which is expected to start operations in late 2008, with a capacity of 3.4 bcm per year (2.5 mtpa). By 2010 Chile plans to receive less than 50% of its gas supply from regional sources, down from 75% in 2005.

Peru could potentially export LNG to Chile in the medium term. In early 2007, Peru LNG consortium, lead by Hunt Oil, moved to construct an LNG pipeline and export terminal at Pampa Melchorita, 135 km south of Lima. The Peru LNG facility will have an operating capacity of 6 bcm per year (4.4 mtpa), with most of the production destined for the West Coast of North America. Peru LNG consortium has also held discussions with ENAP, Chile's state-owned oil company, about the possibility of exporting LNG to Chile.

Given the obvious complementarities among Southern Cone countries, an ambitious pipeline project that would bring gas from Peru's giant Camisea field to northern Chile and from there, connect into the Argentine and Southern Cone gas network was proposed in mid-2005. The proposed project would involve the construction of a 1 500 km pipeline along the Pacific coast from Peru to Chile, as well as the use of existing pipelines from Chile to Argentina and the construction, expansion, or completion of pipelines in Argentina, Brazil and Paraguay. The whole project has been estimated to cost between USD 2.5 and USD 3 billion. After several high-level multilateral meetings, discussions about the project have subsided somewhat since December 2005, following diplomatic friction between Chile and Peru and the announcement of a competing regional pipeline project from Venezuela. The current regional political climate is not particularly favorable for such a project to move forward.

Bolivia has seen gas production capacity reach a plateau despite large proven and probable reserves. The nation lacks the necessary capital and foreign investors have put a hold on any new investments. This lack of investment in exploration and production and in transportation has delayed the sanction of any new export projects in the short to medium term. Net foreign direct investment (FDI) in Bolivia averaged 10% of GDP between 1998 and 2002, collapsed to 2.4% of GDP in 2003 and 1.3% of GDP in 2004. According to the United Nations' Economic Commission for Latin America and the Caribbean (ECLAC), FDI turned into a net export of USD 279.6 million, or -3.3% of GDP in 2005.

On October 31, 2006, the Bolivian government concluded the renegotiation of upstream operations contracts with all twelve E&P operators active in the country (BG, Total, Repsol YPF and Petrobras, among others). However, this achievement was subsequently undermined by the various postponements of the signing of those contracts. Further delays in approving these new gas contracts signed by Bolivia and Argentina could threaten YPFB's (State oil and gas company of Bolivia) investment programme resulting in possible shortages of gas destined for Argentina. Some 44 contracts are still to be approved by the Bolivian Senate; they include the construction of a new gas pipeline from Bolivia to Argentina, and the gradual increase in gas exports from 7.7 mcm per day, to up to 16 mcm per day in 2009 and then 27.7 mcm per day in 2010 until 2025 and would cost an estimated UDS 1.6 billion.

Brazil is by far the country most affected by the Bolivian hydrocarbon nationalisation as it depends on Bolivian gas for roughly 40% of its total gas supply. State-controlled Petrobras is the company most affected by the new measures introduced by Bolivia's nationalisation process. Gas currently accounts for 9.1% of Brazil's primary energy supply, as the result of an explicit government policy aiming to diversify energy sources in all sectors, including for thermal generation. The two countries are linked by the 3 150 km Gasbol pipeline, the single largest private-sector investment in South America to date with a total cost of USD 2.1 billion. The pipeline has a maximum 29.7 mcm per day capacity and started operating in 1999. Brazil currently imports an average 26-28 mcm per day from Bolivia through the Gasbol pipeline. A concern in the wake of the Bolivian nationalisation in the medium-term is therefore the possible reduction of gas imports, at a time when Brazil is short of alternatives and already faces gas supply restrictions in the Northeast.

By 2010, Brazil hopes to reduce regional gas imports to one third or one quarter from roughly 50% in 2005, thanks to a combination of a substantial increase in domestic production and LNG imports. Combined investment in the LNG and regasification program is estimated to cost USD 2.36 billion, including lease and operating costs of two floating storage and regasification units (FSRUs). The first planned FSRU would process 14 mcm per day and would be anchored in the bay located off the southeastern coast of Rio de Janeiro, close to the country's largest natural gas market. The other FSRU would be located on the coast of Ceará State in northeastern Brazil where there is large demand from thermal plants and would have a capacity of 6 mcm per day. By 2010-2011, Brazil therefore plans to import 7 bcm per year of natural gas through these two regasification terminals. The country has yet to tender contracts for the LNG regasification terminals as well as for gas supplies. Thermal generation is supplementary to hydro generation in Brazil. This fact leads to low load factors in thermal generation plants. Therefore, LNG imports make sense as they avoid additional investments in pipeline capacities, especially since the artificially low prices of gas for thermal-electrical generation have started to significantly increase in 2007.

In **Venezuela**, President Chávez announced after his reelection in December 2006 that he would modify the gas law in line with the oil re-nationalization process. This is likely to have a more limited impact than for the oil sector given that the private sector currently holds less than 10% of the country's current gas output.

Venezuela claims to have 4 300 bcm of of proven reserves of natural gas, yet insufficient gas supply in the west of the country has affected petrochemical and electricity production. This is the rationale for a 230 km underwater pipeline to import gas from neighbouring Colombia whose construction began in July 2006, with a total budget of USD 280 million. The energy ministers of both countries recently declared that the transoceanic pipeline would be finished by the end of August 2007.

The relationship between gas and power generation

In Central and South America, natural gas is the fastest growing fuel source, with demand growing on average around 5% per year between 2000 and 2005. In the coming years natural gas is likely to overtake oil as the second most prevalent fuel for electricity generation in the region, while hydropower would remain the dominant source. The main structural limitation to gas-based power generation in South America is the abundance of hydropower. This is especially true for Brazil and Colombia, where the share of hydropower represented over 80% of gross electricity production in 2004.

Growing power demand across the region, driven by relatively high economic growth rates as well as by improving electrification rates indicates that additional power generation capacity will be needed. However, the pace of gas for power demand growth could vary,

Figure 46 **Major South American natural gas flows, 1975-2005**

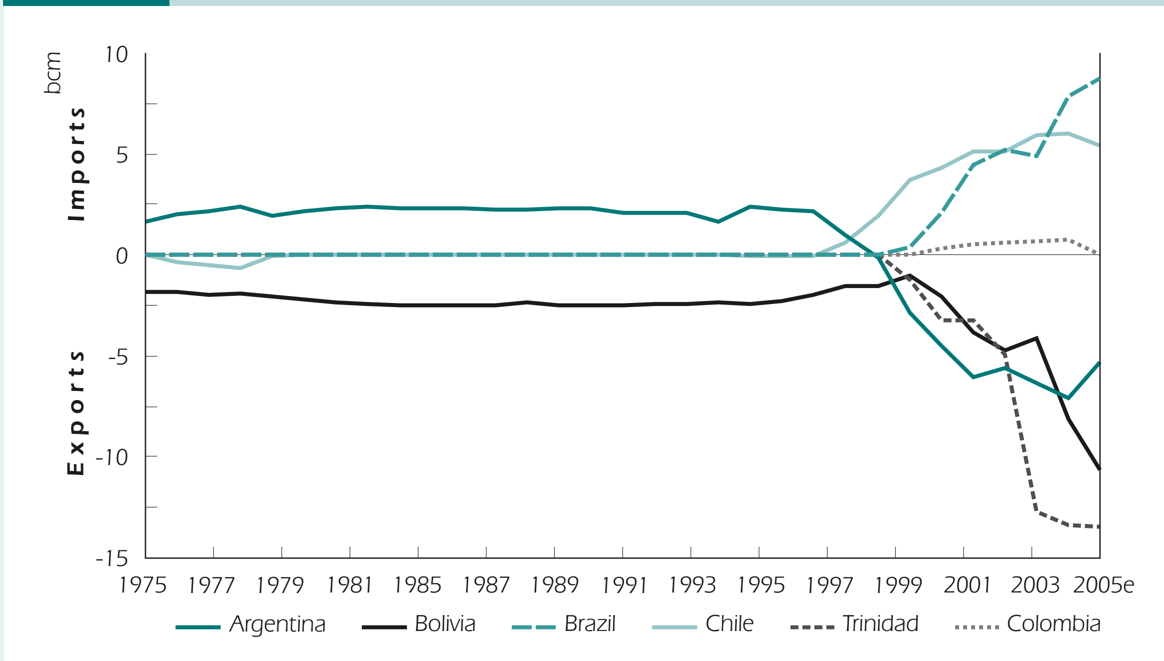

Figure 47 Gas infrastructure of South America and surrounding countries

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Source: The Petroleum Economist Ltd..

reflecting higher prices which are also affecting the competitiveness of gas-powered electricity. Because until recently South America's gas markets were isolated from the rest of the world, gas prices were sheltered from price fluctuations in other markets. Recent LNG developments have linked the region to the rest of the world and producers such as Bolivia are accordingly raising prices to extract a greater share of the natural gas production rents. Consequently, the cost of incremental natural gas production, combined with the political risk price premium, is forcing many importer countries to take alternatives into consideration, especially coal-fired power plants and greater use of domestic renewable resources such as hydro and wind.

Therefore, on the one hand LNG could delay investment in E&P in some countries by opening new sources of supply to a formerly captive market. On the other hand, the influx of LNG will likely impact regional prices by creating a common international reference parameter and could therefore provide incentives to invest in E&P in other countries to generate higher revenues.

Concluding remarks

The Bolivian nationalization and the re-nationalization drive in Venezuela have triggered a reversal of the gas integration trend of the 1990s. Concerns about the reliability of bilateral gas supply agreements and increasing gas prices in the region are significantly refocusing national energy policies away from cross-border trade and joint pipeline projects toward global integration and the autonomous development of LNG. Regional energy integration has turned into a geopolitical project, disconnected from economic rationality and likely to remain at the level of grand political rhetoric.

In this context, the Great Pipeline of the South has become the flagship project for Venezuela's Latin America energy integration plans. The mega pipeline would cost an estimated USD 20 billion to link southern Venezuela to Argentina and continues to be promoted by the Venezuelan government despite its questionable economic rationale and highly challenging execution. To date, the other regional giant, Brazil, has opted for a conciliatory approach without signing into any financial or binding commitments.

OECD COUNTRY/REGION UPDATE

North America

Together, the Canadian and United States natural gas markets form the largest integrated gas market in the world, with Canada providing about a quarter of the combined gas production. In 2006, United States consumption was 618 bcm, met from domestic sources (525 bcm) with almost all the balance coming from Canada. As the world's second largest natural gas exporter, Canada exports over half of its production to the United States, (104 bcm out of 190 bcm in 2006) accounting for about 15 % of United States' gas consumption.

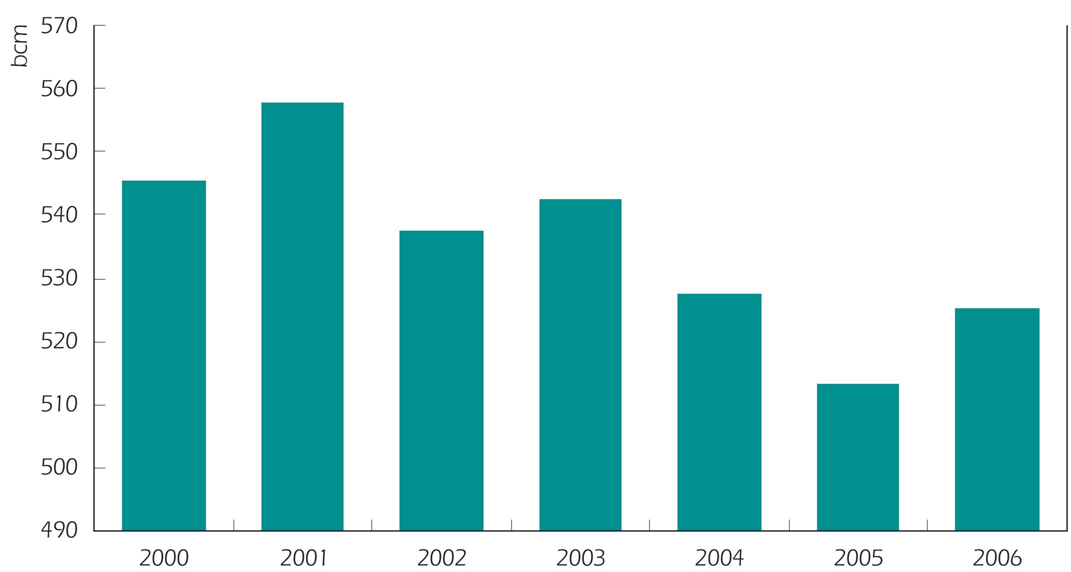
After a record 2005 hurricane season on the United States' Gulf Coast, two relatively mild winters left storage at high levels. The gas storage surplus that started in the winter of 2005-2006 grew to a record 18% surplus at the beginning of 2007. However a large amount of natural gas was withdrawn from storage in February following a particularly cold period.

Of special significance in the United States was that the summer of 2006, during a period of exceptionally hot weather, saw two consecutive weeks of natural gas storage withdrawals in late July and early August, the first-ever draws on inventory during the summer, threatening current patterns of seasonality. For the year 2006, gas use in power was up 6.5 %.

Despite records for gas drilling production remains essentially flat

For 2006, the average natural gas rig count in the United States continued the increases seen in the last four years, growing 16% to 1 372. Gas producers suffered in the fourth quarter of 2006 due

Figure 48 United States' gas production: has it peaked?

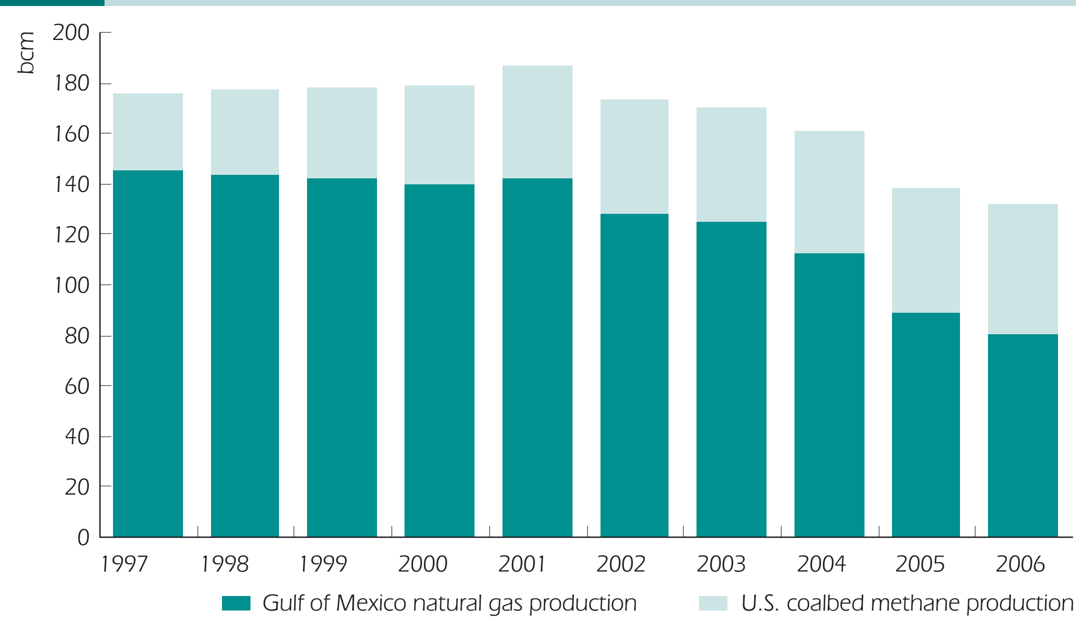


Source: IEA.

to a 44% slump in gas prices to an average of USD 7.25/MBtu, while service costs for drilling continued to escalate. Competition for rigs has driven costs higher. Net income of the independent United States' oil and gas producers declined 62% between the fourth quarter 2005 and fourth quarter 2006. This group of producers develops 90% of the United States' domestic oil and gas wells, produces 68% of domestic oil and 82% of domestic natural gas.

The same escalating costs and lower gas prices have impacted Canadian companies harder. Canada has a high proportion of shallow gas wells that deplete quickly and are less profitable to drill when prices are low. The strength of the Canadian dollar in recent years has meant producers have been realizing lower returns for their output than their United States' counterparts. Costs in Canada are climbing at an average annual rate of about 10%. The Canadian dollar has appreciated 38% since 2002, further eroding returns to producers. 370 Canadian rigs were operating in January 2007, 200 less than the record of 580 set in 2006. Prices in Alberta fell by almost two-thirds over the course of 2006. February 2007 saw some recovery, but prices were still 22% below those of early 2006. Companies responded to all these factors by reducing capital budgets 25 - 70% in the last half of 2006 as costs continued to climb. Major producers, including the country's top three: EnCana Corp., Canadian Natural Resources Ltd. and Talisman Energy Inc., all of Calgary, significantly reduced their gas exploration budgets for 2007. Some USD 7 billion in capital was pulled out of the USD 33 billion conventional industry in Western Canada. The Conference Board of Canada forecasts only a marginal increase in production – about 0.2% – for 2007.

Figure 49 **United States' coalbed methane and Gulf of Mexico gas production**



Source: EIA DOE (2006 CBM Production Provisional).

United States' production is likely to struggle as the anticipated growth in unconventional production (coal bed methane, shale and tight sands gas) does not offset clear declines in conventional gas output. When adjusted for the impact of the hurricanes, United States' production grew only modestly in 2006 despite the robust drilling and remains below the peak seen in 2001. In the short-term, continued expansion of unconventional production may be sufficient to hold United States' production at constant levels or even expand production modestly for several more years, as predicted by the United States' Energy Information Administration (EIA). Figure 49 shows two of the most dynamic sectors in United States production; coal bed methane (growing) and Gulf of Mexico (declining).

At the beginning of 2006, the major Canadian production area, the Western Canadian Sedimentary Basin (WCSB) had remaining gas reserves of about 1 613 bcm and a reserves-to-production ratio of approximately nine years. Since 2001, production from the maturing WCSB has flattened out, despite relatively high drilling activity; production in 2006 was about the same as 2005. Marketable gas production is expected to decline by about 10 % over the period to 2015. Production of coal bed methane (CBM) is in its infancy. However, as conventional resources deplete, CBM will play an increasingly important role due to the large resource potential. Projected increases in CBM production over time may offset declines in conventional gas production. Inflationary pressures in the drilling sector have particularly affected higher-cost CBM wells.

In summary, the cost of getting gas to the end user has risen due to a combination of factors ranging from a tight service market in terms of both rigs and skilled labour. Because of these inflationary pressures, high gas storage levels at the end of the winter heating season have been less of a factor in determining the direction or level of gas prices.

Despite uncertainties about gas supply, gas demand is expected to grow, led by power generation

In the United States, total natural gas consumption is projected to increase by 2.9% in 2007 and 1.8% in 2008, after falling by 1.7% in 2006, on the back of lower residential and commercial demand (residential demand in January and December 2006 was 20% less than corresponding months a year earlier).

The Annual Energy Outlook 2007 (AEO 2007) reference case, released in February 2007 by the EIA, reflects the evolution of energy markets in an era of high prices by projecting growth in nuclear generation, more biofuels (both ethanol and biodiesel) consumption, growth in coal-to-liquids (CTL) capacity and production, growing demand for unconventional transportation technologies and accelerated improvements in energy efficiency throughout the economy.

In these forecasts, the amount of natural gas needed to meet the United States demand grows some 16% over the decade to 2015. Most noteworthy is the rapid growth in the amount of natural gas required to generate electricity, which has increased 54% in the last decade, including more than 32 bcm in the past three years. Gas use for power is forecast to grow by around 23% to 2015, although the average of private forecasts quoted in the Outlook shows a 40% increase (this latter figure would imply gas demand increasing by around 80 to 90 bcm at current efficiencies). After 2015-2020, growth is expected to slow, when new coal and nuclear units appear. Enough gas-fired capacity is in place today for electric generation to increase sharply. Existing gas capacity had a 35% utilisation rate in 2006 compared to 71% for coal. However, higher prices may encourage conversion of the lower efficiency boilers and turbines to higher efficiency combined cycle plant, reducing the gas supply needed to increase generation output.

Behind these power demand forecasts, several other trends can be discerned. Firstly, price sensitive industrial users have been reducing demand. Industrial demand has fallen by nearly a quarter over the last decade, with sharp drops noticeable in 2001, when prices rose almost 20% and 2005, where hurricane induced price rises of 30% were especially damaging to industrial demand (as discussed in the Natural Gas Market Review 2006). Secondly, a first quarter comparison of EIA's estimated residential consumption shows a 14% increase from 2006 to 2007, reflecting a return to more normal cold weather compared to 2006. Taking the year as a whole, residential consumption is expected to increase 10.8% in 2007. But the American Gas Association (AGA) points out that on a weather normalized basis, residential gas use declined 13% from 2000 to 2006, as residential consumers react to higher prices. AGA believes that at least half and as much as two-thirds of the 13% is permanent loss. Against these trends there are signs of increasing gas demand in the refining sector and also associated with ethanol production.

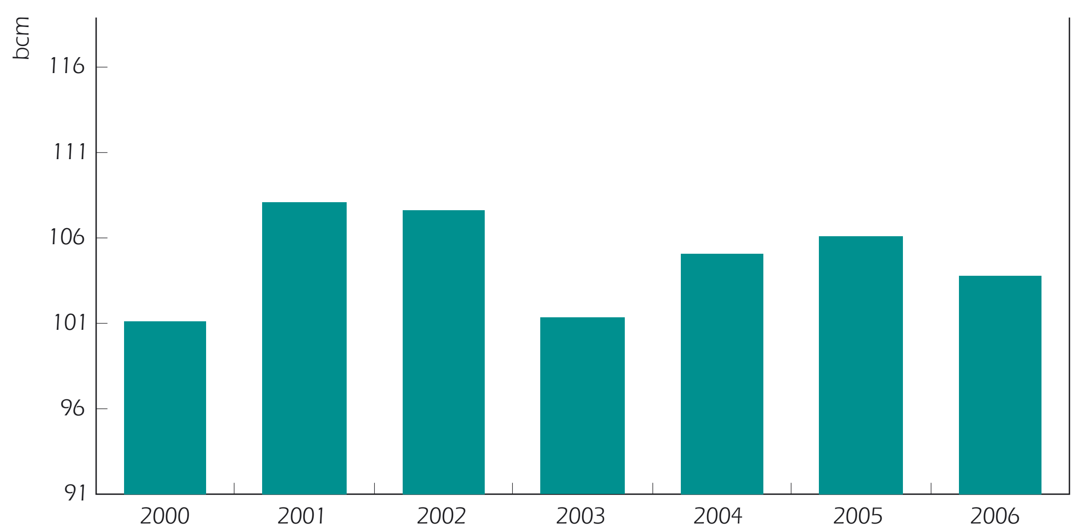
Growing demand in Canada will affect exports to the United States. With a well developed gas pipeline network linking producing areas to markets, natural gas is widely available from coast to coast in Canada. Total Canadian gas consumption increased by 2.3 % in 2006 to just over 100 bcm. With approximately 50 % of Canadians heating their homes with natural gas, residential gas demand experiences significant seasonal fluctuations and can be volatile in winter depending on weather conditions. Commercial and industrial gas demand is generally responsive to macroeconomic activity and gas prices.

The power generation and oil-sands sectors provide large potential for demand growth in the medium and long term. The last decade has seen noticeable additions in gas-fired capacity in several provinces, with most increases concentrated in Ontario and Alberta. In Ontario, the government decision to phase out approximately 6 000 MW of coal-fired capacity by 2014 has provided opportunities for new gas-fired power plants. Although there are several large hydro projects under development in hydro rich provinces of Quebec, Manitoba and Newfoundland and Labrador, as well as significant development expected for other renewable power, gas-fired generation is expected to remain an important technology for new capacity additions during the coming decade. This will add to the incremental demand for gas in this sector, from the current level of around 9 bcm annually. Official forecasts show the gas share of electricity rising from 5% in 2004 to 14% in 2010 and 23% in 2020. The latter figure implies around 180Twh of gas fired power output, around 40 bcm at current efficiencies. In June 2006, the Ontario Energy Minister directed the Ontario Power Authority to prepare a 20 year electricity supply mix plan. The Government has accepted OPA advice that natural gas should only be used to meet peak demand and ensure local reliability. Ontario's future electricity demand is likely to feature higher shares of renewable energy demand, plus greater end use efficiency.

The Canadian oil sands industry concentrated in the Fort McMurray area in Alberta represents another large domestic market for natural gas. Currently, the amount of natural gas used in the oil sands operations amounts to approximately 10 bcm. With anticipated rising oil sands production, gas demand from the oil sands sector is expected to double current consumption by 2015 and to continue rising after that date.

With rapid growth expected for the oil sands, coupled with further gas-fired power additions, natural gas demand is expected to rise further to 2015. Canadian exports to the United States fell a little over 2% in 2006. By 2015, total Canadian gas demand could be 25 to 30% higher than current consumption levels. With increasing domestic demand and flattening domestic production, gas exports to the United States will probably trend downward over the coming decade, resulting in a decline by about 5% over the period to 2015.

Figure 50 Canadian gas exports



Source:IEA.

North America is setting itself to import LNG in large quantities

Although LNG imports declined in 2006, most forecasters are predicting a rapid increase in LNG imports.

In 2007, pipeline imports from Canada are expected to fall by about 5 bcm , with a similar rise in LNG imports to around 22 bcm, rising to 30 bcm in 2008. These increases will be supplied from the significant expansion in world LNG supplies from Nigeria, Trinidad and Tobago, Equatorial Guinea and from the Snøhvit project in Norway (Further details are provided in the LNG section). Global LNG supplies are expected to be tight due to supply restraints, project delays and rapid growth in global demand. Nonetheless, importers remain confident that North America will attract these volumes of LNG supplies, because:

- Regasification capacity will be more than adequate as 12 terminals with 150 bcm of capacity will be in place by 2012.
- Strong development of infrastructure to move gas from LNG terminals to markets has taken place (see below).
- North America has strong infrastructure to handle seasonal demand swings (unlike some competing markets in Europe).
- Hence, the liquid North American market will be able to absorb large volumes at almost any time of the year.
- The marginal cost of production is high in the United States and this is the major factor setting Henry Hub prices and in turn the attractiveness of LNG sales to North America, since the latter will be priced on a Henry Hub basis, possibly with a slight discount.

While North American market structures make it difficult to contract long-term for dedicated production capacity, increasing volumes of LNG are being produced outside the framework of long-term contracts and these are being targeted primarily at North American markets. Several new liquefaction projects are having price clauses written on a Henry Hub basis, as discussed in the LNG section.

Infrastructure development is strong...

In the United States, functioning markets and generally sound regulation are underpinning infrastructure projects such as pipelines and storage in the lower 48 states.

According to current Federal Energy Regulatory Commission (FERC) applications, gas pipeline projects to be started or completed in 2007 will extend over 2 000 miles and capitalize on the increased unconventional production in the Rocky Mountains. Large west to east natural gas pipelines continue to be planned, the largest (in 20 years) being the 1 323 mile Rockies Express from Wyoming and Colorado to Ohio. The 20 bcm per year, USD 3 billion pipeline is expected to be completed in 2009. The driver for this pipeline has been the large persistent price differential between Rocky Mountain and Mid West prices.

The Kinder Morgan Midcontinent Express Pipeline will carry 15 bcm per year 800 km from Oklahoma to Louisiana to interconnect to northeastern markets. Although it has not been approved yet, startup is predicted for early 2009.

Expected growth in LNG imports will be backed by an improved network to move regasified gas from terminals to market:

- Energia Costa Azul Sempra LNG 72 km, spur line due end 2007.
- Elba Express (El Paso Corp.) in 2010, USD 850 million, 307 km 12 bcm per year.
- Kinder Morgan Louisiana Pipeline, 35 bcm per year of capacity from Cheniere's Sabine Pass LNG terminal USD 500 million.
- Brunswick Pipeline (9 bcm per year) from Canaport LNG terminal near St John in Canada, to connect with Maritimes and Northeast Pipeline system in Maine late 2008.
- Cameron Interstate Pipeline from Cameron LNG terminal to 7 inter- and intra-state pipelines to Midwest and Northeast (2008).
- Jordan Cove, 400 km, Jordan Cove LNG receiving terminal to Pacific Northwest system (currently in FERC pre-filing).

At the beginning of 2007, there were 44 storage facilities operating in the Gulf production area. According to FERC, 13 storage projects (which will expand the working gas capacity by a quarter) have been proposed or are under development in the Gulf region. Six existing facilities are expanding current working gas capacity and deliverability.

In Canada, development of upstream gas storage capacity has also been pursued, mainly in Alberta. TransCanada, a key player in the North American gas business in its capacity as the principal natural gas shipper in Canada, currently owns 3.9 bcm of storage capacity, composed of 1.4 bcm at Edson (Alberta), completed in 2006, 1.4 bcm at CrossAlta (Alberta) and approximately 1 bcm with third parties. The CrossAlta storage facility completed a major expansion in the autumn of 2005. The additional gas storage capacity will help balance seasonal and short term supply and demand and provide flexibility to the supply of natural gas.

... but some big pipelines are slow to develop

In addition to increased LNG imports and a rapid growth in unconventional production, the completion of an Alaskan natural gas pipeline now projected to be in service by 2018 will be an important component in meeting future North American gas demand. Alaskan production could provide as much as 60 bcm per year.

Former Alaskan Governor Frank Murkowski in 2006 presented a 460-page draft contract with Exxon Mobil, Conoco Phillips and BP to the state legislature setting tax and other terms for a pipeline project they might build. That proposal failed after most state lawmakers criticized it as providing too little revenue to the State.

His successor, Governor Sarah Palin, has submitted natural gas pipeline legislation (Alaska Gasline Inducement Act) designed to address these concerns. If the legislature approves the bill, it would provide cash and other incentives to potential builders of a pipeline that would carry the North Slope's vast reserves of natural gas to North American markets. Palin's bill takes into account many of the criticisms that arose during the debate on Murkowski's proposal. Nonetheless, it seems unlikely the legislation will be passed in 2007 – further delaying this project.

A second large project is the Canadian Mackenzie Gas Project (MGP). To meet the projected increases in North American gas demand, a consortium of large companies led by Imperial Oil proposed the MGP and filed applications for regulatory approvals in October 2004. The MGP is a 1 200 km natural gas pipeline with an initial design capacity of 12 bcm per year, proposed to be constructed from the Northwest Territories to the northern border of Alberta, where it would connect to the Alberta System. Throughout 2006, the MGP proponents participated in public hearings convened by the National Energy Board (NEB) and by a Joint Review Panel (JRP) constituted to assess socio-economic and environmental aspects of the project. These latter hearings are expected to conclude in the second quarter 2007, with the JRP's report ultimately being submitted into the NEB review process.

In March 2007, Imperial Oil filed its updated cost and scheduled information to regulatory entities. Their submission shows a more than doubling in the total project cost to USD 13.9 billion including: USD 3.0 billion for the gas gathering system, USD 6.7 billion for the Mackenzie Valley pipeline and USD 4.2 billion for the development of the anchor fields. The regulatory filings also indicate that the start up date will be no "sooner than 2014", about two years later than initially anticipated. Proponents of the project are Imperial, ConocoPhillips Canada, Shell Canada, Exxon Mobil Canada and the Aboriginal Group; the later formed in 2000 to enable ownership interest by the aboriginal peoples of the Northwest Territories in the proposed pipeline.

Mexico struggles to meet demand

Facing stagnant gas production and a sharp decline in its largest oil field, Mexico's new President Calderon is struggling to find a way to open his country's closed energy market to foreign investment.

Mexico is a major gas user (50 bcm in 2005). Like the United States, Mexican gas demand growth is driven by electricity generation, which accounts for around 44% of gas use and now provides 36% of power needs. Electricity demand growth is expected to remain strong. Since 1998 domestic gas production has been flat. Accordingly, Mexico's demand for natural gas has outpaced the country's production over the last decade and imports have tripled between 2000 and 2005 to10 bcm.

The state petroleum company PEMEX is constrained by a shortage of investment funds, as well as institutional and ideological concerns, that have led to laws and regulations that have blocked private capital and participation. Lacking capital and technology, PEMEX has been unable to expand reserves or exploit development opportunities. The solutions appear to be increased imports from the United States and LNG.

Newly elected President Calderon has introduced partnerships that permit foreign investment but do not offer foreign companies the right to own oil or gas resources. Pemex recently offered these multiple service contracts (MSC), whereby the company can hire a private contractor to conduct production activities in proven reserve areas, against cash payments. The success of the first MSC bidding rounds has been mixed, while the constitutionality of this type of contracts has repeatedly come under attack. Yet they are one of the very few instruments that would allow the Mexican government to increase private sector participation.

Opponents portray Calderon's energy reform proposals as an excuse to privatize the energy sector, a strategy that plays on Mexicans' fear of being sold out to foreign interests. The former energy minister will have a tough time convincing an opposition-dominated Congress to enact his much needed reforms.

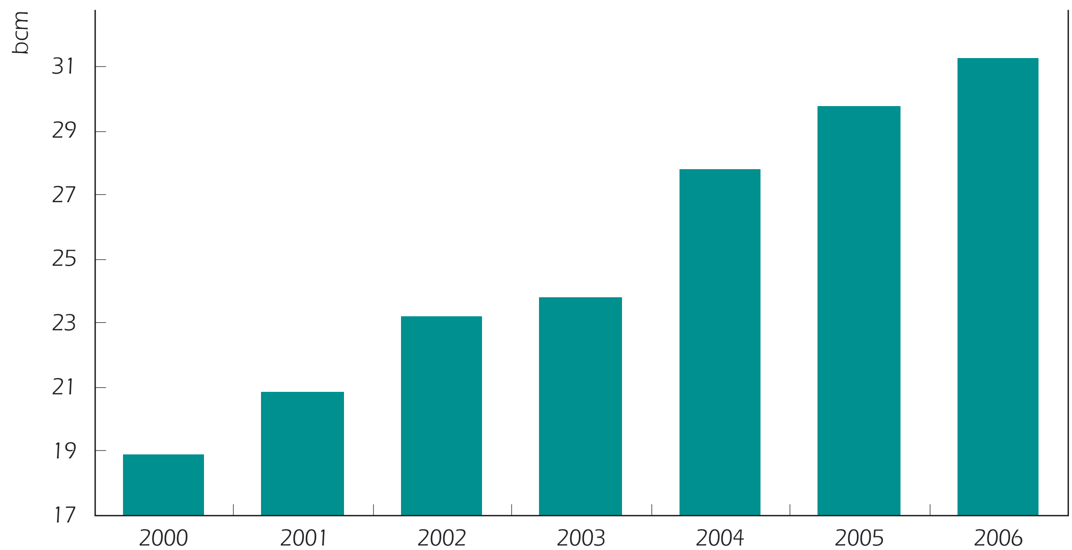
In August 2006, the Altamira terminal on the country's east coast (owned by Shell, Total of France and Mitsui of Japan) accepted its first delivery. The Costa Azul terminal on Mexico's west coast is under construction, with a likely 2008 completion, intended to supply some gas to Southern California, as well as meet local needs. Gas supplies are likely to come from Indonesia and Russia. Chevron announced that it has given up a project to build an additional LNG facility on the western coast of Mexico. The project would have involved an investment of USD 650 million. Chevron had earlier decided to send natural gas from its Greater Gorgon natural gas fields off northwest Australia to Japan.

Republic of Korea

Korea relies almost totally on LNG imports for gas supplies. It consumed about 31 bcm of gas in 2005, up 8% from 2004. LNG imports rose 10% in 2006. As can be seen from Figure 51, gas consumption has grown rapidly in recent years. The first LNG shipments arrived in 1986 and gas use reached 5.6% of TPES by 1995, rising to 12.5% of TPES in 2005. The largest use of gas in Korea is for power generation (42% in 2004) where it has now overtaken the use of oil. The government has recently stated its intent to increase the use of nuclear generation in the power sector, which could, in future, lead to a decline in gas consumption.

The average annual growth of gas use in the domestic sector was 30% in the period 1990 to 2000 and gas has now virtually replaced coal in cooking and heating, significantly improving outdoor air quality in major urban areas, as well as indoors in all areas. Residential gas use now makes up the second-highest share of total gas consumption. With residential gas use relatively mature, growth rates in this sector are unlikely to be matched in the future. Indeed, growth has slowed in recent years, to 5.5% per year between 2000 and 2004. Owing to government promotion and support, a relatively high proportion of gas is used in the residential sector (31% in 2004) compared with other IEA countries dependent on LNG), such as Spain and Japan (both 12% in 2004). This places a strain on LNG supplies because the majority of the gas is used for space heating, which has a very seasonal usage profile.

Figure 51 Korean gas consumption



Source:IEA.

Table 29 Korea's consumption of natural gas by sector, 1990 to 2004

Units: Mtoe	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Electricity generation	2	4.2	5.4	6.3	4.9	5.7	5.8	6.7	7.6	7.6	10.6
Share	75%	51%	50%	48%	40%	38%	35%	37%	37%	35%	42%
Residential consumption	0.5	2.7	3.6	4.4	4.5	5.8	6.2	6.4	7.9	8.5	7.7
Share	17%	33%	34%	34%	37%	39%	37%	35%	38%	39%	31%
Industrial consumption	0.1	0.5	0.7	1.2	1.6	2.0	2.9	3.1	3.4	3.7	3.9
Share	3%	7%	7%	9%	13%	14%	17%	17%	17%	17%	16%
Other	0.1	0.8	1	1.1	1.1	1.4	1.8	2	1.8	1.8	2.8
Share	5%	10%	9%	9%	9%	10%	11%	11%	9%	8%	11%
Total	**2.7**	**8.2**	**10.7**	**13**	**12.2**	**14.9**	**16.7**	**18.2**	**20.7**	**21.6**	**25.1**
Total (bcm)*	**3**	**9.3**	**12.2**	**14.9**	**13.9**	**16.9**	**18.9**	**20.5**	**23.4**	**24.3**	**28.7**

*Consumption values in bcm are calculated using a different methodology from values reported in Mtoe.

.Sources: Energy Balances of OECD Countries, IEA/OECD Paris, 2006 and Energy Policies of Korea (IEA, 2007)

At 16%, total industrial demand for gas is low, while oil use in the sector is among the highest in the IEA. One of the reasons for this is that the government has only recently decontrolled pricing in the oil sector. Price controls had in the past given oil a competitive advantage over LNG, which is priced according to international

Table 30 **Korea's LNG imports by source, 2001 to 2005**

Units: 1 000 tonnes	2001		2002		2003		2004		2005	
Qatar	4 942	31%	5 151	29%	5 838	30%	5 896	27%	6 228	28%
Indonesia	4 028	25%	5 020	28%	5 137	26%	5 410	24%	5 565	25%
Malaysia	2 253	14%	2 301	13%	2 808	14%	4 594	21%	4 708	21%
Oman	3 928	24%	4 061	23%	4 810	25%	4 443	20%	4 335	19%
Brunei	591	4%	769	4%	548	3%	899	4%	594	3%
Others	422	3%	525	3%	293	2%	911	4%	874	4%
Total	**16 164**		**17 828**		**19 434**		**22 153**		**22 304**	

Source: Country submission.

oil markets. Now that the reform of oil pricing is almost complete, growth of gas consumption in the industrial sector between 2000 and 2004 has averaged 7.4% per year and growth has continued to be strong in 2005 and 2006.

Supply

Korea is the second-largest importer of LNG after Japan. In contrast to Japan, almost all Korean LNG supply is imported by one company, Korea Gas Corporation (KOGAS), the state-owned monopoly, making it the largest commercial LNG buyer in the world.

In 1998, the Korea National Oil Corporation (KNOC) discovered the Donghae-1 gas field in Korean waters which started production in July 2004. While significant as the first source of domestic gas, the field provides less than 2% of annual gas consumption.

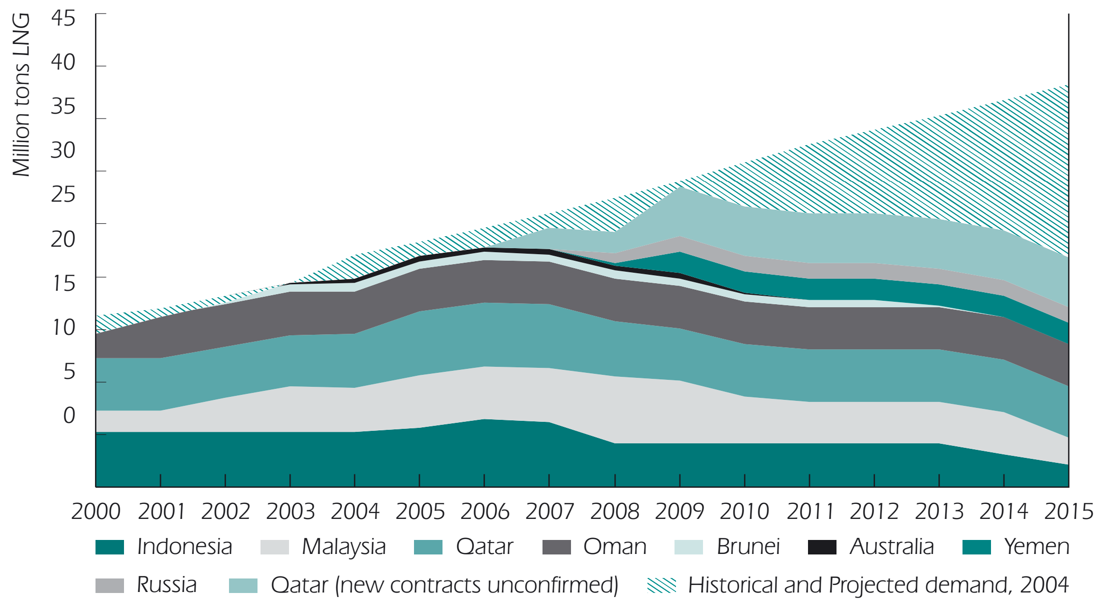
Because of its extremely high dependence on imported gas supply, Korea has traditionally placed security of supply at the top of its policy agenda. KOGAS imports from Qatar, Indonesia, Malaysia, Oman, Brunei and others including Australia, Egypt, the United Arab Emirates (UAE) and Nigeria.

Most LNG imports into Korea are delivered according to long-term contracts, usually 20 to 25 years in duration. As has been standard until recently, long-term supply of LNG to Korea is organised on a take-or-pay basis. All contracts are linked to international oil product prices, but approximately one-third also apply an S-curve in the formula. These contracts were designed to insulate buyers from high oil-driven gas prices but provide insurance to suppliers to cover the high investment costs of LNG infrastructure. Long-term contracts have allowed Korea to ensure security of supply through binding supply agreements, but put the onus on Korea to secure downstream demand.

Korea is more active in the spot LNG market than its neighbour, Japan, largely because of Korea's very seasonal demand for gas. Korea buys spot gas in winter in addition to its take-or-pay commitments, which are sufficient for gas demand in the summer.

Korea has been reviewing several major regions for upstream investment, including the Caspian and Russia. Recently these efforts have focused on major pipeline supply sources in Russia – Kovykta gas in the Irkutsk region, Chavyanandgas in the Sakha Republic and the Sakhalin Islands gas

Figure 52 **Korea's projected gas demand and contract cover, 2000 to 2015**



Note: 2 contracts with Qatar were being finalised at the time of printing for a total volume of 42mtpa, starting in 2007 and 2009.
Source:Country submission, industry information and KEEI demand forecasts

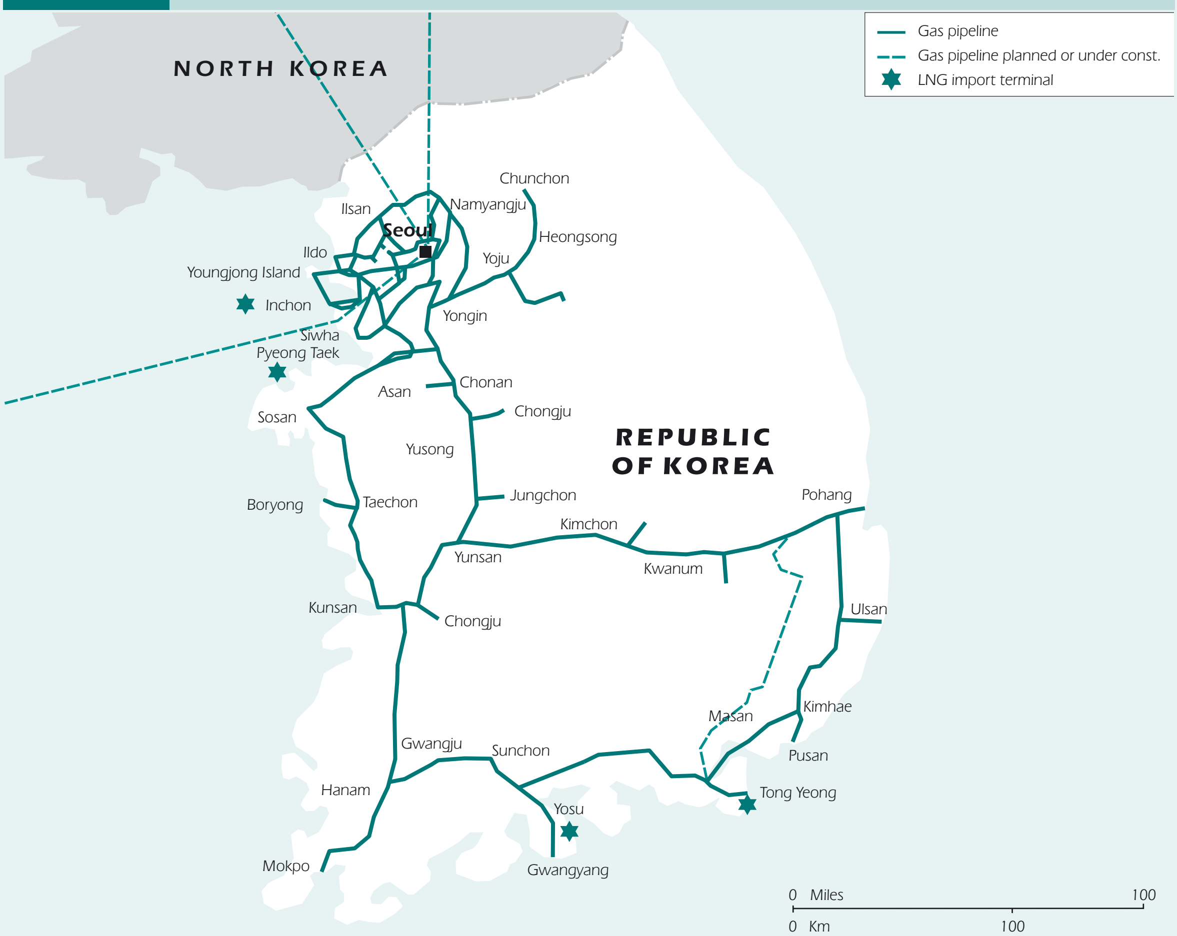
fields. Different options have been under review for over 20 years, but the Kovytka option seems to be forwarded. The pipeline route would transport gas via China, from where it would be transported across the Yellow Sea, supplying an expected 10 bcm per year to Korea. China National Petroleum Corporation (CNPC) and Russia's Gazprom signed a memorandum of understanding in March 2006 outlining the route, volumes and possible timetables for three possible pipelines (West Siberia and Sakhalin could be the other sources of gas). However, no firm plans have been made. In the meantime, LNG will continue to supply nearly all of Korea's gas needs. In recent years, KOGAS, the state-owned gas company, has changed its policy of signing long-term take-or-pay deals to a more flexible policy that relies increasingly on shorter-term contracts and spot purchases. As a result, projected gas demand compared to existing long-term contracts indicates a growing supply gap, as shown in Figure 52. Projections indicate that the shortfall may be as much as 10.9 bcm per year (8 mtpa) by 2010; in addition, 1.4 bcm per year (1 mtpa) of existing LNG contracts that will have to be renewed by that time.

In addition to reduced long-term contracting, events in Indonesia have also added to concerns about future security of supply. Recently, there have been problems with LNG exports from Indonesia, as discussed earlier. Indonesia accounts for 25% of supply to Korea and a similar proportion of supply to Japan, leaving the two largest LNG importers in the world looking to back up their Indonesian supply commitments with supply from other sources. This situation has also put pressure on the global LNG market at a time when Korean demand is increasing and old LNG contracts will soon be coming up for renewal. Kogas is trying to secure two long-term supply deals from Qatar at the end of 2006, totalling 5.7 bcm per year (4.2 mtpa). The first one started delivery in 2007 and the other is expected to start in 2009. These would be the first long-term deals after the company's virtual monopoly on LNG imports was re-instated in summer 2006.

Expanding infrastructure

Korea's gas infrastructure is constantly expanding to accommodate the rapid increase in demand. Korea has four LNG import terminals, three owned by KOGAS and one by POSCO, a large steel manufacturer. Total import capacity is 82 bcm. The gas trunk-line network provides gas to 75 cities and regions. The proportion of the population with access to a grid connection is 69%. Grid connection continues to expand, but slowly.

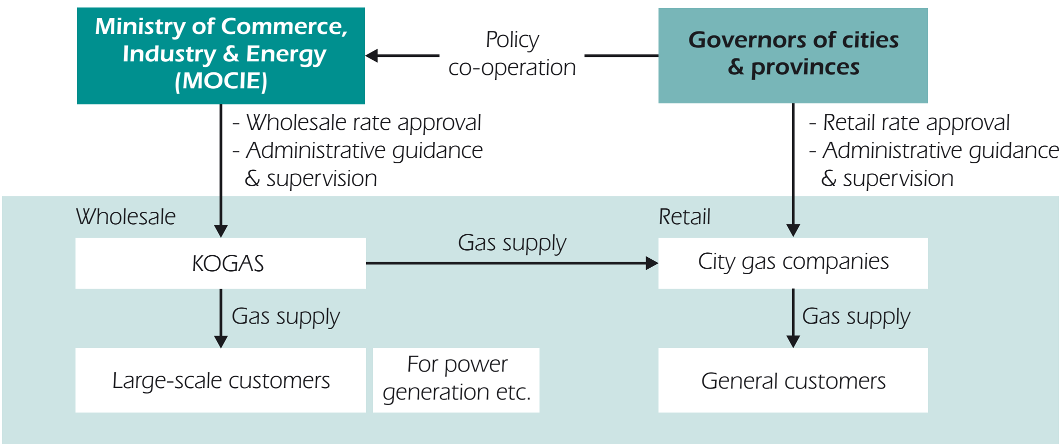
Figure 53 **Korea's gas transport network**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: *Energy Policies of Korea* (IEA, 2007).

Figure 54 **Korea's natural gas industry structure**



Source: Country submission.

Industry organisation and policy

Korea's domestic gas sector came into being in 1983 as a result of government efforts to promote diversification away from coal and oil in the domestic sectors. Korea's natural gas business was classified into a wholesale sector and a retail sector through the Korea Gas Corporation Act and the City Gas Business Act. At this time, the government set up KOGAS as a state-owned company to control all aspects of the wholesale natural gas industry.

Under the terms of the Korea Gas Corporation Act, the Ministry of Commerce, Industry and Energy (MOCIE) provides administrative guidance and supervision for KOGAS. In turn, the company is granted a monopoly to import, store and distribute gas through main trunk lines in Korea. Both the city gas companies and power companies buy gas directly from KOGAS. The city gas companies are overseen on the municipal level by governors of cities and provinces. Each of the 33 city gas companies has an exclusive supplier's licence for its region and is therefore a geographically defined monopoly. There are seven city gas companies operating in the Seoul metropolitan area with approximately seven million customers between them.

KOGAS and the various ministries have overseen the successful development of the gas industry in Korea from 1983 to 1999. The gas industry was developed with a strong focus on security of supply. The annual gas consumption growth rate from 1990 to 2000 was 20%, reflecting strong policy measures in support of diversification away from oil. This was achieved at a cost, as Korean gas prices are among the highest in the IEA, in large part because the country relies almost entirely on imported LNG. Towards the end of the 1990s, government policy regarding natural gas shifted from its overwhelming focus on energy security towards encouraging better economic efficiency.

Restructuring and liberalisation

The Basic Plan for Restructuring the Gas Industry was announced in November 1999 with the aim of enhancing competition in the gas sector. The plan was submitted to the national assembly at the end of 2001 and foresaw the splitting of KOGAS into three subsidiaries, two of which were then to be sold. The law recognised KOGAS as a monopoly that should be exposed to competition. As a means to reduce its market share to spur gas market competition, KOGAS was prohibited from signing more long-term contracts so that other companies could enter the market. In addition, the plan stipulated that open access would be implemented on LNG receiving terminals and pipelines. The retail sector currently comprises many regional or local monopolies that are not able to operate outside their geographic area and compete with each other; competition was also to have been introduced in stages to the retail market after the wholesale sector had been liberalised. The partial privatisation of KOGAS before separating it into different private entities led to an initial public offering of 43% of its equity that was completed in November 1999. The original liberalisation plan included the establishment of a regulatory commission specifically for the gas industry. Currently, the Fair Trade Commission (FTC) handles general business oversight, but there is no gas industry regulator.

Since 1999, the original reform plan has been postponed indefinitely. The decision not to proceed with reform partly stems from California's experience with liberalisation of its energy sector and the subsequent blackouts. Although a new plan is currently being prepared, no plan has been released nor is there a date for when the new plan is to be released. At the end of 2004, the government had a 26% equity stake in KOGAS. The other major owners were KEPCO (24.5%) local governments (9.9%) and private investors (38.8%). KOGAS is listed on the Seoul and New York stock exchanges.

Despite the lack of an industry-wide restructuring plan, there have been changes to the industry that open it up to players other than KOGAS. Some companies are able to negotiate in order to import gas directly if it is for the company's "own use". In 2005, the Korean steel company Posco completed an LNG receiving terminal at Gwangyang in the southern part of the country. Together with K Power, a joint venture between SK and BP, Posco has contracted to import 1.6 bcm per year of LNG. In the first deal of its kind, Posco has negotiated third-party access rights to the KOGAS high-pressure system from Gwangyang to Pohang. A further large industrial group, GS, is currently expanding its gas-fired power generation facilities and has also secured a licence to import LNG.

Demand outlook

Gas use is expected to grow by more than 60% between 2006 and 2020. The city gas sector (including industrial, commercial and residential sectors) is expected to provide the bulk of the significant growth in gas demand over the period to 2010 and beyond. The government forecasts that with the planned growth of nuclear power, the share of gas used in power generation will decline. Within the city gas sector,

Table 31 Korea's annual natural gas demand outlook, 2006 to 2020

						Average annual growth rate	
	2006	**2007**	**2011**	**2015**	**2020**	**2006-2020**	**2006-2011**	**2006-2015**
Power	14.4	16.6	18.8	13.9	14.4	0.01%	5.50%	-0.40%
Share	42%	44%	42%	30%	26%			
City gas	19.4	20.8	26	31.7	40.5	5.40%	6.00%	5.60%
Share	58%	56%	58%	70%	74%			
Total	**33.8**	**37.4**	**44.8**	**45.6**	**54.9**	**3.50%**	**5.80%**	**3.40%**

Source: MOCIE Eighth Long-Term Natural Gas Supply/Demand Plan.

industrial consumption is expected to grow faster than the sector as a whole. As industrial demand volumes are much more stable throughout the year than residential demand, this will help temper seasonality. Nevertheless, the forecast reduction in market share of gas used for power generation is likely to, on balance, increase the seasonality of the country's gas usage.

Germany

Supply

Germany provides approximately 18% of supply from domestic production, almost 20 bcm per year. Domestic production has declined from a peak of 22.3 bcm in 2003. Russia accounts for 42% of imports with the balance divided between Norway (29%), the Netherlands (24%) with Denmark and the United Kingdom supplying small volumes.

Unlike the other large gas-importing countries in Europe, such as Italy, Spain, France, the United Kingdom and Turkey, extremely limited information is publicly available concerning daily gas flows and import capacity utilisation in Germany. Where this information is available, *e.g.* from Norway, we can see that – despite high prices – only around half of Germany's current import capacity from Norway appears to be actually used (IEA, 2006).

Nord Stream, a direct pipeline under the Baltic Sea between Russia and Germany, is slated to come on line in 2011 with an additional 27.5 bcm of capacity. According to the partners, this USD 11 billion project is intended to enhance the security of German gas supply by bypassing transit states.

Most imports to Germany are made as part of long-term gas supply contracts that are pegged to the price of oil products. Information on the physical flows is sketchy as there are many physical swaps between locations so that the gas does not always flow physically along the contractual path.

Demand

Germany is the largest gas market in continental Europe. Indicative 2006 data suggest that it has surpassed the United Kingdom as the largest in the European Union. Size and a fair level of diversity in its supply should act to strengthen Germany's energy security, but the presence of different networks operating gas qualities could be seen as dividing Germany into more vulnerable zones.

Natural gas accounted for about 23% of total primary energy supply (TPES) in 2005. Consumption totalled 90.0 bcm in 2003 and about 91.7 bcm a year in 2004 and 2005. The largest share of consumption is in the residential sector, which comprises 47% of the market while the industrial sector accounts for 18%.

Because of the high residential use, German gas consumption is highly dependent on the weather – demand in January 2006 was 2.7 times that of August 2005. Seasonality is managed through gas storage as well as supply flexibility (see "Security" section for a discussion of gas flexibility). Currently, Germany has gas storage capacity equivalent to about 80 days of Germany's average demand.

Demand outlook

Residential gas demand per capita is expected to fall starting in 2010 for the next two decades as the energy efficiency of buildings improves. Some 22% of total gas consumption is used to generate electricity and new gas-fired power stations are planned in a number of locations. Germany must legally shut down its remaining nuclear power stations. The government priorities for a low-carbon future also signal a shift away from coal- and the few remaining oil-fired power generation.

Nuclear will be phased out in Germany through legal action and coal investment may be challenged by either policy action or policy inaction. In such an environment, the future gap between power supply and power demand will be filled by the "default option" – an increase in natural gas. Gas-fired generation is expected to increase from 65 TWh to 150 TWh between 2005 and 2020.

As in other IEA countries, power grid load is likely to grow more volatile as demand patterns change and intermittent generation increases. This will require the presence of a large idle capacity of variable, reliable backup generation – in the absence of hydroelectric generation, this role will be filled by natural gas.

Market structure

The structure of the German gas industry is relatively complicated because the system was conceived as a marketing network to aggregate demand in Germany for the development of large import projects. The marketing operation was historically organised as a series of regional monopolies with pyramidal demand structure – many small consumers served by fewer larger ones.

At the top of the pyramid are the three key players, who own and operate the regional trunk pipelines essential for import/export competition in the German gas market. The pipelines are owned by E.ON (which controls 55% of the German market by volume) Verbundnetz Gas (VNG, 10%) and Wingas (11%). The other major player in the German gas industry is RWE (10%). Only E.ON and Wingas are able to compete across the country although even then not necessarily in all geographic regions.

Table 32 German domestic trunk pipelines

Name	Capacity (bcm per year)	From	To	Start	Owner	Share
MEGAL	22	Czech Republic	France	1980	E.ON Ruhrgas	50%
					Gaz de France	43%
					OMV	5%
					Stichting Megal	2.0%
TENP	7	Netherlands	Italy	1974	E.ON Ruhrgas	51%
					Snam Rete International	49%
MIDAL	12.8	North Sea (Emden)	Ludwigshaven (near Switzerland)	1993	Wingas	100%
STEGAL	9.8	Czech Republic	Germany (MIDAL, JAGAL)	1992	Wingas	100%
	16.6 total (loop)	Connection to JAGAL	Connection to MIDAL	2006	Wingas	100%
NETRA	21.4	North Sea (Dornum)	Wilhelmshaven	1995	E.ON Ruhrgas	41.7%
					BEB	29.6%
					Statoil	21.5%
					Hydro	7.2%
JAGAL I	23.7	Poland (Oder)	Brandenburg	1996/7	Wingas	100.0%
JAGAL II	23.7	JAGAL I	STEGAL	1999	Wingas	100.0%
RGH	3.0	MIDAL	Hamburg	1994	Wingas	40%
					E.ON	60%

Sources: Company websites, country submission.

The price of third party access to these pipelines in the future may determine the success of the competitive gas market in Germany (see Table 32). The degree of price regulation of these pipelines is not yet established, pending a decision by the regulator concerning the degree to which some pipelines might compete with each other, therefore perhaps not constituting a monopoly (perhaps a duopoly). Until this decision is taken, trunk pipelines are not subject to regulated third party access tariffs.

Gas hubs and transparency

The government issued two pieces of legislation in the summer of 2005 based on the new Energy Industry Act with the primary focus on network regulation and unbundling of operations into separate legal entities. One, the GasNZV, is intended to ensure transparent and non-discriminatory access to the pipeline network (where applicable). The second, GasNEV, lays down a binding computation method (where applicable) for the transit fees for which approval must be obtained.

The BEB hub in the North West of the country is the only hub in Germany with any significant liquidity. Co-incidentally, BEB is the only pipeline network not majority owned by only one holding company with a gas trading subsidiary.

Several hubs have been founded in the past with limited success. For example, the Eurohub in Bunde operated for several years with minimal trading volumes and then failed due to a lack of liquidity. Too few players were able to get access to the pipeline system so there was insufficient demand for hub services.

Recently, E.ON has launched a "choice market" in northern Germany and also seems to be taking measures to increase the liquidity on its other transportation network subsidiary by combining the many balancing zones into a few.

Liquid trading hubs can rarely develop if all counterparties have to trade with the incumbent (as in the case of the choice market). As expected, few new players have so far proved willing to trade on this market when compared with the BEB hub. Commercially, it makes little sense to buy from the E.ON holding company in order to use its own grid to compete for market share to serve its customers.

At the same time as appearing to make considerable concessions to the cause of promoting a liquid gas market in Germany, E.ON also introduced a "price promise" whereby the company will undercut all competitors in Germany.

Important developments towards competition

The development of a secondary market has been stifled due to the types of contracts being signed between suppliers and consumers. However, the regulator ruled in April 2006 that contracts which locked companies into buying all their gas from one supplier for long periods of time were anti-competitive. Further to the ruling, suppliers cannot sign two-year contracts if they cover more than 80% of total annual volume and four-year contracts if they cover more than 50%. This was probably the most important ruling in the past ten years of gas market "liberalisation" in Germany.

Germany is one of the few countries reviewed in this section on IEA country gas markets where the ownership and operation of regional pipeline systems by the major gas marketers is allowed. Gas companies currently own and operate the pipeline systems needed to transport gas from the point of purchase to the point of sale to fulfil the contracts. Experience from other IEA countries suggests that this is likely to be a major factor in preventing liquid markets from developing. It is clear that if a trading company and the network manager are owned by the same financial entity this will create financial incentives for favourable access conditions for the group company.

In compliance with the new Energy Industry Act, which requires legal and management unbundling, the major gas utilities have each established separate legal entities to operate the transmission systems. The regional and local distribution networks are run by spin-offs of regional and local distributors, except where these networks supply fewer than 100 000 customers. The competition authority, the Bundeskartellamt and the Bundesnetzagentur (BNetzA) are responsible for ensuring that these companies operate independently from their parent supply companies. Both entities can investigate and force action on their own or when another company files suit.

After fighting what some observers have called a "legal rearguard action" the German incumbent companies use of the "single contract" model was ruled illegal by the regulator in late 2006. Trading within entry-exit zones (or balancing zones) is now the only legally accepted method of gas trade. Supplier switching under the new two-contract model will be facilitated by an arrangement under which capacity reserved with one supplier is automatically transferred to another with the gas supply contract – this will emulate the "rucksack principle" trialled in Austria.

Customer switching

The rate of customer switching is low in Germany – 302 customers switched supplier in 2005. The regulator is currently working on standardising the process to a uniform automated process across Germany. Lower switching levels are synonymous with lower transparency and competitive pressure than in markets such as the United Kingdom which enjoys the highest customer switching rates in Europe. The efforts to standardise and automate customer switching should improve transparency.

The German system is designed for marketing gas vertically from the import point in Germany to the burner tip. Under this model, there is little incentive or need to share information outside of the value chain. This is to be compared with a competitive market in which the independent network operator has a clear incentive to advertise its services.

Regulation

Regulation is carried out at the federal level by the BNetzA, the former Regulatory Authority of Telecommunications and Post (RegTP), an agency subordinate to the BMWi. Regulation of entities entirely operating within a single Land (or province) is done by regulatory agencies in that Land, except where it has conferred these powers on the BNetzA.

The BNetzA has powers to ensure non-discriminatory grid access ex post and to approve ex ante transit fees. Under the EnWG, it has power to monitor abuses, *i.e.* to forbid grid operators from engaging in practices that constitute an abuse of their market position. Recent rulings by the regulator have seen transportation charges reduced by up to 18% in some networks which should be one factor which could improve competition.

Regulatory coverage is still patchy, with all-important trunk-lines excluded from the price regulation system pending a decision by the regulator, as noted earlier.

Gas quality

There are several separate networks in Germany which for historical reasons each carry different gas qualities. This effectively sub-divides the country into

Figure 55 **German gas transport network**

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source:The Petroleum Economist Ltd..

regions, reducing Germany's security of gas supply when compared with one national gas market.

For the same historical reasons that underpinned the development of the gas sector, regional gas systems are operated with the quality of gas determined by the source – Norwegian gas having a higher calorific value than Russian which is in turn higher than Dutch low-quality gas. The three gas qualities are distinct so individual gas networks only carry one of the three.

Practical solutions exist; for instance it is generally accepted that the two higher quality specifications of gas, Norwegian and Russian, could be mixed and carried in the same networks. Furthermore, quality conversion facilities could be installed at points where different gas-quality networks intersect, thus creating a single market for gas.

Import infrastructure

Each of the existing offshore import pipeline systems is owned by a different consortium of private companies, usually representing the initial producer and final consumer companies. The pipelines have a total combined capacity of 54 bcm per year, but only 25 bcm passed through them in 2004 despite historically high prices.

A new pipeline project, Nord Stream, is planned to carry gas from Vyborg in Russia to Greifswald on the German Baltic coast. Construction of the approximately 1 200 km under-sea pipeline is set to commence in 2008. The first phase of Nord Stream is planned to have an initial capacity of 28 bcm per year, but it is foreseen that this will be doubled by looping the line.

E.ON Ruhrgas has owned a site on which it could build an LNG terminal at Wilhelmshaven since the late 1970's when its negotiations to import North African gas to Germany via LNG were dropped.

The Yamal Europe pipeline has a capacity to bring approximately 30 bcm per year of Russian gas from western Siberia through Belarus and Poland, but most Russian gas arrives in Germany through the Brotherhood and Transgas systems, which link western Siberian gas production to western European nations via transit through Ukraine.

Information on physical flows is not available by pipeline, so policy makers have to resort to studying contractual paths to determine source and destination of gas flows. However, the presence of several large swap arrangements between buyers means that the gas does not follow the original route of the contracts. This makes it very difficult to predict the likely flows of gas in a supply emergency (see separate section on Security).

Storage

Germany has the world's fourth-largest gas storage capacity following the United States, Russia and Ukraine. There are 43 natural gas storage facilities with a total capacity of 32.58 bcm and a total working gas capacity of 20 bcm, or about 80 days of Germany's average demand. The majority of storage facilities are operated by major gas utilities such as E.ON Ruhrgas, Wingas, VNG and RWE, as well as by independent

Table 33 **New German storage capacity (planned or under construction)**

Units: mcm	Existing storage	Expansions	Total storage
Salt cavern storage	6 703	3 648	10 351
Operational	6 703	620	7 323
Planned/under construction	0	3 028	3 028
Depleted field storage	12 365	800	13 165
Operational	12 365	670	13 035
Planned/under construction	0	130	130
Total	**19 068**	**4 448**	**23 516**
Operational	19 068	1 290	20 358
Planned/under construction	0	3 158	3 158

Source: *Energy Policies of Germany* (IEA, 2007).

facility operators and regional and municipal utilities. Most storage facility operators have signed an agreement to offer capacity on GGPSSO terms,[18] although this is a voluntary agreement rather than a binding commitment.

In the North of Germany, geological conditions are favourable for the addition of further subterranean storage facilities. In the south, geological sites are much more scarce, so new storage for German consumers is being constructed in Austria – tied only to the German grid. Fifteen salt cavern storage facilities are currently planned or under construction, with a capacity of 3.02 bcm. Capacity at existing salt cavern facilities is to expand by 620 mcm. One new depleted field storage facility is being developed, adding 130 mcm of capacity, with capacity at existing fields set to expand by 670 mcm.

Trading

Gas trading in Germany has not enjoyed the relative success seen in neighbouring Belgium or the Netherlands – currently less than 1% of domestic consumption is actively traded on gas hubs, with the majority on only one virtual point, BEB. The major reason for the lack of activity is that Germany opted for negotiated third-party access to its networks after the first European gas directive, which made it difficult to obtain firm transportation rights over a significant distance or time, therefore stifling competition. The new regulated third-party access being implemented should significantly improve trading and liquidity.

Short-term capacity from time to time becomes available and is offered to the market, often on an interruptible basis. Interruptible capacity is not sufficient for a new entrant because new entrants require firm capacity to build a business

18. ERGEG, *Guidelines for Good TPA Practice for Storage System Operators* (GGPSSO), 23 March 2005.

as a dependable supplier and because balancing services are provided by the main players at high rates compared with liquid markets in the United Kingdom. Suppliers who gain customers should inherit capacity through the "rucksack" principle. It will be interesting to see how well this principal works in practice.

The limited trading that has taken place has to some extent been around asset ownership brought about by large-scale physical swaps between the major players and the annual release programmes conducted by E.ON as a condition for its takeover of Ruhrgas. A lack of guaranteed associated transport capacity, however, meant that the first release programmes were under-subscribed and they were regarded by the market as unsuccessful.

Traders have generally found it much easier to transport gas from release programmes through the Netherlands to liquid hubs in the United Kingdom, Belgium and France than to get access to capacity inside Germany. Nevertheless, some traders have managed to purchase long-term capacity on the TENP system in the past in order to transit gas from the Belgian hub at Zeebrugge down through Germany and Switzerland to Italy.

Investment

German gas companies have maintained their commitment to the new versions of the old gas model and enhance their pipeline system infrastructure when they see fit. There is no system of auctioning unused capacity as in liquid gas markets in IEA countries. New large-scale investment in Germany is driven by the large incumbent companies because new entrants cannot get guaranteed access to long-term existing or future capacity.

For example: The Stegal, Wedal, Megal and TENP pipelines are currently being expanded by their respective owners; there was no "open season" for these projects, as is standard practice in contestable markets. The lack of open season was certainly an opportunity missed by the German policy makers to introduce some competition on those routes. Open season processes are required in contestable markets to allow third party ownership of individual routes.

A regulated open season process requires an independent network company to obtain financial commitments from multiple independent parties on an open access basis. Although important pre-qualification conditions must be met, the pipeline company then determines the need for pipeline expansion by allowing all qualified parties to bid for future ownership of capacity. After the level of interest is determined and contracts for future capacity are signed, only then does design and construction commence to the specifications of the market.

Many pipelines in the United States have been built according to the "open season" principle, as was the "Interconnector" between the United Kingdom and Belgium. In the case of the Interconnector, this has resulted in primary capacity ownership by the following companies,[19] many of whom

19. Source: www.interconnector.com

were not previously present in the United Kingdom or Belgian markets: BG (UK), BP (UK), Centrica (UK), ConocoPhillips (US), Distrigas (Belgium), EDF (France), E.On (Germany), Total (France), ENI (Italy), Essent (Netherlands), Gas de France (France), RWE (Germany), Hydro (Norway), Gazprom (Russia), Statoil (Norway).

As mentioned earlier, the lack of open season on domestic and international pipelines means that the only way that new entrants can obtain uninterruptible, long-term capacity on a domestic German network is to build their own network – an approach pioneered by Wingas in the 1990's. Clearly, for most new entrants, this is clearly impracticable and represents a substantial barrier to entry.

Pricing

In 2006, the un-weighted average wholesale prices in major IEA gas markets were USD 6.57/MBtu at Henry Hub in the United States, USD 7.08/MBtu for LNG purchased in Japan, USD 7.36/MBtu at NBP in the United Kingdom and USD 8.31/MBtu at the German border.

Gas pricing in Germany is based on the "market value" principle that the customer should pay no more or less than the cost of the competing fuel, which is either gas oil or fuel oil. Thus the prices for gas are directly linked to oil, though there is a time lag for gas prices to change following moves in oil prices. Natural gas prices to industrial consumers in Germany are set on a quarterly basis relative to the average of the previous six or nine months of prices for fuel oil and gas oil. Other elements can be reflected as well, instead of oil. For example, in a small number of cases, the price is linked to coal prices.

Domestic tariffs are linked to the price of heating oil and re-set every quarter. This type of pricing ensures volume off-take, helping achieve stable market share compared to oil. Though gas now has a substantial market share, this pricing methodology, which eliminates any interaction between gas supply and demand and the price, has not been changed by suppliers. This is perhaps the clearest signal that there is a lack of gas-to-gas competition in Germany.

Due to the "market value" principal, the consumer in Germany will pay the same price for gas as for oil products irrespective of the cost of producing and transporting gas. Therefore, reducing the transportation cost on high pressure grids is likely to result in either the producer getting more netback revenue, or the transportation provider increasing the costs somewhere else in the value chain.

A class-action lawsuit by a number of northern German consumers against the rising tariffs of a northern German subsidiary of gas major E.ON led the company to publish its gas price calculations in November 2005. Germany's second-largest gas company, RWE and a number of municipal suppliers have followed suit, publishing a detailed breakdown of their tariffs.

The IEA recently conducted an in depth energy policy review of Germany and made a number of observations. In particular, the IEA considers that Germany needs to press ahead with market reform and interconnection of the German gas markets with the rest of Europe. This will enhance supply security and diversity for German regions and the rest of Europe, such as through broader access to existing European LNG terminals. Germany will also need to monitor the increasing concentration of external gas suppliers and encourage new gas sources to enter the German market, *e.g.* by greater investment in new infrastructure including LNG import terminals in Germany based on "open season" principles. On regulation, the network regulator and competition authority will need more resources to ensure effective commercial third party access and to unbundle networks to the extent required. It also seems clear that the number of balancing zones should be reduced, ultimately to one, with a single independent system operator. Greater transparency is required, for example, pipeline operators need to provide entry and exit information on a timely public basis. Further details are provided in the upcoming publication of the In-Depth Review, planned for later in 2007.

United Kingdom

In 2005, natural gas accounted for 37% of total primary energy supply, a rapid rise from 22% in 1990. The government projects that the gas share in total primary energy will rise slightly, reaching 39% in 2020. In 2004, gas-fired power plants generated 41% of the United Kingdom's electricity. This figure has seen tremendous growth in the past fifteen years from virtually zero, with the introduction of increased North Sea gas production and CCGT plant technology. Gas to power is expected to grow further, to 60% of power generated by 2020. Information on gas flows is available by entry or exit point with a 12 minute delay; this is seen as very important so that the market can make informed investment decisions.

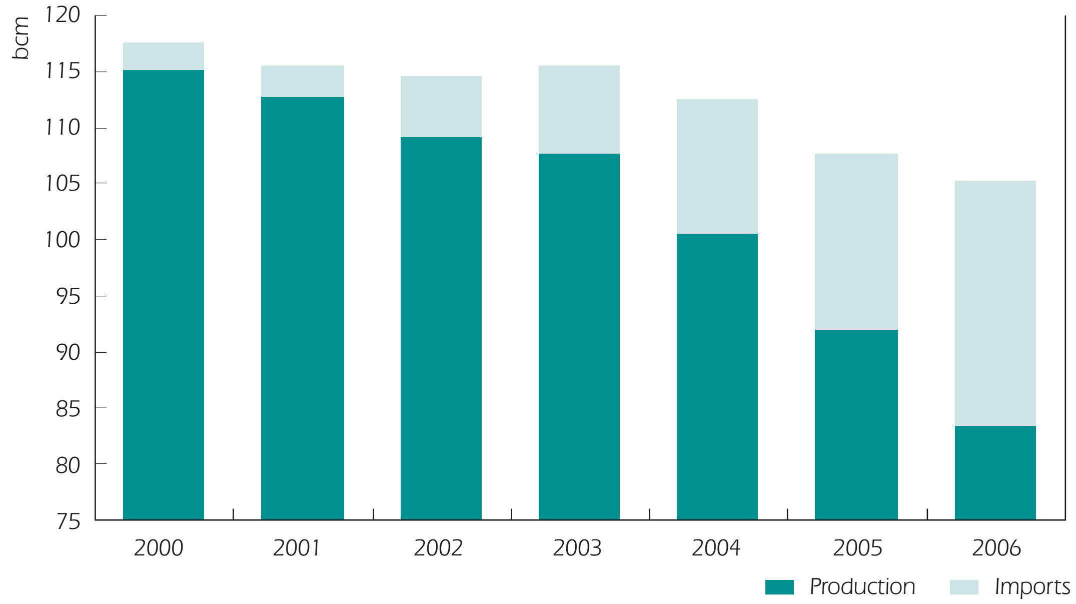
From 1990 to 2000, production more than doubled, reaching its peak in 2000. Since 2000 however, production has fallen by nearly 30% to 83 bcm in 2006. In 2004, the United Kingdom became a net gas importer. The decrease in production from the United Kingdom's Continental Shelf (UKCS) occurred more rapidly than expected. When compared with the similarly fast decline seen in the United States offshore Gulf of Mexico region, this perhaps identifies an important new trend in offshore gas production. There have been some substantial new discoveries recently and exploration continues, but offshore production is expected to decline steadily over time (the United Kingdom has produced about 65% of its total possible gas reserves), so that with forecast increased demand, imports will continue to grow, to more than 50% of demand by 2010.

Supply

Government policy strives to maximise economic production from domestic reserves. The addition of two new types of licence has been central to maintaining interest and investment. Reaction to these changes has been positive: in 2005 the highest number of licences was awarded in the United Kingdom's North Sea history.

The United Kingdom has imported gas from Norway via the Frigg system for over a decade, while LNG imports were first received in the summer of 2005 at

Figure 56 United Kingdom gas production and gross imports



Source: IEA data.

Isle of Grain. LNG import capacity is being expanded fast, with a new project at Teesside added only months ago as well as others planned (see below). In keeping with increased net import demand, several import infrastructure projects were completed as planned, just before winter 2006/07. These are the Langeled pipelines from Norway to Easington (25 bcm per year, of which the southern leg from the Sleipner field came on stream on 1 October 2006), the upgrade of the Belgium Interconnector (from 16.5 to 23.5 bcm per year, completed on 1 October 2006) and the BBL pipeline linking the United Kingdom market with the Netherlands (15 bcm per year, operational on 1 December 2006). This new import capacity together will offer an additional import capacity of 131 mcm per day, almost half the United Kingdom's consumption, (see also LNG, below).

Demand

The United Kingdom has a highly competitive downstream gas market. Although Centrica (the downstream business inherited from the former monopoly) is still the largest retail gas company, it has recently lost market share due to high levels of customer switching (see section on Recent Events). Liberalisation and the introduction of competition have shifted a great deal of gas supply activity from the public sector to the private sector. The liberalisation process is generally regarded as successful: there have been no major energy disruptions, more services are being offered and prices went down. In 2004, retail ex tax gas prices for households were 14% below the IEA average, while retail ex tax prices for industry were 25% below the average.

In 2004 the falling United Kingdom gas price trend reversed itself, partly because import and storage did not appear to keep pace with the decline of domestic production. Gas prices paid by non-residential customers almost doubled in the period between the first quarter of 2004 and the fourth quarter of 2005. For residential customers, the retail price of gas rose by 33% from the first quarter of 2004 to the first quarter of 2006. This has since proven to be a brief spike rather than a trend – prices for winter 2006/07 gas in the United Kingdom have been approximately half the level of prices in the oil indexed continental European markets, largely due to completion of new import infrastructure.

LNG

The Isle of Grain terminal is fully contracted for 20 years between terminal operator National Grid and BP/Sonatrach (as one shipper). National Grid is starting a phase 2 expansion with an additional 9 bcm; capacity is under 20-year contracts by Sonatrach, Centrica and Gaz de France. For both phases an open season process was employed. An additional phase 3 could be available ahead of winter 2010/11; a third open season has been held, which closed on 18 January 2006. This third tranche is subject to appropriate market interest, obtaining the necessary permissions for further site development and regulatory consents.

The Excelerate dockside LNG terminal for regasification vessels at Teesside (4 bcm per year) started operations in February 2007. It is particularly noteworthy for its very short lead time of only one year. The facility can take up to four cargoes per month. Increasing flexibility could be derived from ship-to-ship transfers of LNG. Scapa Flow, which is located within the Orkney Islands, off the northeast coast of Scotland, is seen as a good location for the operations.

Several additional import-related investments are either planned or taking place which should be operational by 2010. In Milford Haven two LNG terminals are under construction to be operational in 2007/08: one of 6 bcm per year (the Dragon LNG project, by Petroplus/BG/Petronas) and one of 10.6 bcm per year (phase 1 South Hook LNG, Qatar Petroleum/ExxonMobil/Total).

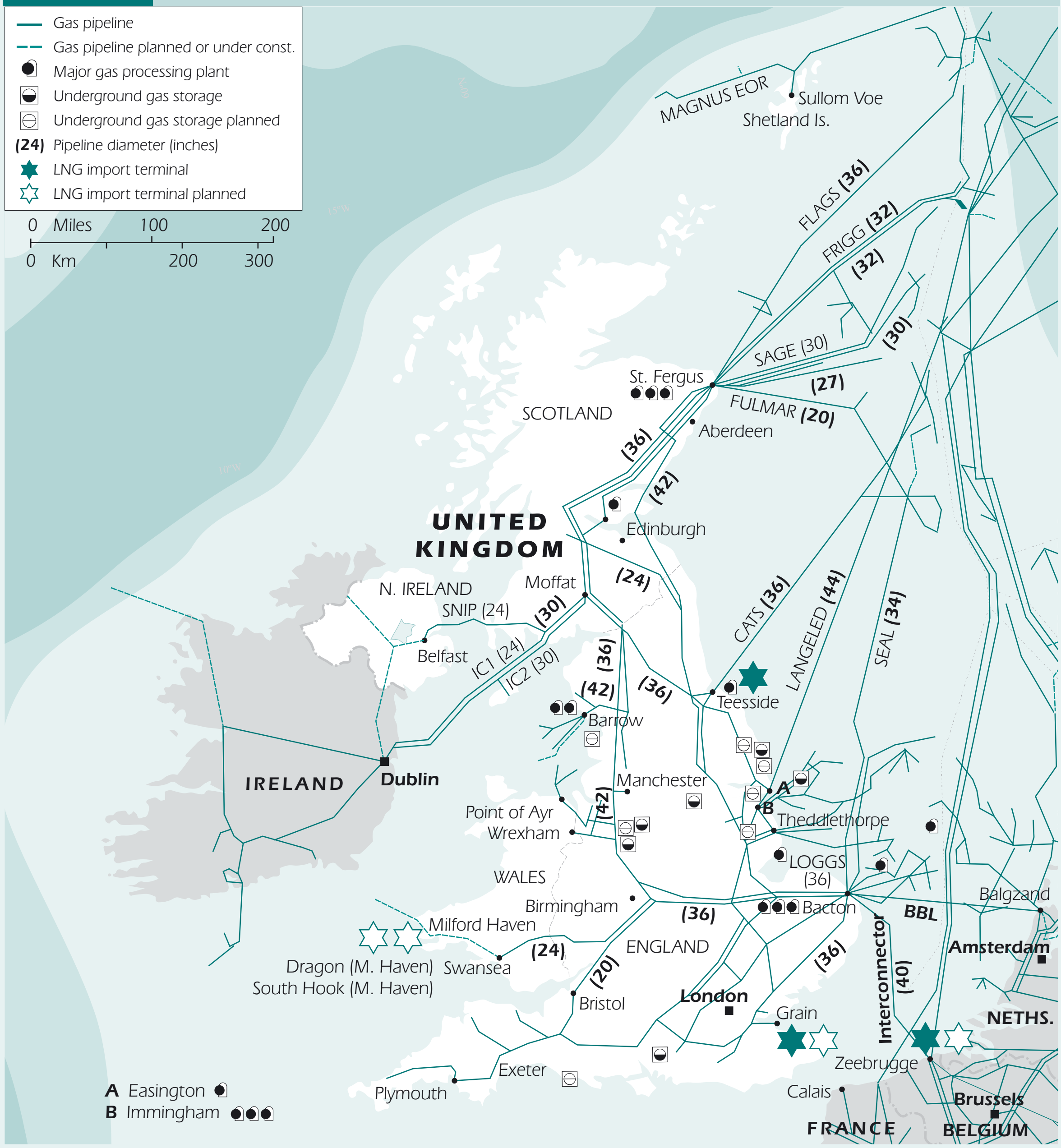
Midstream and gas quality

Substantial investment is being planned to upgrade the high-pressure gas pipeline network. Ofgem noted that gas networks face “huge challenges” over the next five years to respond to changes in the sources of gas, primarily higher volumes from LNG imports and a further increase in gas use for power.

While Norway is solely a gas exporter to the United Kingdom, Belgium both imports and exports gas via the sub-sea Interconnector (IUK) depending on the relative market conditions in the United Kingdom and on the continent (discussed in Recent Developments).

On 29 December 2005 the government published its proposal to retain the current United Kingdom gas quality specifications, which are different from those being recommended for continental Europe through the EASEE-gas proposals. The financial costs of blending or processing by producers or other parties in the market to meet the existing United Kingdom specifications are lower than changing the regulations governing gas quality plus redesigning and replacing gas appliances. Ofgem chaired a gas quality workshop on 13 September 2006 to assess whether gas

Figure 57 United Kingdom gas transport network



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: The Petroleum Economist Ltd..

quality acts as a constraint to gas supplies and further examine solutions to this potential problem.

Storage and flexibility

The offshore "Rough" storage (owned by Centrica Storage Ltd) accounts for about 76% of the available gas storage capacity. The Hornsea facility (SSE), represents 8.8% of storage capacity while Humbly Grove (Star Energy) accounts for 7%. The facilities which are used to balance shifts in demand within a single 24-hour period offer relatively modest storage volumes (1.5% of the national total) but can withdraw quickly and thus represent a large share of the combined withdrawal rate for the country (28.5%). National Grid owns five LNG peak shaving units, accounting for almost 10% of the total. The LNG peak shavers have the highest withdrawal rate: 36.5%.

The United Kingdom continental shelf still has considerable production flexibility, though this is decreasing as overall production is reduced through depletion. Nevertheless, the peak swing capacity of the UKCS by 2011/12 (200 mcm per day) added to the planned withdrawal capacity from storage in place by 2011/12 (400 mcm per day) should cover the maximum (1 in 20) peak winter demand (550 mcm per day) – assuming depletion rates are accurate.

Gas trading

Ofgem introduced the screen-based, on-the-day commodity market (OCM) in 1999 to allow shippers to balance their daily positions and National Grid to purchase and sell gas to balance the transmission system.

The National Balancing Point (NBP), a notional point at the centre of the transmission system, serves as a market place for gas. Once gas has entered the transmission system at an entry point, it can be traded at the NBP without quantitative restrictions relating to its exit point. The physical gas is traded at the NBP for balancing purposes partly through the OCM and partly through bilateral deals. The NBP is also the settlement point for exchange traded futures contracts. The NBP churn rate is around 10, meaning that each molecule of gas is traded ten times before it is delivered. Just over half the gas delivered in the United Kingdom is actually traded on the NBP with the rest delivered under long term contracts.

Netherlands

The Netherlands is a large established gas producer and exporter; 78 bcm and 55 bcm respectively in 2006. Net exports are considerably lower than this as the Netherlands is also a significant importer (25 bcm in 2006). Its peak production capacity of nearly 11 bcm per month is important in balancing supply with demand throughout the winter peak in Northwest Europe. Physical gas flow information is published on all borders, but is not yet available by pipeline.

Supply

The Nederlandse Aardolie Maatschappij B.V. (NAM), owned by Shell and Exxon Mobil, has been active in the Netherlands since before the discovery of the large Groningen field, with original producible gas reserves estimated at 2 700 bcm. The Groningen field is operated by and for the benefit of a public-private partnership which stipulates that Groningen gas must be marketed via GasTerra, whose annual profits are capped. An extra dimension of this arrangement is that the state, producers and GasTerra have agreed to prolong the life of the Groningen field by encouraging production of other, more expensive fields ("small-fields policy", codified in the Gas Act).

During the last decade many other producers entered the Dutch market, but the NAM remains by far the largest producer with its concession for the Groningen field and a total market share of almost 75%. NAM produces 50 bcm of natural gas a year, of which 27 bcm (54%) comes from the Groningen field. The development of many deposits is difficult because they are located underneath environmentally sensitive areas. NAM commenced production in the Wadden Sea area in 2007, which contains a relatively large amount of gas (approximately 20 bcm).There is no specific regulatory regime for access to upstream pipelines, only general competition rules apply.

The Netherlands has historically had a similar policy to the United Kingdom and Norway regarding offshore licensing for production acreage. However, licensing arrangements in both the United Kingdom and Norway have recently changed. Particularly relevant are changes to the treatment of Norwegian and the United Kingdom's continental shelf "fallow fields" (those reserves which are economic, but not yet produced). Changes in fallow field rules are expected to increase production in the United Kingdom's and Norwegian sectors as larger companies are forced to give up acreage that they do not find attractive to develop in favour of smaller, specialist gas companies.

Demand

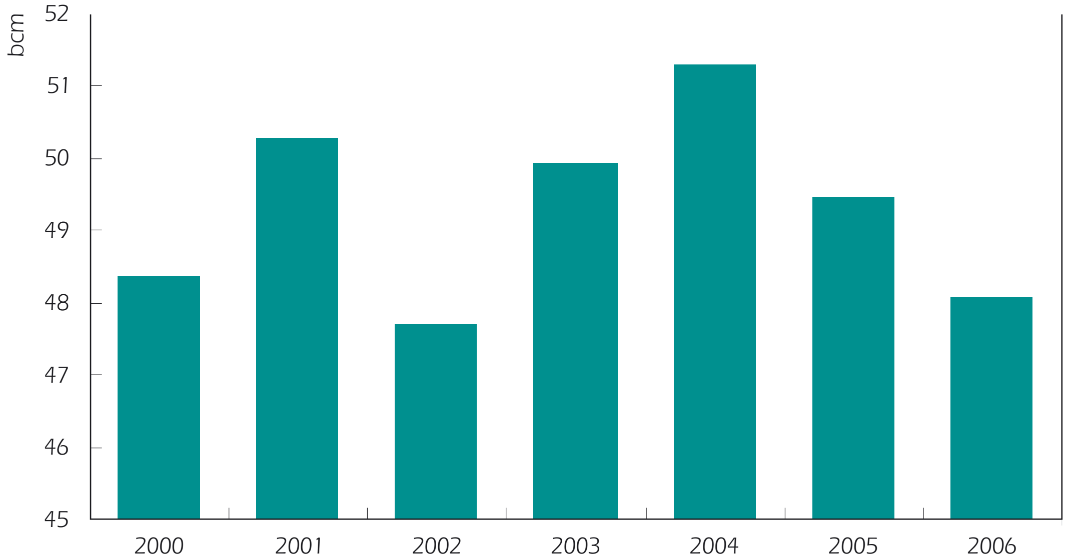
The Netherlands has amongst the highest level of gas penetration in the world. In 2005 the natural gas share of total primary energy in the Netherlands was 43% compared to the IEA Europe average of 24%. Natural gas use for power generation accounts for about 33% of total gas demand. Natural gas consumption totalled 49.5 bcm in 2005. In the same year Dutch exports amounted to 52.4 bcm, of which 31.9 bcm was to Germany and 20.5 bcm to Belgium.

The natural gas share in power generation was 60.5% in 2004. In view of this large share and the high imports, electricity prices are sensitive to changes in gas prices.

LNG

In the Netherlands four LNG terminals are being planned. The projects are at different stages. In September 2006 Petroplus International N.V. received its final environmental permit for its subsidiary 4Gas, to build an LNG terminal in Rotterdam. Its LionGas project is planned

Figure 58 **Netherlands gas consumption**



Source: IEA data.

to be completed in 2010. The permit allows for a capacity of 18 bcm per year; the terminal will initially be constructed for 9 bcm per year. Essent and ConocoPhillips have completed a feasibility study for an LNG terminal at the Port of Eemshaven in the north of the Netherlands. In March 2006 they started applying for permits. Gasunie and Koninklijke Vopak N.V. are partners in the Gate terminal LNG project in the port of Rotterdam (first phase 8 – 12 bcm per year). A final investment decision is likely by mid 2007; the terminal may be operational by 2010. In addition, Taqa – the national energy company of Abu Dhabi, the United Arab Emirates – announced in February 2007 that it is going to build an LNG installation off the coast near Rotterdam, utilising onboard regasification technology and offshore depleted gas fields for gas storage.

Midstream and gas quality

Gas – especially from small fields – may be different in composition and, consequently, may have a different calorific value. If gas of a higher calorific value needs to be converted to gas of a lower calorific value, the shipper will need to contract quality conversion. There are four standard Gas qualities: H, L, G+ and G. These four types of gas are transported through separate but interlinked transmission grids. Cross-subsidies between different consumer groups are prohibited, but the costs associated with quality conversion have been socialised by 50%, to create more of a level playing field for parties without direct access to L-gas.

The throughput of the transmission system is large and growing as a result of increasing international gas flows. In 2005, 95.6 bcm was transported, of which two thirds crossed at least one border, double the level of domestic gas consumption. Increasing imports are expected from Russia and Norway and via LNG, as European gas consumption increases while production declines. The expected increase in transit, imports and exports has to be accommodated with investments in both entry and exit capacity at the borders and reinforcements of pipelines. In short, as with many IEA European countries, the Dutch pipeline network will probably need to be reshaped substantially within the next decade.

The BBL (Balgzand-Bacton Line) started transporting gas from the Netherlands to the United Kingdom on 1 December 2006. The total transport capacity is 16 bcm per year, based on the total capacity sold during the open season in 2003. BBL Company, owned by Gasunie (51%), E.ON Ruhrgas (20%), Fluxys (20%) and OAO Gazprom (9%), will offer capacity on an interruptible basis when shippers do not use their contracted capacity for a limited time. During the open season of 2003 no structural interest was shown by shippers to transport gas from the United Kingdom to the Netherlands, but reverse flow could be made possible in the future if technical modifications are made. The BBL is exempted from TPA obligations.

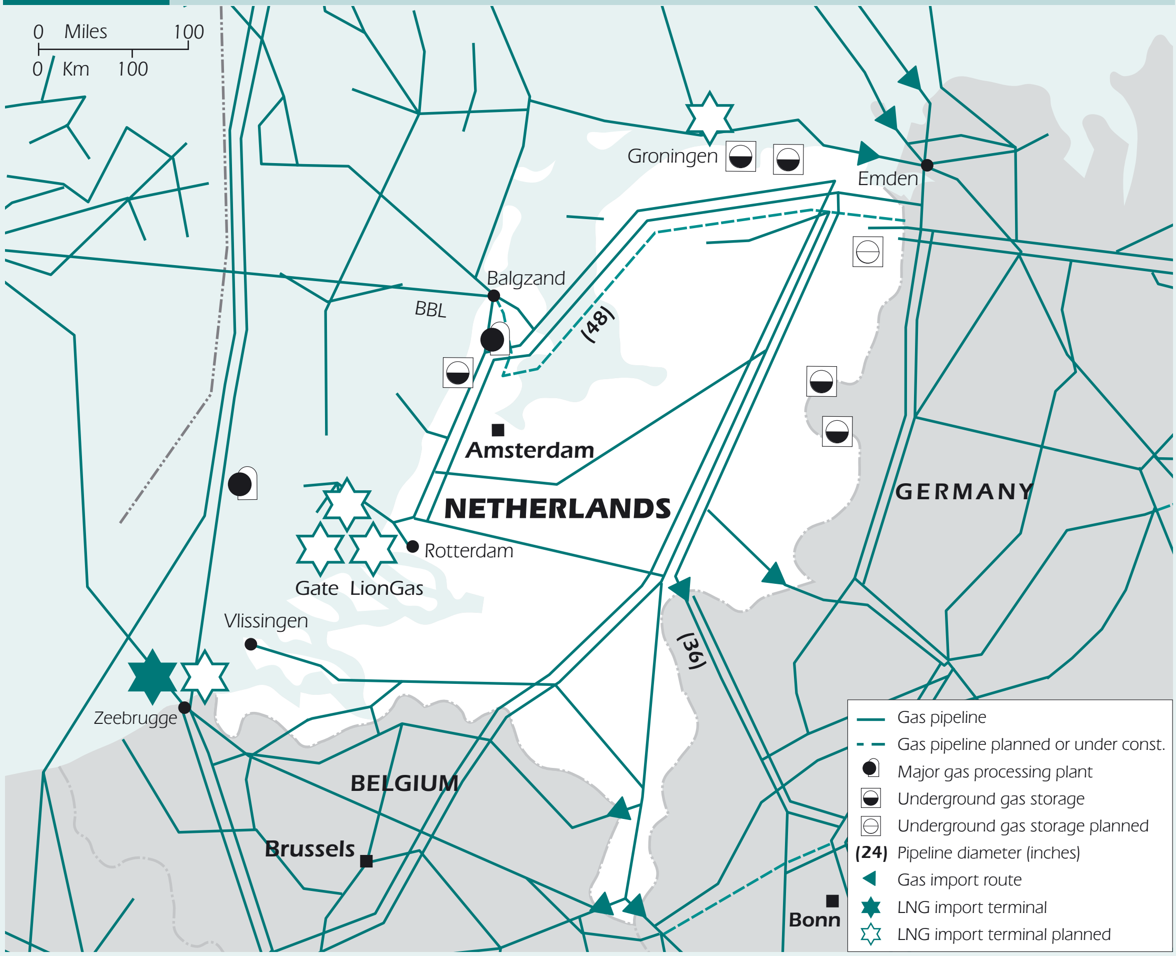
Another interconnection, the Nordstream pipeline, is planned for completion in 2010, to transport gas from Russia directly to Germany. Nord Stream is a joint project of four companies: OAO Gazprom (51%), Wintershall AG (20%), E.ON Ruhrgas AG (20%) and Gasunie (9%). Initially one pipeline will be built with a transport capacity of around 27.5 bcm per year. The second pipeline is planned to come on stream in 2012 to double the transport capacity to around 55 bcm a year. European TPA rules will not apply.

Storage and flexibility

The current balancing regime is based on daily balancing on portfolio basis with cumulative hourly tolerances. GTS (Gas Transmission System Company) offers shippers a certain amount of hourly tolerance as part of standard transportation contracts and refrains from imposing penalties on hourly imbalances, if these stay within the tolerance. GTS uses the prices listed on the gas exchange as a basis for the settlement of the imbalance volume. For 2007, the day-ahead APX indices for the Title Transfer Facility (TTF) price, the Zeebrugge Hub price and the NBP index will be used. The price for shortages will be determined by the highest price in the price basket; the price for surpluses by the lowest price in the price basket. This methodology is somewhat arbitrary as neither the NBP price nor the Zeebrugge prices are determined by balancing conditions in the Netherlands.

Shippers can buy tolerance from each other. However, this tolerance is not sufficient given the typical consumer off-take profiles. Serving consumers, particularly small ones, requires flexibility services. These services can be purchased from storage owners and from GTS, which has an obligation to tender the services. GTS, Nuon and AKZO/Nobel have taken an initiative to build a commercial storage facility in a salt cavern in the Netherlands.

Figure 59 **Netherlands gas transport network**



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Source:The Petroleum Economist Ltd..

There are three underground storage facilities, namely Grijpskerk, Norg and Alkmaar. In 2002, DTe issued "Guidelines for Gas Storage", which stipulate that the companies, NAM and the Bergen Concessionaries, owning the three existing gas storage facilities must make a considerable part of their storage capacity available to third parties on a negotiated access basis. They must base tariffs for their services on actual costs and relevant substitutes. New storages owned by new operators will not be subjected to regulation because only the existing ones are deemed to have a dominant market position.

Gas trading

Approximately 50 shippers have concluded a transport contract with GTS. Groningen gas is marketed via GasTerra, which also must buy small fields production if asked – it therefore has the lion's share of the Dutch shipper market. The exclusive right it has been granted regarding the Groningen field hampers effective competition in the market for low calorific gas. GasTerra does not deliver gas directly to end users in distribution networks but focuses on its core business of delivery to large consumers connected to the transmission grid, wholesaling and shipping. Plans to split the company into two, one owned by ExxonMobil and one by Shell, have been discussed for several years but not finally agreed.

The majority of gas prices are set according to the "market value principle" established in the 1960's, meaning that gas is priced according to the prices of alternative fuels. This means linking gas prices to the prices of the reference fuels for households (domestic fuel oil) and larger consumers (fuel oil). Daily published gas wholesale prices are not yet available, as the market is not sufficiently liquid. Initiatives have been taken to create a wholesale gas exchange, starting with the TTF (Title Transfer Facility). GasTerra is experimenting with sales based on TTF and NBP prices.

During 2005 the trading volume on the TTF grew by an average 9% per month, adding up to a total of around 12.5 bcm. This equals more than a quarter of the volume of gas consumed by the Netherlands. A net amount of around 4 bcm was supplied by shippers via the TTF (up from 1.3 and 2.5 bcm in 2003 and 2004).

The TTF helps to increase liquidity in the market by facilitating a spot and forward market and creating new ways to access gas. It serves as a virtual entry or exit point in the shipper's portfolio. Currently 38 parties are active on the TTF. Liquidity is increasing, but compared to the United Kingdom's NBP it is still moderate. Since February 2005, APX Gas NL has provided a real time market place facility to buy and sell within-day and day-ahead gas at the TTF. Endex European Energy Derivatives Exchange launched clearing services for TTF gas contracts on 20 October 2006.

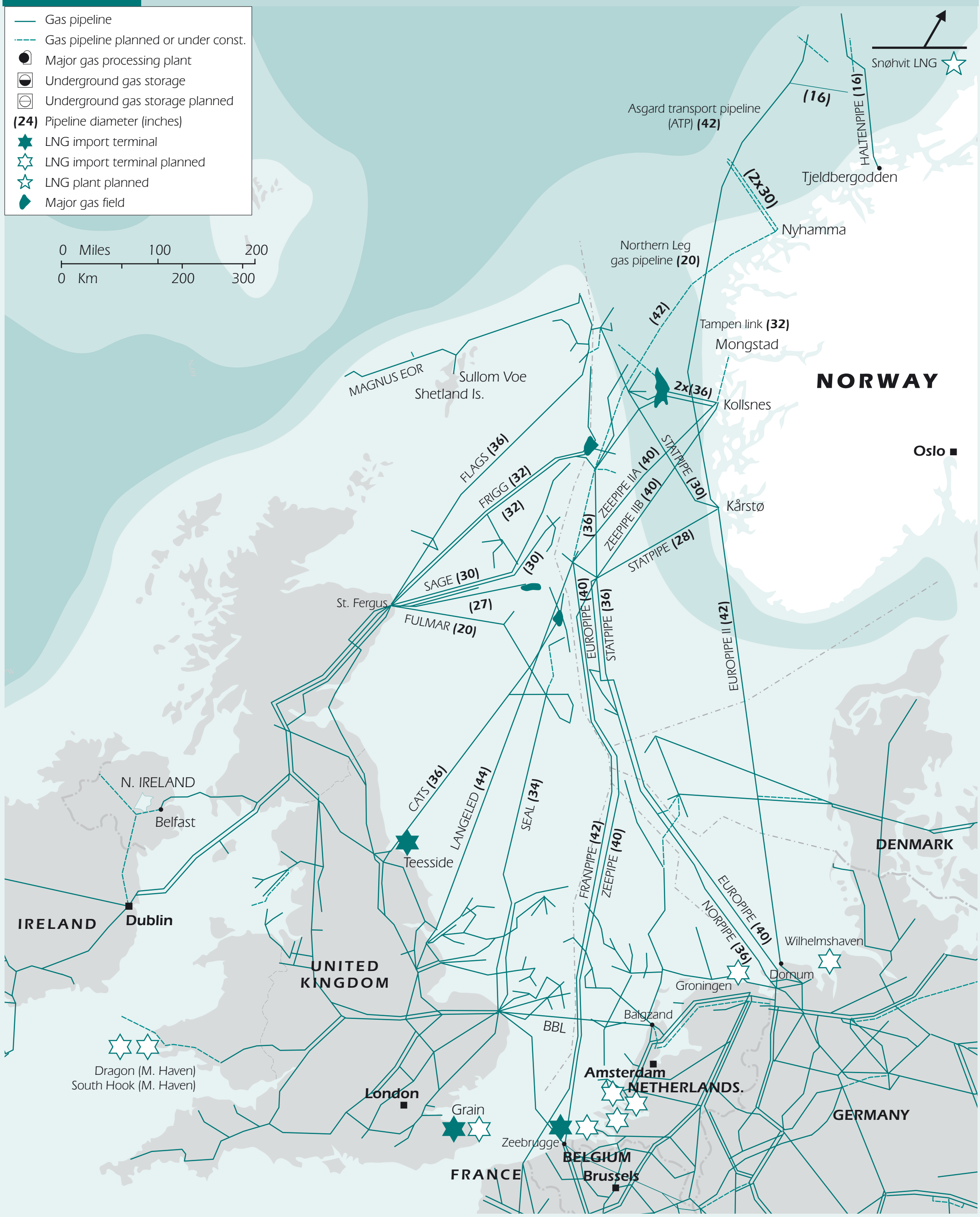
Norway

The economically efficient development of its large oil and gas resources has made Norway the third-largest exporter and sixth-largest producer of gas in the world in 2005. Over 90% of the gas produced from the Norwegian continental shelf (NCS) is exported to continental Europe and the United Kingdom; the oil and gas industry itself accounts for most domestic gas use. In 2005 Norway supplied over a third of the total import demand of the North-West European market (Belgium, the United Kingdom, the Netherlands and Germany); 18% of the gas imported by IEA Europe was produced on the NCS. A network of undersea pipelines connects Norway to Europe across the North Sea (see figure 60). Pipeline exports will be supplemented by LNG from the Snøhvit project in 2007.

Supply

In 2005 Norway exported 83 bcm of its 90 bcm production; 32.6% of exports went to Germany, 18.6% to France, 17.3% to the United Kingdom and some 8% each to Belgium, the Netherlands and Italy. The rest was supplied to Spain whilst swap contracts exist with the Czech Republic and Poland. Most gas is processed onshore before being exported. The gas sales price

Figure 60 Norway gas transport network



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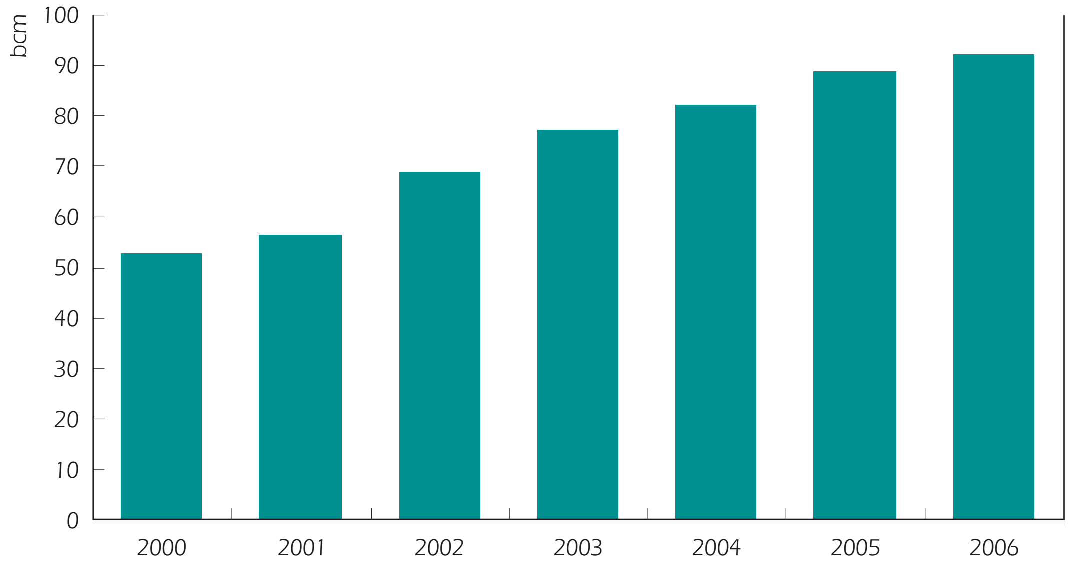
Source:The Petroleum Economist Ltd..

Figure 61 **Norwegian gas production**



Source: IEA data (December 2006 provisional).

is mostly based on delivered oil prices in the target market with the exception of the United Kingdom, where it is sold on the "NBP" gas index (explained in United Kingdom section above). Exports in 2006 rose to 85 bcm. Bringing Ormen Lange and Snøhvit on stream (see below) will make Norway the second largest gas exporter after Russia, overtaking Canada.

Following report 38 to the Storting (2003 - 2004) "On oil and gas activities" in 2003, the government has recently changed the licensing and taxation policy for upstream oil and gas activities. The main objectives of the change were the following:

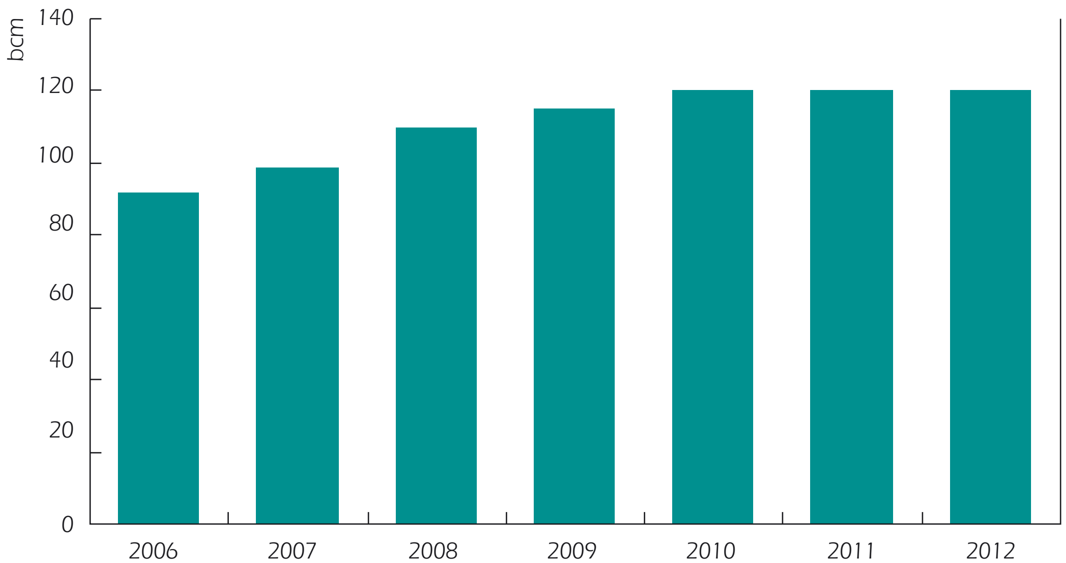
- To encourage new, smaller companies to enter the Norwegian continental shelf (NCS) and participate in award rounds.
- To encourage the speedy exploitation of awarded acreage.
- To increase exploration in mature areas with existing infrastructure.
- To increase information and choice available to companies.

The first license awards after these changes were viewed as a success, with three companies gaining acreage for the first time and one specialist "tail end" production company applying. For full details of the changes to licensing, refer to IEA Energy Policies of Norway (2005).[20]

Norway plays a leadership role in upstream technology. Recovery rates are extremely high by international standards, driven by higher gas prices and incentives for production of marginal fields; however, the costs of drilling might become a bottleneck in future exploration. Comparatively higher costs than in the

20. http://www.iea.org/textbase/nppdf/free/2005/norway2005.pdf

Figure 62 **Expected future Norwegian gas production**



Source: Ministry of Petroleum and Energy (facts 2006).

United Kingdom sector of the North Sea are driven by a combination of high environmental standards and significantly higher cost for labour. Norway imposes very high environmental performance and safety standards on the offshore industry, including regulations on exploration rigs that make it difficult for rig owners from other areas of the North Sea to offer their services in Norway.

Demand

The use of gas is limited in Norway itself, even though domestic consumption has increased from 4.2 bcm in 2001 to 5.8 bcm in 2005. Most of this gas is consumed by the energy industry itself: 80% of domestic consumption is used for oil and gas extraction. Many of today's gas applications are accordingly found close to the landfall sites of pipelines along the coast; there is almost no on-shore gas distribution network. Domestic power production is almost entirely based on hydro-generation, although Norway benefits from being part of the larger Nordpool electricity system which also uses other generation sources.

Only 1.2% of gas consumption was used for power generation in 2004. A CCGT plant at Kårstø is under construction and is planned to come on line in the autumn of 2007. It is Norway's first commercial onshore gas-fired power plant and it claims the lowest greenhouse gas emissions of any fossil fuel-based power plant in Europe. There are plans to install a CO_2 capture facility for the plant after 2009. The government and Statoil concluded an agreement in 2006 to establish the world's largest carbon capture and storage (CCS) project in conjunction with a projected CHP power plant at Mongstad. The project, which is intended to be fully operational by 2014, will have a thermal efficiency of around 80%.

Recent and future developments

The most significant recent pipeline development in Norway is the 2-stage Ormen Lange project in the Norwegian Sea. The first stage of this project saw the construction of the Langeled pipeline system from Nyhamna, Norway to Easington, the United Kingdom – the longest underwater pipeline in the world. Langeled entered operation in September 2006, ahead of time and under budget. Norwegian gas began to flow through the southern leg of the Langeled pipeline system from the Sleipner Riser platform to the United Kingdom on 1 October 2006. The second stage of the development is to bring production from the Ormen Lange field online in September 2007. This is the second-largest gas field in Norway and the first development at a water depth of 800 – 1 100 m. The Tampen Link, also to the United Kingdom, will be another new link with a capacity of about 10 bcm to be ready by 2007.

There has been a ban on Arctic drilling in Norway since 2001, pending environmental impact studies. However Norway reopened the southern part of the Barents Sea for exploration and production activity in 2003, subject to strict environmental requirements. The Snøhvit field is the first development in this area. Snøhvit is being developed for LNG export, with initial production expected later in 2007. This is a particularly challenging development with many "firsts" for the gas industry worldwide; because of this the project is currently running over budget and behind time. It will be the first export facility for LNG in Norway (and for that matter, Europe), with markets in both North America and Europe.

The concept of a gas pipeline from Norway to Sweden is under consideration. The initial annual volumes to be carried by the pipeline are expected to total some 3 bcm. Plans call for a possible investment decision in 2009, with the system being ready for start up in 2011/12. There are other development projects under consideration, such as the further development of the Troll field, by Statoil and Norsk Hydro. The need for a new export pipeline continues to be evaluated and studies of possible routes are ongoing. The United Kingdom, Belgium and the Netherlands are candidates for landfall.

Territorial issues

A recent agreement reached in 2005 between the United Kingdom and Norway on the tax treatment for the exploitation of resources at the boundary between the two countries has opened the way for their development. A similar agreement will be required with Russia before the boundary areas of the Barents Sea can be opened for exploration.

Shelf boundaries are regulated by the United Nations Convention on Law of the Sea. Since 1996 the Norwegian Government has been collecting data and mapping areas in the Norwegian Sea and Barents Sea, to find out how far the NCS extends beyond the 200-mile limit. Data collection from the Norwegian shelf has now been completed and the documentation has been handed over to the commission. If Norway's view is accepted, the NCS will be expanded by an area corresponding to half the size of mainland Norway.

Belgium

Belgium has no indigenous gas production and therefore relies on imports to meet all of its domestic requirements. Its strategic location between major sources of European gas (to its north and west) and primary markets (south and east) give the country an importance for the trade of gas in Europe well beyond its own relatively small consumption. As in other IEA countries, consumption is set to grow rapidly with the phase-out of nuclear power and its replacement with the "default option" – natural gas-fired generation.

Belgian gas market liberalisation has progressed rapidly to a point. With the landfall of the Interconnector to/from the United Kingdom in 1998, liquidity at the landfall point, the Zeebrugge physical hub, expanded rapidly. The number of counterparties active at Zeebrugge has expanded. Nevertheless, the liquidity of the hub is still dependent on the Interconnector, as domestic Belgian competition has not developed quickly. At the time of the last IEA Energy policy review of Belgium (2005), the domestic market was over 95% controlled by one company. The same company held rights to the majority of the capacity at the Zeebrugge hub.

Demand

In 2005 domestic gas use was 17.3 bcm, all met by imports. Belgium's domestic gas demand is expected to rise by 5% annually over the period 2004-2010 as the share of power demand met by gas-fired electricity increases from 25% to more than 44%. Long-term projections (to 2020) indicate that gas-fired generation will expand to 63% of power needs as nuclear power is phased out (Nuclear power currently supplies 56% of Belgium's electricity generation). This implies expanding gas-fired output from 22 TWh to 69 TWh in that time frame, (an increase in gas demand of about 8 bcm at best practice efficiency) such an increase represents a major change in the profile and location of demand and would require significant modification of the existing gas and power infrastructure. Greater gas-fired power generation is the major factor in the forecast two thirds increase in gas imports to Belgium by 2020.

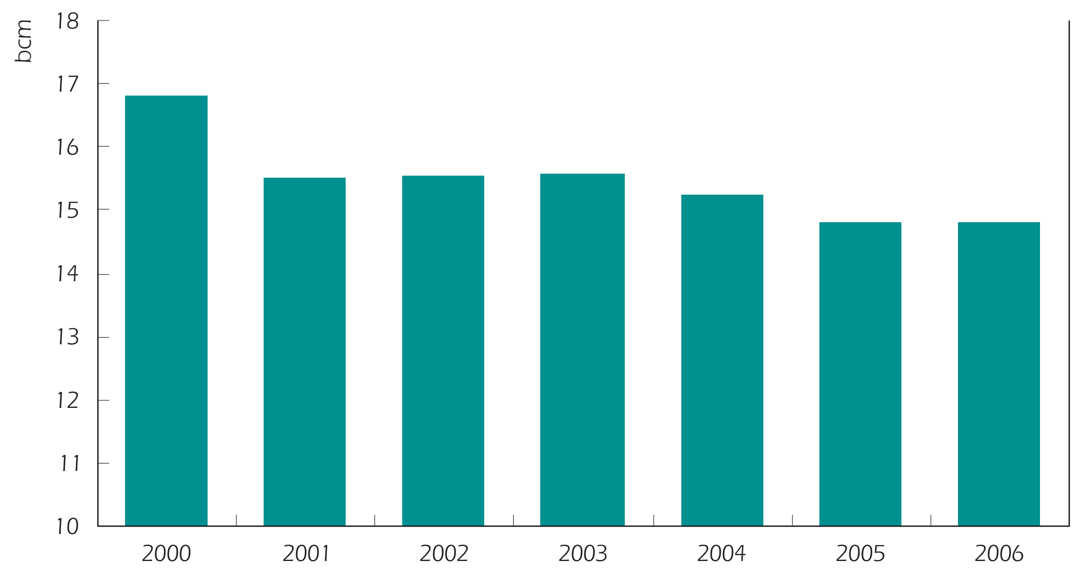
Supply

In 2006, 32% of the 17 bcm pipeline imports came from the Netherlands, 31% from Norway and 37% from other sources, including Russia (5%), the United Kingdom (2%) and 20% from Algeria. Belgium imported 2.7 bcm as LNG from Algeria. Distrigas (Suez) is the major importer, accounting for more than 90% of total imports in 2004.

LNG

Fluxys LNG (Suez) owns and operates the LNG terminal in Zeebrugge and sells terminal capacity and related services. In 2006 the LNG terminal received 54 cargoes.

Figure 63 **Belgian gas consumption**



Source: IEA Data (December 2006, provisional).

The LNG regasification and storage facility at the port of Zeebrugge has contributed to the security of Belgium's gas supply, although take away capacity inland has remained in the hands of the incumbent. Fluxys (Suez) publishes available capacity from the Zeebrugge LNG terminal into Belgium on its website. Unloading capacity at the LNG terminal was fully committed until 2006 by Distrigas and from 2007 onwards it is fully booked by Exxon/Qatar Petroleum and Suez affiliates Distrigas and Tractebel LNG. Fluxys is currently finalizing the construction of a fourth LNG storage tank and additional send-out capacity at Zeebrugge, to be in operation at the end of 2007. The import terminal will have doubled its capacity from 4.5 bcm to 9 bcm per year as from 2007. From 1 April 2007, a new multi-shipper environment will be created at the LNG terminal. In 2007 an open season will be launched to assess the interest of the market in additional terminal capacity as the pre-feasibility study is positive.

Midstream and gas quality

The domestic gas market is divided between the two qualities of gas used in Belgium, introduced by supplies from the Netherlands, the United Kingdom and Norway. Dutch L-gas is transported on a network that is physically separate from the H-gas network. The L-gas is sold to Distrigas on a take-or-pay contract with GasTerra running to 2016. As a result, there is no competition within the gas supply regions solely supplied with L-gas. The policy implemented by the regulator to solve this issue is to extend the H-gas grid to L-gas customers – this process will take some time.

The amount of available transmission capacity is low with none available at all (current or planned) on the L-gas network. Fluxys is looking into the possibility of gradually increasing H-gas transmission capacity towards Zeebrugge from 2009/2010. This would allow much larger volumes of natural gas from the east and north to be moved through the Fluxys grid. The indicative investment programme for the period 2005-2014 represents more than USD 1.2 billion for transmission and storage infrastructure. In 2007 Fluxys will carry out a new market survey to assess the interests of the market for additional north-south transit capacity.

The Fluxys network is well interconnected with adjacent pipeline systems through 18 entry points. The domestic network will be integrated with the international pipelines to enhance Belgian security of supply and increase the liquidity of the domestic gas market.

Current investment in international gas infrastructure is targeted on three key sites in order to increase import capacity and improve the compatibility of the domestic network with that of neighbouring countries. Fluxys is working on capacity enhancement at the Zeebrugge LNG terminal, on which it is allowed to earn higher revenues. In 2006 the Interconnector Gas Pipeline built a compressor station in Zeebrugge in order to be able to reverse flows to the United Kingdom. Fluxys also is planning to expand the capacity of the VTN-RTR pipeline from 2009-2010, which includes the construction a new compressor station in Zelzate, which will enhance operational flexibility of the grid and boost supply capacity from the north. It has requested an exemption from TPA as this infrastructure would be of European interest (similar to the investments for the LNG terminal).

Storage and flexibility

The Belgian gas network is well interconnected to its neighbours, with North Sea gas from both Norway and subsequently the United Kingdom. The Netherlands' gas fields can effectively act as swing supply. This has reduced the incentive to develop seasonal gas storage, which would have performed the same role. This tendency has been enhanced by the paucity of suitable geological formations. However, the Dutch and United Kingdom swing capacity is declining fast and Belgium needs to look for alternative future flexibility.

Short-term storage is available at Zeebrugge and also by transporting LNG by truck to a storage site in Dudzele, which is used as peak-shaving facility. Hour-to-hour flexibility is also obtained by modifying the withdrawal rates from LNG tankers at Zeebrugge, in addition to the standard use of line-pack. There is one site to supply seasonal storage.

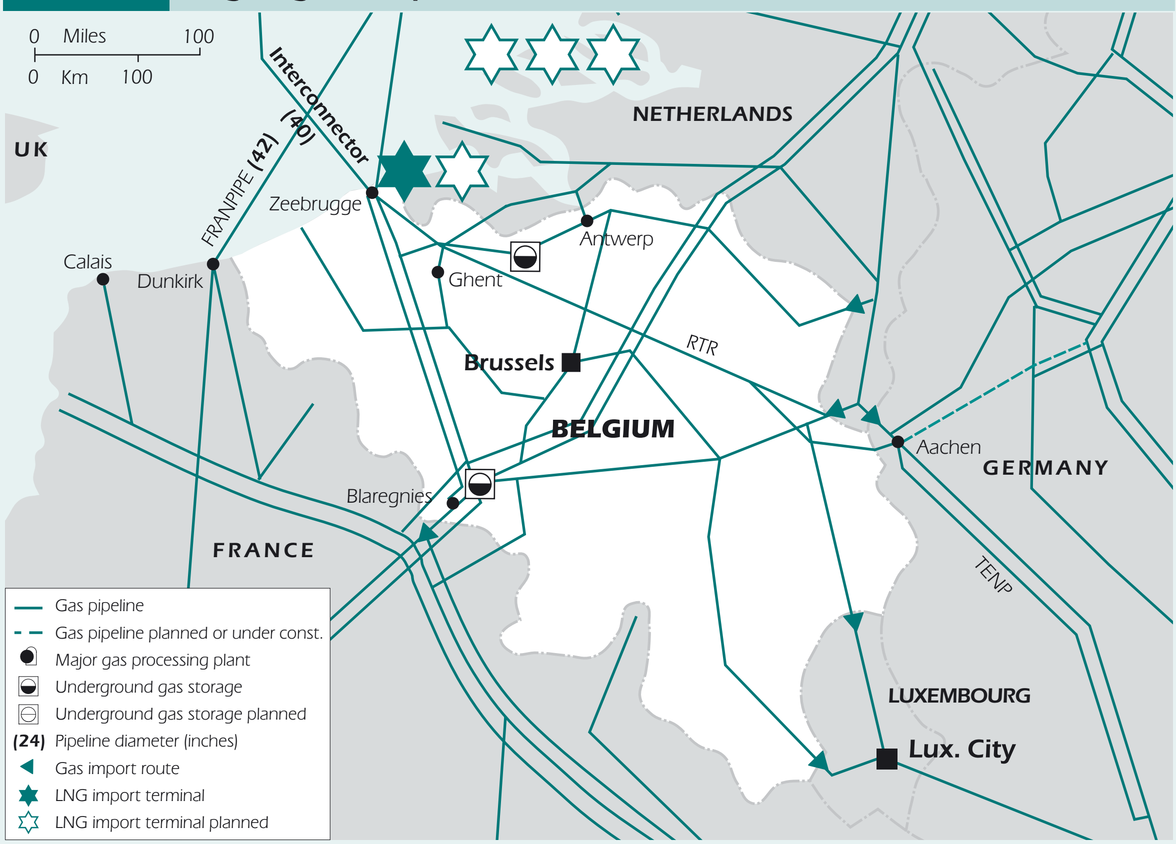
The cost of balancing services is a concern in Belgium, where balancing penalties are amongst the highest in the EU as the Belgian grid is rather small compared to adjacent grids. Some degree of imbalance is unavoidable in any gas system, as it is impossible to accurately forecast demand and supply. Flexibility is included in the base source and shippers can obtain additional flexibility with priority given to small operators. Shippers must match nominations and deliveries prior to delivery and are assessed every half hour on the day of delivery across four balancing zones. The cost of balancing in Belgium presents a substantial business risk for new entrants and is a significant barrier for entry to the market.

Gas trading

The Zeebrugge physical hub essentially acts as an arm of the United Kingdom NBP, with prices traded in United Kingdom pence per therm rather than the continental EUR/MWH. Liquidity is lower than the United Kingdom because the Belgian domestic market has been split into four balancing points (BAPs). The Belgian Northern balancing zone represents the L-gas customers supplied form the Netherlands; the other three surround the major interconnection points to the United Kingdom (West), France (South) and Germany (East).

The lack of depth can also be seen at times of stress in the market. Because Zeebrugge is a physical hub in only one balancing

Figure 64 Belgian gas transport network



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source:The Petroleum Economist Ltd..

zone, the owner of the transportation capacity to and from the physical hub controls access to the Belgian domestic market. Most of this capacity is held on long term contracts. For the first time, on 14 September 2006 the regulator required Fluxys to offer transportation services to and from the hub as from 1 January 2007. Fluxys launched the ZEE Platform Service at the end of 2006. This new service offers grid users open transfer of gas between different entry points in the Zeebrugge area via a single contract. The Zeepipe platform service simplifies physical access to the Zeebrugge hub.

Huberator s.a. (Fluxys stake 90%) operates the Zeebrugge Hub and provides services to companies active on the hub. Its facilities comprise an LNG terminal, the Zeepipe terminal and the Interconnector terminal in the Zeebrugge area. In late 2005, the company had 46 customers. The net traded volume on the hub in 2005 reached 40 bcm, which is also the throughput capacity of the Zeebrugge facilities resulting in a churn rate of 1 for the West BAP. A churn rate of 10 is considered by some a measure of a liquid hub, though other factors such as the number of market-makers and the number of counterparties are also important.

In an attempt to increase the liquidity at the hub, Huberator has launched a screen-based exchange for the Zeebrugge market in partnership with APX Gas ZEE in 2005. In the future Endex European Energy Derivatives Exchange plans to offer clearing services. Fluxys published new trading terms for shippers trading across the Zeebrugge Hub on 10 September 2006, in order to simplify hub trading.

Wholesale prices are determined through the Zeebrugge Hub, but do not impact on retail prices in Belgium as these are still linked to oil prices. Making more gas available to third parties, making access to the hub more transparent and, as a result, increasing gas volumes on the traded market is essential to increasing the liquidity at the Zeebrugge Hub, which would generate gas pricing that reflects fundamentals in the Belgian gas market. Liquidity would also be increased by collapsing the four regional balancing zones into one high-calorie gas balancing zone that includes the Zeebrugge Hub trading point and one low-calorie zone with quality conversion services. Currently, oil-indexed prices dominate within Belgium, providing no useful pricing signals about the supply and demand of gas. Furthermore, Belgium does not see pricing signals that would identify the need for new investment in capacity and other infrastructure. This puts considerable strain on the Fluxys system and compromises security of the domestic supply network.

Turkey

The role of gas in Turkey

Turkey's population has grown by more than 25% over the 15 years from 1990, to nearly 73 million in 2005. Even with slowing growth, by 2020, the population will reach nearly 90 million. Following the economic crisis of 2001, the economy has rebounded strongly, at between 6% and 8% per annum. Nonetheless, per capita GDP is less than a third of the OECD average. The investment climate has improved substantially over the last six years, stimulating a strong increase in foreign direct investment.

Energy demand per capita is low. However, total primary energy is growing rapidly; anticipated growth is 7 % over this decade, from 86.4 mtoe in 2005 to 126 mtoe in 2010 and 222 mtoe in 2020, although forecasts have tended to over-estimate already high demand growth. Gas and coal are predicted to grow rapidly, so that by 2010, their shares of the total supply will approach 30 % each (see Figure 66).

Gas has grown its share of the energy mix from just 5% in 1990 to 25% in 2006. In 2005, total gas use was 30.9 bcm, up nearly 100% on 2000 consumption, ranking just behind Spain and Korea in the ranks of IEA gas users. Gas plays an important role in the electricity sector; gas-fired power has gone from 10 TWh in 1990 to 71 TWh in 2005, the latter being 44% of power produced. The electricity sector unsurprisingly is the major driver of gas demand, accounting for nearly three-fifths of gas use.

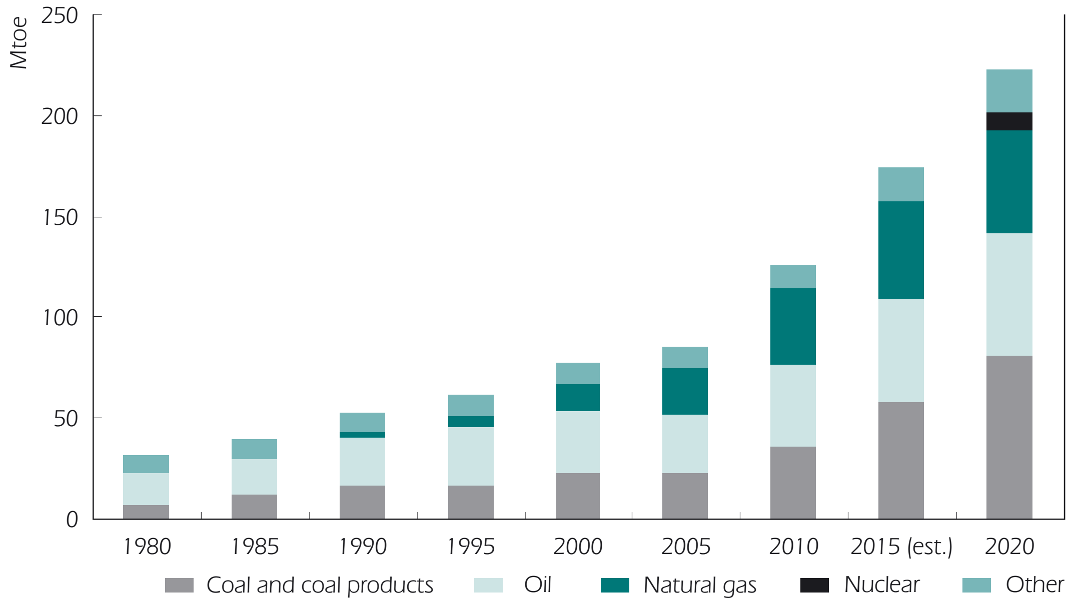
Turkey produces only 3% of its gas needs, so almost all supplies are imported, with two-thirds coming from Russia. LNG imports from Algeria and Nigeria provide one-sixth as does pipeline gas from Iran (4.3 bcm in 2005). Contract LNG supplies have been supplemented by spot purchases as in most IEA countries. Iranian pipeline imports started in 2001 and in 2003, gas arrived from Russia via the Blue-Stream pipeline under the Black Sea. The pipeline has a capacity of 16 bcm per year, but shipments are likely to rise relatively

Figure 65 Gas transport network in Turkey

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

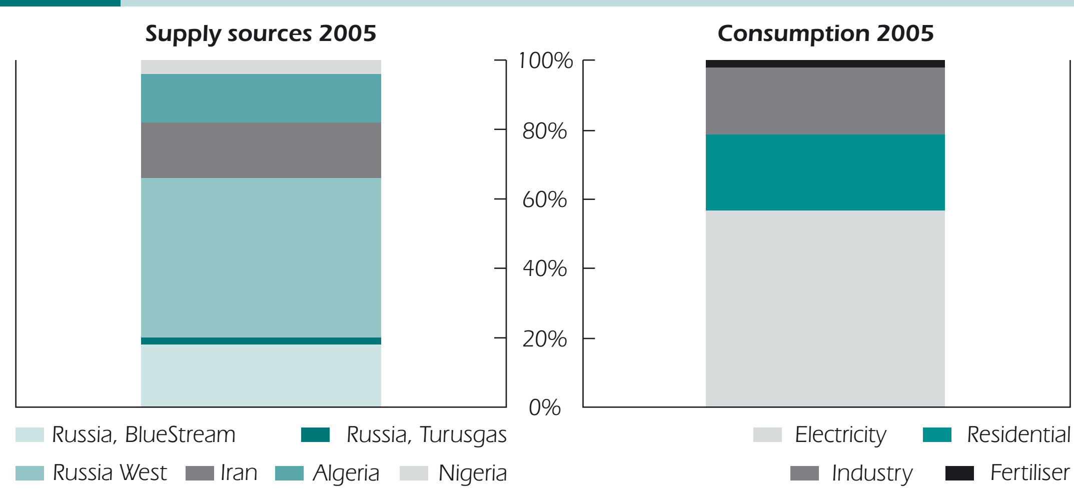
Source: The Petroleum Economist Ltd..

Figure 66 Turkish primary energy supply



Source: IEA data and Turkish government.

Figure 67 Turkish gas supply by source and demand by sector



Source: IEA data.

slowly to that level, standing at 7 bcm per year in 2006. The threat of "oversupply" is not great as there is flexibility in the Blue-Stream contracts. Meanwhile demand is growing in the power, industrial and residential sectors as gas distribution networks are expanded, especially in cities.

As noted elsewhere in this Review, in December 2006 and January 2007, Iran reduced its pipeline gas delivery to Turkey due to domestic gas supply problems, as had happened previously. The winter was exceptionally cold and many Iranian cities saw their gas supply cut off. Iran is rapidly expanding its national gas networks, which has caused many technical and operational problems in cold winters, leading to drops in gas pressure in its export pipelines.

Gas infrastructure

After completing the East-West connection to allow for the import of gas from Iran in 2001, BOTAS (the Petroleum Pipeline Corporation, a 100% state-owned company) more than doubled its grid between 2002 and 2005 giving it a total length of 7 809 km. In 2006 another 2 359 km was built, extending the grid to more than 10 000 km.

Although Turkey has rented storage capacity in Ukraine to date, the first sizeable storage in Marmara Sivrili will come on stream in 2007. This is a depleted gas field with 1.5 bcm working volume to the west of Istanbul. In addition, the tendering process has been started for a storage site which will ultimately contain 5 bcm of gas in caverns at the salt lakes 150 km SE of Ankara (Tuzgölü). Plans are also being made for a smaller 0.6 bcm storage in the South near Mersin.

Market structure and liberalisation

BOTAS is the sole importer of gas and the owner of the high pressure grid. Under the Gas law it has to give up 80% of its import activities by 2009 and is not allowed to conclude new import contracts until that situation has been achieved.

The tariffs for transportation on the high pressure grid and for distribution are set by the regulator, but those for transit will be set by the Minister, probably at least until the expected East-West transit structures have been set up.

Gas release programme

The first transfers of import contracts (12%, 4 bcm per year for 15 years) to the private sector were tendered out and awarded at the premium offered by the highest bidder. They are to be implemented by BOTAS before the end of 2007.

As in some other IEA countries implementing gas liberalisation efforts, storage is considered secondary. This means that balancing problems are surfacing. BOTAS does not offer storage while commercial storage is not available. Buyers seem to have different attitudes on the need to address this issue before deliveries start, or instead rely on improvised solutions once the scope of any problems becomes known from practice.

Distribution developments

The five older grids in the main cities are well developed. They were owned and controlled by the municipalities, but two have now been privatised leaving Istanbul, Ankara and Izmit. These grids have over 4 million connections and aggregate sales of 8 bcm per year. The Government started a privatisation process for the grids in Istanbul (IGDAS), Ankara (EGO) and Izmit (IZGAZ), but the tender has been withdrawn.

Retail distribution to the rest of the country is well underway. Concessions for 30 years are being issued by the Regulatory Body (EMRA) after a tender process. Local investors have shown particular interest in the 27 new grids currently operating. Almost USD 400 million has been invested in these latter grids while USD 650 million is planned for 2007. So far 450 000 new connections have been made with sales of 2 bcm in 2006 by the new operators. This is likely to rise to 600 000 connections and 2.5 to 3 bcm in 2007.

The competition for these grids is strong despite the fact that owners can only charge customers a connection fee (currently USD 180) in addition to the city gate price. The fixed and variable costs of distribution for a fixed period of 8 years are not therefore passed on to the consumer, resulting in very low margins. The investor and owner, typically a construction company, is obviously banking on the regional monopoly concession of 22 years following purchase as well as the income from associated services. Some smaller grids have been sold and acquired by other grid owners. The largest number of grids in the hands of one owner is eleven.

All grid operators/licence holders including the old ones are members of an active, new grid organisation Gazbir (Union of Natural Gas Distribution Companies) which is well recognized by the authorities and involved in international bodies like Eurogas and IGU.

Regulatory developments and prices

The whole Turkish grid serves as one Entry Exit zone with small differences in entry tariffs depending on the entry point, but identical exit tariffs throughout the country. Imbalances are likely and will require balancing by BOTAS. A network code has been in force since 2004, but has not been implemented as the market has only one supplier. Discussions on possible improvements are ongoing. The return on investment for BOTAS is set by the Government, based on international benchmarking. No incentive regulation is in place yet or officially planned. Storages will not be regulated under current rules.

Gas pricing, as well as transportation and distribution tariffs are regulated by EMRA. BOTAS, IGDAS and EGO make adequate returns, while new distributors have low profitability for reasons described above. The full impact of liberalised pricing will become clearer once the gas release program becomes effective and the successful bidders have to survive in an environment based on the traditional border price plus the same charges for transmission that their government-owned competitors are facing. It is unclear how prices will be affected for different classes of consumers as markets liberalise given existing price controls.

Supply developments

The Bluestream pipeline is running at only about one-third of capacity, while the first Gazprom contract, for imports from the West of Turkey via Bulgaria (6 bcm per year) will expire in 2011. Technically, the Bluestream system could accommodate these volumes at its current supply levels as well, but the potential role of Gazprom would then be reduced (given the need for other imports at the expected high levels of demand). The doubling of Blue-Stream announced in the past would help, but the timing of that expansion is unclear.

The contract with Azerbaijan (2.8 bcm for 2007 ramping up to 6.6 bcm per year) has become less certain after the cancellation in early 2007 by SOCAR of the supply contract with Gazprom (see Central Asian section). Although in the short term, it appears that current production does not allow the Azeri gas industry (SOCAR, BP Statoil, Total) to fulfil all domestic and export requirements plus the needs of Georgia as a transit country, Azeri and east of Caspian gas potential still have considerable upside in the medium to long term. Iran seems to have regular supply problems in winter, as gas flow to Turkey tends to be very low between December and March.

Exploration is at a low level; domestic production seems set to meet only a very small part of Turkey's gas needs. Therefore, in order to meet its own demand, Turkey has signed eight long-term sales and purchase contracts with six different supply sources ranging from Turkmenistan, Azerbaijan and Russia to Middle Eastern and African suppliers. In addition, Turkey wants to promote gas trade with potential suppliers and shippers.

Within this framework, to meet the increasing natural gas demand and also to diversify its gas trade portfolio, Turkey plans to develop a new LNG terminal in Ceyhan. Turkish authorities envisage that Ceyhan will become one of the major energy hubs in the Eastern Mediterranean.

Due to significant gas supply problems with Iran, Turkey imported extra LNG in winter 2006/07 (1.5 bcm) through the only receiving terminal built by a private company (in Izmir) constructed in 2002 by EGE gas, but being used for the first time now. Though the export potential of Azerbaijan requires further clarification it could be as high as 15-20 bcm by 2015. Pricing issues between the Azeri Government and BP/Statoil are still to be resolved. New developments in Turkmenistan (rich in gas resources and already a large exporter westwards) and Kazakhstan, where considerable volumes of associated gas will be produced from oil field development, mean that new volumes are likely to become available close to the Turkish market (see also Central Asian section).

Discussions are occurring about future gas supplies from northern Iraq including a potential LNG liquefaction plant in Ceyhan. Such plans may need to await an improvement in the situation in Iraq.

Turkey as a transit country

Turkey has high hopes of playing a significant transit role, bringing gas from the Caspian or the Middle East to Europe. Turkey is keen to establish new gas supply routes, to increase co-operation among neighbouring countries and to stimulate the integration of Turkish and European gas markets.

One project under construction is the Turkey-Greece Pipeline Project, a 300 km interconnector, passing under the Sea of Marmara. Interconnection to Italy is also being considered; transport volumes could reach 11 bcm, with 8 for Italy and the balance for Greece.

Box 5 Nabucco

At 3 400 km in length, Nabucco is designed to link Caspian and Iranian gas supplies with eastern Austria via Bulgaria, Romania and Hungary. The Nabucco Pipeline consortium (Vienna-based Nabucco Gas Pipeline International) consists of Austria's OMV AG, Turkey's Botas, Bulgar Gas of Bulgaria, Romania's Transgaz and Mol of Hungary (20% interest each). The first co-operation agreement for this project was signed in 2002, with a feasibility study completed in December 2004. Construction of the pipeline is planned to commence in early 2008, for first phase completion in 2011. A final investment decision is expected by end-2007. Initial throughput capacity is put at between 4.5 to 11 bcm per year with a gradual increase to between 25.5 and 31 bcm per year by 2020.

During a conference of Energy Ministers held in June 2006 in Vienna, the pipeline project member countries agreed to accelerate commercial, regulatory and legal work necessary for the implementation of the project "in the shortest possible time". Nabucco was characterized as one of Europe's most important energy projects, one that would allow the EU to diversify both its transport routes and its suppliers.

The consortium initially regarded Iran as a primary source of gas for the first stage of the project and Tehran signed a Memorandum of Understanding with OMV in January 2004 to assess what role the National Iranian Gas ExportCo (NIGEC) could play in the pipeline. However, Iran's exports to Turkey have been much lower than those stipulated in the contract and sometimes been interrupted, as noted above; currently, project sponsors have reoriented their supply priorities in favor of the Caspian, in particular Azerbaijan. Another important pre-condition for this project (and other transit projects that may arise) is clarification of the regulatory regime covering transit gas, plus plans to deal with possible congestion as domestic gas use grows. Further details on regulatory issues in IEA Europe are discussed in the sections on Investment and Regulation.

Conclusions and outlook

Acceptance by the public and by local investors of gas infrastructure is good. Turkey now has a nationwide gas grid, entry points from several directions and some emerging supply flexibility through storage sites. The result is continued high growth in spite of increasing global price levels. Liberalisation is progressing, but slower than anticipated earlier. All the institutions are nevertheless in place.

The outlook suggests a continued strong role for gas in power generation, from 71 TWh in 2005, to more than 100 TWh in 2010 and 165 TWh by 2020. Even then, this implies a lowering of the share of gas, displaced by ambitious plans to raise the share of coal and to introduce nuclear power by the end of the forecast period.

On the gas supply side, Turkey has taken steps to diversify import sources and routes, including using spot LNG

Figure 68 **Nabucco project**

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: The Petroleum Economist Ltd..

markets. In addition to existing sources (Russia and Iran), natural gas is expected to arrive from Azerbaijan in mid-2007. In the longer term, Turkmenistan or Egypt could be other alternatives. Stabilisation of the political situation in Iraq would offer great potential for gas exports due to its proximity to Turkey and vast gas resources.

EUROPEAN REGULATORY ISSUES

The following section is divided into two parts.

The first part is intended as an illustrative example of wider cross-border regulatory issues in Europe, although precise details are not applicable in all circumstances. As noted in the Investment chapter, cross-border regulation is probably the largest single factor inhibiting investment in downstream European gas infrastructure. This is a major challenge for a region which, according to the Supply and Demand section, has to deal with a major structural change in gas supply to 2015. Between 2004 and 2015, annual IEA European gas demand is expected to grow by 111 bcm – all of which is likely to be imported. The particular investment discussed in this part, the expansion of a major import line into Italy, is important for IEA countries to understand for several reasons:

- Italian domestic production is declining while gas demand and import requirements are growing, being driven by power demand growth. The required investment in infrastructure as a result of this structural shift can be seen as illustrative of the investment requirements in the wider European context.

- The current lack of consistent and stable regulatory powers or oversight for cross-border investments between European countries and the resultant uncertainty is illustrated.

- The general lack of experience in continental Europe concerning expansion of pipeline capacities on a competitive basis is highlighted.

The second part is a discussion of the internal regulation of gas markets within four selected member countries in the North West of Europe: The United Kingdom, The Netherlands, Norway and Belgium. In the context of the rapidly changing European gas market described above, this area is clearly the crossroads. These four countries account for five-sixths of European production, but only a third of demand and therefore are already a large transit area (Netherlands gas movements are twice national gas use and for Belgium transit flows are nearly four times domestic gas use). Emerging LNG import hubs, (as described earlier), will accentuate these trends, as will the advance of regulatory reform. The area is emerging as something approaching a competitive sub European market, but achievement of this potential is clearly dependent on regulatory policies.

The overview of policies present a rich tapestry of differing approaches, with some types of investment treated more favourably in some areas, relative to others. For example, low transport tariffs in the Netherlands may favour transit through that country, even if it is not necessarily the best route. Uncertainty flowing from legal challenges complicates an already fragmented regulatory picture. It seems clear that these approaches will certainly not make large scale cross border transport of gas easy, cheap or quick to achieve.

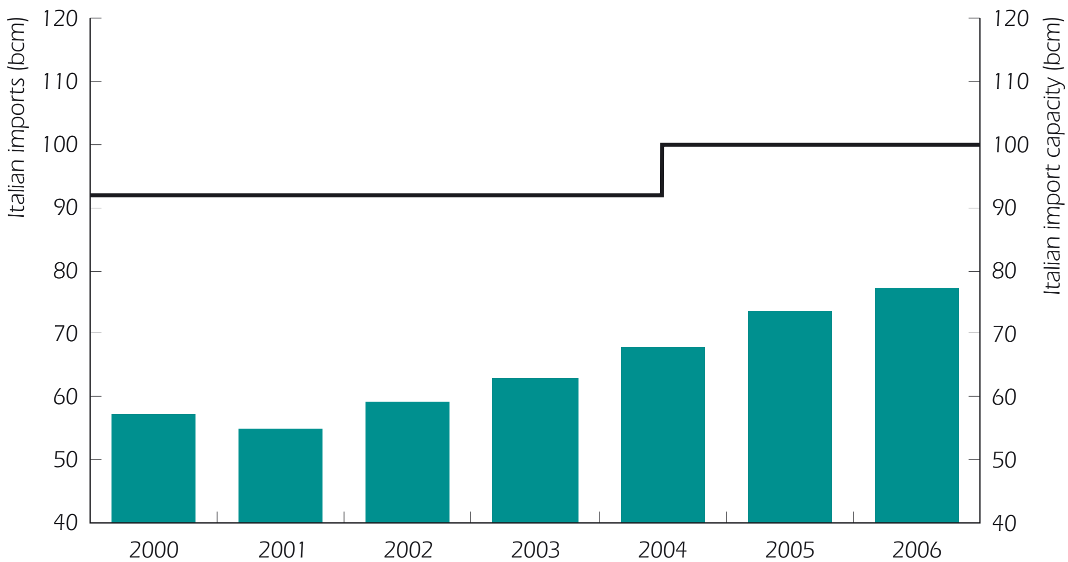
Cross-border regulatory issues in Europe: Italian example

The Italian gas market faced severe supply difficulties in winter 2005/06 forcing the Italian government to declare a "Gas

Emergency" just before Christmas 2005. As reported in the *GMR 2006*, this situation was brought about because of a severe and prolonged cold winter which increased demand for gas heating and for power generation. Less reported is the effect of the high European power market prices. High power prices gave the Italian gas-fired generators financial incentives to produce power for export – effectively therefore, Italy exported large volumes of gas in the form of power (usually for peak load). Because there is no meaningful competition within the Italian gas market and gas prices are fixed to oil, not responding to demand fundamentals, the gas price did not increase in response to gas supply tightness – an increase which would have lowered industrial and generation demand as seen in the United Kingdom in winter 2005/06. Nevertheless, the experience of a "gas emergency" has convinced the Italian government of the importance of providing information to market participants. Physical flow information is now available to the market, by pipeline, on at least a monthly basis for all entry and exit points on the Italian system.

Observation suggests that Italy's gas market can not be described as "competitive" or "liberalised". In competitive liberalised markets, capacity use is optimised based on supply and demand fundamentals. There is 100 bcm of physical entry capacity into Italy which could be used for imports, but total imports were 73.5 bcm in 2005 and 77.4 bcm in 2006 despite the gas emergency. Physical entry capacity to the Italian grid is underused because it is

Figure 69 **Under-utilisation of Italian import capacity**



Source: IEA data & GIE capacity data.

tied to long-term contracts which cannot respond quickly to unforeseen demand. A relatively mild winter in 2006-07 has masked the problem, but new capacity is only due online after 2008 (and only then in small quantities). The Italian gas market is therefore likely to remain tight unless existing capacity is made available to market players with available supply. In addition, Italy has only one operating LNG terminal, with delays slowing other terminal developments.

A major import pipeline from Austria can provide an illustrative example of some of the challenges to Italian policy makers if they are to optimise import capacity to Italy. This example is indicative of a wider problem in Europe with regards to several key aims of the internal market – to increase cross border investment, provide security of supply and to promote competition.

Import capacity investment: the TAG pipeline as a lesson for Europe?

The TAG gas pipeline is the Austrian stage of the pipeline system which links Russia, Ukraine, The Slovak Republic, Austria and Italy – and is therefore an extremely important source of gas imports for Italy. Capacity on the TAG pipeline is almost 100% booked on long-term contracts as is usual for older infrastructure in Europe, however historic capacity utilisation statistics are not published. As with many other cross-border points in Europe, the congestion on this link is "contractual" rather than physical. A precise analysis of transit flows is not possible because of the lack of data and the lack of regulatory control of a pipeline which spans two countries.

TAG is operated by a private company and its operations are not regulated because it falls into the regulatory gap between Italy and Austria. Under Austrian regulatory rules, capacity allocation, congestion management and related disclosures are matters for the transit companies. Nevertheless, on 6 December 2005 the Italian and Austrian regulators met to discuss the congestion on TAG gas transit system, which was said to pose a threat to competition development and electricity and gas supply security in southern Austria, Slovenia and Italy. They concluded that it was likely that inadequate unbundling of ENI's transportation arm was one of the principal reasons, as the dominant Italian gas company, ENI has majority control of the TAG company.

The lack of competition on this route was the subject of a settlement[21] between ENI, Gazprom and the EC, as a result of which ENI undertook to promote an increase of the capacity in TAG between 2008 and 2011 depending on certain Italian market developments.

As in many European countries, rather than hold an "open season" to determine potential shipper interest, TAG ran a long-term allocation procedure. An "open

21. In 2003 the European Commission's competition services reached a settlement with the Italian oil and gas company ENI and the Russian gas producer Gazprom regarding a number of restrictive clauses (essentially destination clauses) in their existing contracts. The settlement of the Gazprom/ENI case is very significant because of the large volumes of gas involved. ENI is one of the biggest European customers of Gazprom accounting for 20 bcm per year.

season" procedure has been successfully used to build and then later to expand the capacity of the Interconnector between the United Kingdom and Belgium and is also a standard market-based mechanism used as the basis for investment in pipeline capacity in North America (*e.g.* for the USD 3 billion Rockies Express pipeline, see North American section).

The allocation procedure used by ENI was based on many smaller capacity lots than usual in an open season procedure. According to available information, Gazprom proposed at an early stage to introduce eligibility restrictions, such as ownership of existing gas supply contracts or sufficient financial resources, in order to prevent such a fragmentation of the market. However, no such requirements were imposed. It is noteworthy that although the auction took place in Austria, neither the Austrian nor the EU regulatory authorities acted as its organisers. The bidding was organized by ENI.

Italy's Authority for Electric Energy and Gas (AEEG) and its Austrian counterpart E-Control objected to this allocation of pipeline capacity on the grounds that it breached EU directives. In particular, the authorities were opposed to the way ENI 'fragmented' the additional October 2008 transport capacity by assigning it to 149 operators from 10 countries, each with about 20 mcm per year of capacity. "ENI prefers to fragment the market" an authority spokesman noted at the time.

At the end of June 2006 TAG was finalising the contractual conditions with the winning bidders of the 21 June 2006 online auction of the second capacity release of 3.3 bcm per year. Some 34 enterprises from 9 countries took part in the auctions. Clearly, a transparent, market-based process should be used in order to determine required capacity on interconnections so vital for security of gas supply.

Observations below point clearly to the key issues facing the Italian government and regulator:

- The major incumbent supplier (ENI) owns the system and has contracted almost all transportation capacity on a long-term basis, with very small quantities left for the operational companies. This places significant risk for Italian gas users with one party who might not have the appropriate supply to meet their demand at the right time.

- Transportation capacity is only released at the discretion of the incumbent over short periods, mostly during the summer months. Capacity bookings from shippers not registered in Italy are not accepted and standard agreements for periods shorter than one year are not available. That new market participants cannot plan a business around capacity availability severely discourages potential new entrants and undermines optimisation of the existing infrastructure.

- Neither regulator from either Italy or Austria exercised competence to oversee allocation of capacity to third parties on this crucial gateway to the market. Thus new pipelines between the two countries are "unregulated" for practical purposes. Companies not subject wholly to regulation of one or other country therefore fall through the regulatory gap.

- The release or allocation of international capacity is not co-ordinated with the release of necessary entry capacity into the SNAM RETE gas system, the Italian national grid controlled by ENI.

Summary

Pipeline regulation is relatively new to many European countries, where downstream infrastructure **should** now be regarded as a natural monopoly and separated from the competitive business of gas supply. As evidenced by the Italian problems in winter 20005/06 which may well occur again in the next cold winter, there is a fundamental shift in the supply/demand balance across Italy which could be used as a model for Europe. Despite the overwhelming economic case for investment in new infrastructure, the commercial incentives to invest are blurred. In the Investment section, we noted that:

"Within Europe, but across several countries there is an even greater [investment] problem, which is that there is no harmonisation of regulatory structures within the region, nor a European regulatory body. This means that a project to build a gas pipeline between two countries might be profitable on one side of the border but not on the other. Even if it were profitable at all, such a pipeline faces formidable obstacles to be built in the current environment because of a lack of timely regulatory decisions. Pipeline projects which must cross several European countries face considerable regulatory risk and uncertainty if they are to proceed."

In the example of the TAG allocation, it is clear that the demand for capacity enhancement far outstripped the supply. However, commercial pressure did not bring about the actual investment that consumers clearly needed; it was only a result of the EC settlement discussed above that any steps were undertaken. The way that the enhancement was made however, resulted in underinvestment on behalf of the Italian (European) consumer. An "open season" process involving shippers making long-term commitments to capacity would have enabled the market, rather than the incumbent, to determine the required level of investment. It is clear that such enhancement should be subject to reasonable pre-qualification conditions, to prevent small volumes of available capacity being spread over many parties. It is also clear that regulators can learn a lot from this experience.

Internal regulation of gas markets in North West Europe

This section covers regulatory developments in four North West European countries over the last decade or so. It is organised by theme rather than by country, to allow the reader to more directly compare relevant topics across countries. The discussion provides insights into how regulation is affecting investment, through creating unnecessary uncertainty, how liberalised markets can create incentives for investment and how markets can adapt in the presence of pseudo-monopoly incumbents.

More information is available in recent IEA publications: Energy Policy Reviews of; Netherlands (2004); Belgium (2005); Norway (2005) and United Kingdom (2006).

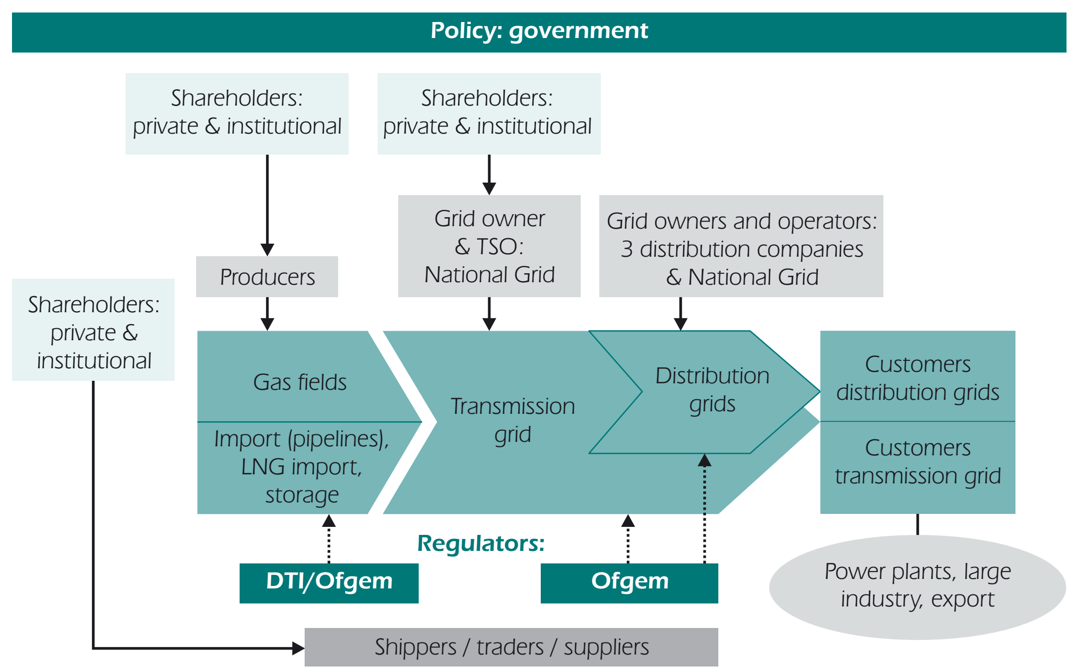
United Kingdom: industry organisation

In 1996 the Network Code was implemented providing common terms for all shippers to access the gas transportation system and thereby compete in the retail market. By 2001 the former integrated monopoly, British Gas, was privatised and had become three separate companies – a network company (Transco); a downstream gas supply company (Centrica) and an upstream production company (BG Group). The gas transmission system and four of the eight distribution networks are now owned and operated by National Grid; the other four previously owned by National Grid, were sold to three other organisations in 2005.

The Department of Trade and Industry (DTI) has the primary responsibility for energy policy goals and setting the framework which delivers them. DTI's role is to set out a fair and effective framework in which competition can flourish for the benefit of customers, the industry and suppliers and which will contribute to the achievement of the United Kingdom's environmental and social objectives. The Secretary of State for Trade and Industry is primarily responsible for the development of the United Kingdom's natural gas resources, holding authority to licence and regulate gas production and the associated off-shore gas industry.

Transmission and distribution network businesses are regulated by Ofgem, the Office of Gas and Electricity Markets. It

Figure 70 United Kingdom gas industry organisation



is directed by a board whose members are appointed by the Secretary of State. Ofgem is funded by the energy companies that are licensed to run the gas and electricity infrastructure.

The Gas Act provides for a licensing framework for gas transportation companies, interconnector operators, shippers and suppliers. To be granted a gas transport license a company must meet several obligations, such as being independent from other functions (production, supply, etc.), satisfying reasonable demand (so far as is economical), developing and maintaining an efficient system, not undertaking transactions that create a cross-subsidy with another entity and being able to meet 1 in 20 peak day demand. It also must sign up to the Network Code, to the approval of Ofgem.

Ofgem is, under the Utilities Act, responsible for the oversight of Wholesale and Retail markets and monitors the behaviour of licensees in them. Unlike most European regulators, under the Competition Act, Ofgem is also a formal competition authority for the electricity and gas sectors. This function – competition oversight – is becoming increasingly important in more liberalised markets.

Netherlands: industry organisation

The Ministry of Economic Affairs is responsible for energy policy in the Netherlands – a legacy of the important role of state participation in the development of the very large Groningen field in the north of the Netherlands. As liberalisation has taken wing, the government now focuses on diversifying gas supply, enhancing integration of the North-West European gas market and further developing the Netherlands as a gas hub by attracting gas flows and related investments. The Netherlands Competition Authority (NMa) has been given the status of an autonomous agency, fully independent from the government. Also the powers of the NMa are enhanced as it can impose fines. Notwithstanding its independent charter, the NMa is funded with the budget of the Ministry of Economic Affairs.

The directorate DTe of the NMa (NMa/DTe) is the energy regulator. For gas transmission and distribution the Gas Act introduces regulated third party access (TPA). The NMa/DTe regulates the activities of the network operators on the basis of cost-plus. Article 22 EU Directive 2003/55/EG exemption from regulated tariff structures and access conditions is possible under specific circumstances. The Ministry can relieve a network owner from the requirement to appoint a network operator. It can also exempt large, new cross-border transmission grids, LNG-installations and storage from regulation. Grid owners have to appoint a network operator, this appointment is subject to Ministerial approval.

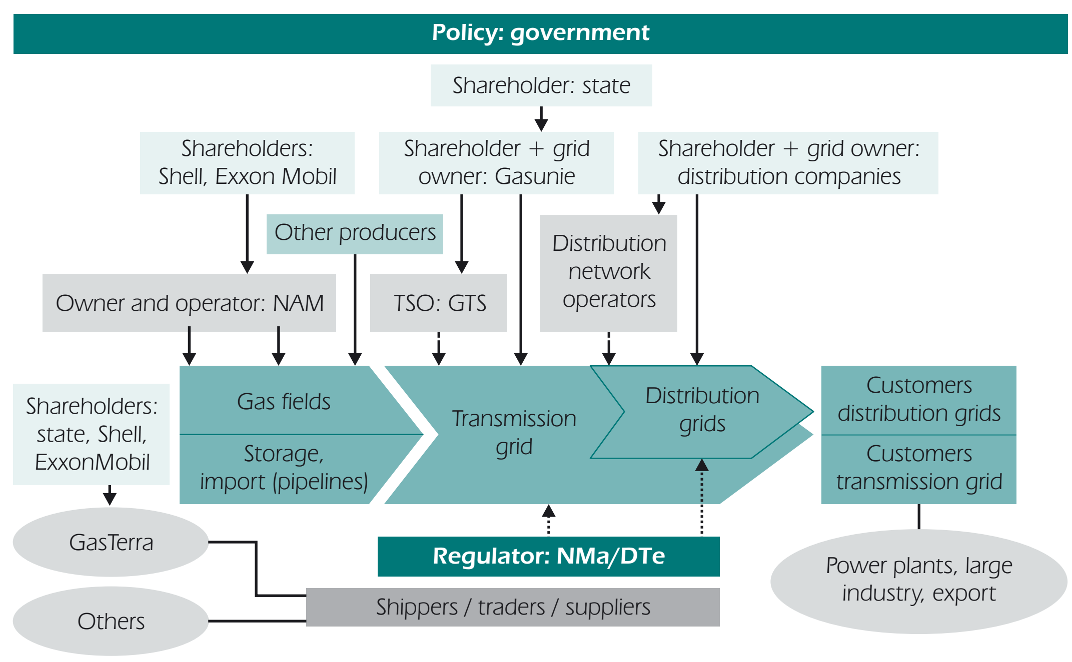
N.V. Nederlandse Gasunie (Gasunie), the Dutch gas transport company, is owned by the Ministry of Finance. Gas Transport Services (GTS), the gas transmission system operator (TSO) that operates the gas transmission grid owned by Gasunie, was founded on 2 July 2004. It is a 100% subsidiary of Gasunie, operating independently as required by law. The TSO is not allowed to carry on activities by which it would compete with other market players, except if the activities are part of its legal tasks. The trading division of the former Gasunie, GasTerra (owned by Shell, Exxon Mobil (25% each), EBN (40%) and the Ministry of Economic Affairs (10%)), has been legally and financially separated; the ownership unbundling took place on 1 July 2005.

The government is highly represented in the structure of the upstream gas market. While NAM has a 60% stake in the Maatschap Groningen, the state holds the remaining 40%. In this partnership they each have 50% of the voting rights. The Groningen field is operated by and for the benefit of the Maatschap. The partnership agreement stipulates that the Groningen gas must be marketed via GasTerra; its annual profits are capped, with the rest of the pre-tax profits going to the Maatschap.

An extra dimension of this arrangement is that the state, producers and GasTerra have agreed to prolong the life of the Groningen field by encouraging production of other, more expensive fields ('small-fields policy', codified in the Gas Act). The gas from small fields is high calorific gas and the properties vary significantly. GasTerra has the obligation to offtake the small field gas on reasonable conditions. This can be seen as the corollary of exclusive access to Groningen gas. The operators of the small fields are guaranteed a market based price for their gas. Pursuant to the Gas Act GTS has to develop connection points for the intake of small field gas.

During the last 40 years the small-fields policy has been executed to preserve the unique flexibility of the Groningen field, which is enough to cope with seasonal

Figure 71 Netherlands gas industry organisation



demand variations in the Netherlands and also in the wider European context (especially Germany). It provides swing, which enables the small gas fields to produce at rather constant rates. Nonetheless, compression capacity has been installed and will have to be expanded; the natural pressure of the Groningen field has already declined by about 50% and the production capacity is falling further. As operational costs of the Groningen field increase, local storages will become more economic (and necessary) to balance seasonal demand.

Gas revenues represent a significant part of government income. The government has protected domestic resources by controlling the depletion of the Groningen field using a production cap, maintaining the small fields policy and promoting imports. The Netherlands imported 23 bcm in 2005: 13.3 bcm from Germany, almost 7 bcm from Norway and some 2.8 bcm from Belgium. The formerly applied indirect ceiling on Groningen production has been replaced by a specific cap. However, market liberalisation now demands a policy review. The offtake guarantee gives producers reduced incentives to adapt the production profile to market demand. The Groningen gas and the small field offtake keep GasTerra in a stable market position. A specific policy is needed to encourage small fields production; a liquid market also gives a guarantee to producers that they can sell their gas.

Norway: industry organisation

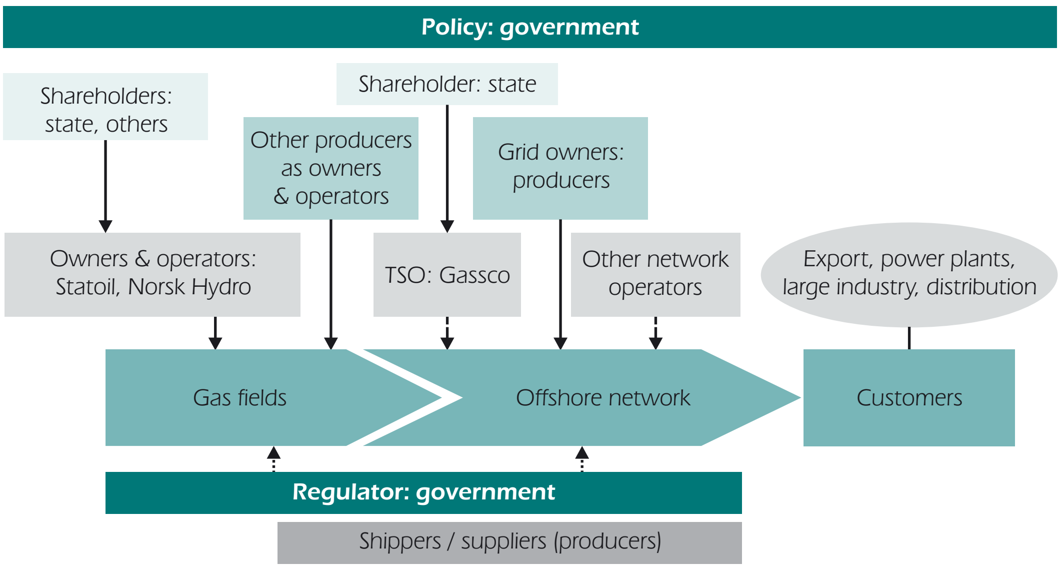
The Norwegian state owns the petroleum resources on the NCS and has the authority to manage and control exploration and production. Petroleum is the largest industry in Norway, which is the main reason for the active government involvement. The Ministry of Petroleum and Energy (MPE) is responsible for energy policy to ensure the best possible use of the country's natural resources. It is also in charge of the overall license award process. In connection with offshore operations, the MPE develops and administers treaties covering fields and transport systems which extend beyond Norway's boundaries. The Norwegian Petroleum Directorate (NPD) is the regulatory agency in this area. The NPD is an independent state administration body reporting to the MPE.

The NPD was established by the Storting (parliament), which determines the legislative framework for the energy sector. Major development projects or issues of principle must be considered and approved by the Storting. Unlike parliaments in other countries, the Storting is involved in energy-policy making to a considerable detail, reflecting the importance of energy resources to the economy and the concern about the environmental impact of energy use.

Market oversight is provided by the general competition regulator, the Competition Commission, but there is no independent regulator. Despite this, Norway has achieved a degree of balance through collective ownership of the majority of offshore pipeline networks while regulatory responsibility for the gas industry lies within the MPE.

Gassco was established by the Ministry of Petroleum and Energy on 14 May 2001 as a wholly state-owned limited company.

Figure 72 **Norway gas industry organization**



It took over the operation for all gas transport from the Norwegian continental shelf on 1 January 2002. Before that date, gas transport was provided by a number of companies. The creation of Gassco forms part of an extensive reorganisation of the Norwegian oil and gas sector since 2001.

Establishing Gassco has satisfied the requirements for ownership of gas transport operations in the European gas market specified in the European Union's gas directive, however the issue of establishing a regulator to manage Third Party Access has not been addressed. While common ownership of the system ensures that the gas is transported with maximum efficiency, there may be questions as to the independence of the pipeline system especially given the state interest in production activities on the NCS.

Belgium: industry organisation

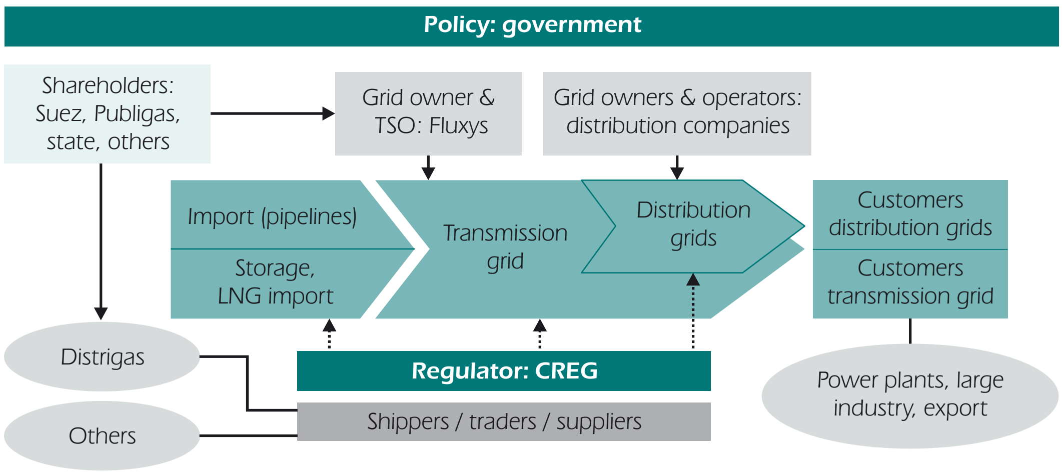
Energy policy responsibilities are split between the federal and regional governments. The federal government is responsible for issues such as security of supply, gas tariffs and network regulation for large infrastructure for storage and transmission. Energy policy aims at enhancing gas market reform and diversification. Gas transportation companies and suppliers must hold a licence from the federal Minister responsible for energy policy. The regional governments of Flanders, Wallonia and Brussels-Capital are principally responsible, among other things, for regulation of distribution and supply. The federal government and the three regional governments have created an advisory body for discussions on all energy matters transferred to the regions.

The Belgian regulator, CREG, is funded by a surcharge on customer utility bills and is therefore financially independent from the government. However, CREG commissioners are appointed by the government. The general function of CREG is to ensure that market players comply with the relevant laws and decrees. It monitors the natural gas market and is currently responsible for price setting in the "captive market", that will open to competition in July 2007. CREG has powers to approve access conditions and tariffs for transmission, distribution and connection as well as other regulated assets; a special tariff structure applies to transit, storage and LNG. It fixes tariff rates over four years (as from 2007) and must guarantee an equitable profit margin to the operators of regulated assets. For specific facilities the law provides for an exemption from the normal tariffs, allowing for potential market abuse.

The independence of the regulator is an issue in Belgium. Not all the regulators decisions are binding – CREG assesses applications for transportation and supply licences but is only charged with advising the minister rather then given statutory power. Further, the General Council (representatives of the gas market and the government) monitors the work of CREG and may also give advice to the regulator and the government. The responsibility for developing long-term indicative investment plans lies with the government in collaboration with the Federal Planning Bureau, after consulting CREG, unlike in the United Kingdom, Netherlands and Norway where it falls under the remit of the separate pipeline network operator. The indicative plan covers ten years and is revised every three years.

Owing to the federal structure of Belgium, it was the responsibility of the regions to decide on their rate of local market opening, though all must be open by July 2007 under EU rules. The regional Gas Decrees provide for regulated third party access in their own region. Distribution tariffs, proposed by the distribution grid managers, are subject to approval by the

Figure 73 **Belgium gas industry organisation**



federal regulator which is, itself, subject to approval by the government. Suppliers at the federal level must hold a supply licence from the Minister of Energy Affairs, or from the regional authority. New entrants have begun to emerge, but Suez-owned companies continue to dominate, with a 95% market share in 2005.

In the liberalised parts of the natural gas market, prices are not regulated, but the Ministry of Economic Affairs can define price ceilings. As discussed earlier, the retail prices do not follow the price of the Zeebrugge hub, so cannot be said to be determined by the gas market. For captive customers uniform gas prices are set by the federal government. CREG proposes tariffs that are subject to approval by the Ministry of Economic Affairs.

Cross-subsidies between energy products and consumer groups are not allowed. However, several subsidies remain: a fund for heating oil provides rebates to low-income heating oil customers during periods of high prices, foreclosing increased gas use in households. According to a 2001 study, 43.1% of Belgian households heated their homes with heating oil, 44% with natural gas. Oil provided nearly 40% of energy needs in the residential/commercial sector in 2004, a high figure. In addition, different taxation levels for different classes of customers function as cross-subsidies.

The national gas transmission grid is operated by Fluxys, the unbundled transportation company of former monopoly Distrigas. After the legal separation in 2001, the two companies still have the same shareholder structure. Suez, a French energy company, has a majority stake (57.25%) in both Distrigas, the dominant gas supplier and Fluxys, the gas pipeline operator. The regional utilities (as Publigaz) own 31.25% while 11.5% is currently listed on the Belgian stock exchange (Euronext Brussels). The federal government retains a preferential golden share, designed to allow it veto power if the objectives of federal energy policy may be compromised by the actions of the company. Distrigas is involved in gas import, trade and supply (including LNG) and supply of some transit capacity for a limited time from now. Suez and Publigaz have only recently agreed that Distrigas is to withdraw from transit activities – which it will sell to Fluxys (another Suez company).

United Kingdom: midstream

National Grid has two roles: as asset owner it is responsible for developing and maintaining the transmission system; as system operator it has the obligation to operate the system in an efficient and safe manner. Prices for use of the transmission system are regulated, reflecting the relatively low risk environment. However, the business of the system operator faces more uncertainty due to the complexity and exposure of its (daily) tasks. Hence Ofgem applies two types of regulation. As grid owner, National Grid earns a rate of return to encourage efficient business conduct. The rate control is based on a formula to set the level of allowed revenues. As system operator, National Grid faces seven output incentive measures from which it may gain or lose dependent on performance. Broadly the different incentive schemes can be classified into investment incentives and day-to-day operating incentives.

Price auctions of entry capacity on the transmission system were introduced by Ofgem in 1999. Of the maximum physical capacity at each entry point (the "baseline"), National Grid must offer 90% to the market through auctions. Long-term entry capacity auctions generate estimates of value which give National Grid investment signals. While National Grid is not required to build all of the incremental capacity bid for in the auctions, its price control does give incentives to invest and to maximise the technical availability of its network.

Ofgem can give interconnector operators exemption from the TPA obligations under the Gas Act for interconnectors if such access is not necessary for the operation of an economically efficient gas market and, in the case of new facilities and significant increases in capacity, where various other criteria (such as the enhancement of security of supply) are satisfied. In deciding whether to allow an exemption, Ofgem will consider participants' market share and any concerns over capacity-hoarding; it may also attach conditions to the exemption.

National Grid produces a report every year which projects expected supply and demand ten years into the future. The fifth such report, "Gas Transportation Ten Year Statement", was released in December 2006. In it, National Grid forecasts likely domestic demand, domestic production and imports from existing, under construction and planned pipelines and LNG import facilities. In the ten year statement, it projects that the country's import dependence will grow to 53% by 2010 and to 77% by 2015, notwithstanding lower demand growth from higher prices. Growth in gas import infrastructure is forecast to meet this need.

Netherlands: midstream

GTS manages the national gas transmission network including international interconnections as an entry / exit system and facilitates network access on a first come, first served basis. It also operates the LNG peak-shaving installation. The basic gas transmission activities of GTS – gas transport and ancillary services like quality conversion, as well as connection to the grid – are regulated by the NMa/DTe. Regulated TPA was introduced on 1 July 2004 by the amended Gas Act. The NMa/DTe verifies the compliance of network operators to their legal obligations, *e.g.* to have sufficient transportation capacity available. GTS has to provide the NMa/DTe with a 'quality and capacity document' every two years, in which it assesses the capacity requirements and shows how these will be met.

The Nordstream pipeline, planned for completion in 2010, is intended to transport gas from Russia (Baltic Sea) directly to Germany and perhaps onwards to the Netherlands (further details in section on Germany). European TPA rules will not apply on the grounds of increasing security of supply and on the grounds that the project is too risky otherwise.

In an open season, GTS established long-term shipper commitments for especially entry capacity in the northeast of the Netherlands and exit capacity in the southwest, anticipating westerly flows from Nordstream. To accommodate these transportation requirements GTS has proposed investments of approximately USD 1.5 billion to the NMa/DTe. GTS has requested comfort on the conditions under which investment is taken into account in the regulated asset base (RAB). The NMa/DTe has concluded in a so called "informal view", which is not binding on the NMa/DTe, that the current transport capacity on the high calorific network insufficiently safeguards future supply security, but that an investment of USD 900 million is required to safeguard supply security for Dutch consumers. This informal view does not provide the comfort asked for by GTS. The final outcome of the open season is still unclear.

Dutch tariffs are among the lowest in Europe. The NMa/DTe has obliged GTS to lower its gas transmission rates every year by 5% (nominal) from 2002 to 2006. There is a fear that "cheap tolls" will make the Netherlands the "highway" for European gas flows north to south at the expense of the domestic use of the grid. Suppliers and large consumers are responsible for the contracting of sufficient transmission capacity, but they may tend to underestimate the risks of being too late in contracting. In July 2006 the NMa/DTe obliged GTS to reserve domestic exit capacity for this reason. GTS considered this a disregard of European law and an unlawful attempt to limit the effect of artificially low tariffs and accordingly filed a lawsuit.

The NMa/DTe established a tariff structure for GTS in 2005. Its calculation of the revenue that is allowed on the RAB is based on a cost-plus methodology with a revenue cap rather than a rate of return as in the case in the United Kingdom. The NMa/DTe also defined the method to be used to calculate an efficiency rebate: a percentage by which annual allowed revenue has to decrease. This aims at reducing tariffs on existing assets but is clearly detrimental to investment in new infrastructure while GTS is not encouraged to expand services and sales.

GTS has challenged the regulations in court, arguing that tariffs should rather be based on benchmarking, taking into account the international context. On 30 November 2006 the Dutch court annulled the regulation, stating that the regulator had developed a revenue-based methodology rather than the services-based one, as stipulated by the Dutch Gas Act. The Ministry of Economic Affairs is working on new legislation to create certainty for both networks users and investors in extra transport capacity.

Belgium: midstream

CREG has set a condition that the gas network should be expanded in every case where it is necessary to meet reasonable market demand. Network development to meet inland consumption should not require long-term commitments from shippers.

The Belgian Gas Act stipulates the appointment of a single transmission system operator. Fluxys owns and operates the transmission grid on the basis of an "enhanced entry/exit system" and, since November 2002, regulated third-party access (TPA). It offers capacity and flexibility services at regulated tariffs. In 2006, 74 bcm was transported through the Belgian transmission system. Over 77% of this quantity, 57 bcm, was destined for international transit. Only 17 bcm was used for consumption and storage in Belgium.

The total transmission and transit capacity of the Belgian system is about 80 bcm per year.

Capacity is allocated by applying the first come, first served principle. Conditions and tariffs are proposed by Fluxys and have to be approved by CREG on a service-by-service basis. The system used by CREG to calculate tariffs that Fluxys is allowed to charge its customers is based on reasonable costs and a fair profit margin. Fluxys introduced a secondary market in 2006 by providing a platform to offer transportation services. Shippers are legally obliged to make available on the secondary market the firm transport capacities which they no longer require for a specific period or permanently.

CREG sets a weighted average cost of capital (WACC) on a yearly basis, representing a maximum return on Fluxys investments in regulated activities. This WACC is then multiplied by an asset value (the regulated asset base, "RAB") to arrive at the profit before tax that Fluxys is allowed to earn. The value of assets assessed to earn this WACC is based on a replacement value of the asset portfolio adjusted for investments or divestments and working capital. On the basis of 2006 the WACC was set at 7.05% and the RAB amounted to USD 1.1 billion for the transportation business. For storage and terminalling the WACC was set at 7.5%. In addition to this return on existing assets, Fluxys is allowed to pass through the costs of operational expenditure incurred while maintaining the network.

In September 2006 CREG opened a consultation on the access conditions offered by Fluxys. It also asked Fluxys to submit a proposal for new gas transit regulation. CREG wants a new entry / exit system to the Belgian network, with a single balancing zone corresponding to one set of gas quality specifications instead of the current four; it also wants to have enhanced access to transmission capacity, to the Zeebrugge Hub and to storage facilities. CREG also recommends that any (physical or contractual) separation between transit and domestic transmission should be avoided as this is irrelevant in an EU context.

In June 2005, Fluxys sent out an information request to appraise the market interest for long-term transit capacity to the United Kingdom. As part of the indicative investment program for 2006-2015, Fluxys approved the decision to increase the transmission and transit capacity on the Eynatten/Zelzate- Zeebrugge (VTN2) east-west axis which includes the construction of a compressor station in Zelzate. This compressor station will enhance operational flexibility of the grid and boost supply from the north. Work began in 2007 and the station is due to enter service for the Belgian market in mid-2008. VTN2 also includes work to lay a second pipeline on the Eynatten-Zeebrugge axis between Eynatten and Opwijk to increase supply capacity from the east. Enhanced capacity in the direction of Zeebrugge would enable liquidity growth on the Zeebrugge Hub. Alongside the Fluxys project, a parallel initiative has been taken in the Netherlands to attract more gas flows from the east and north.

Currently capacity on the VTN/RTR pipelines, linking the United Kingdom with the Netherlands and Germany, is all contracted by Distrigas (Suez) on a long-term basis, meaning that it controls the bridge between the largest European gas markets and their closest suppliers. Segeo s.a. (Fluxys stake 75%, Gaz de France 25%) owns the gas transmission infrastructure between Gravenvoeren and Blaregnies. These pipelines are referred to as "transit" pipelines because of the original function of transiting gas across Belgium and there were arguments that this exempted the pipelines from the EU TPA rules applicable to domestic networks. The European Commission does not recognise transit as being separate from transmission within the EU. Pursuant to EU regulation both of these activities are transmission within Europe and therefore subject to the same regulated TPA principles.

By marketing transit capacity, Distrigas acts de facto as transmission system operator. On 14 September 2006, the regulator decided that this was unlawful. Just before the decision of CREG, on 8 September, Suez and Publigas had announced their intent to propose a transfer of Distrigas natural gas transit business to Fluxys. CREG ruled that the unlawful situation must be resolved by 31 December 2006. The transit capacity must be passed to Fluxys; the access rules would be the same as those applying to transmission as from 1 January 2007. The same had been decided for access capacity to and from the Zeebrugge Hub (regarding the Zeepipe terminal and the Interconnector terminal). On 21 December 2006 Fluxys announced that Distrigas had commissioned Fluxys to handle, in the name and on behalf of Distrigas, the management and marketing of its transit capacities in Belgium as of 1 January 2007.

Norway: transmission pipelines

The MPE actively promotes measures to increase the number and diversify the types of companies active on the NCS. On 1 January 2007 the regulations relating to area fees changed. The main rule of the new provisions is that no fee will be paid for areas with ongoing exploration and production, while areas without activity will pay a higher fee than before. The purpose is to encourage licensees to speed up exploration in licences which are on hold, or to cede them to the state in order to give other companies a chance.

Gassco administers the regulated third party access (TPA) regime which applies to gas pipelines on and from the NCS and related installations. It is responsible for allocating capacity; the production companies' access to capacity in the system is based on their needs for gas transport. In order to secure good resource management, booked transport rights can be transferred on the secondary market between shippers. As the system is a natural monopoly, gas transport tariffs are governed by special regulations issued by the MPE. The cost-based transportation tariffs are subject to MPE approval. A maximum rate of return in new pipelines is generally specified. The regulations ensure that the economic returns are earned from producing fields and not from the transportation system. Tariffs are based on an entry/exit methodology. The Gassled system is divided into five entry/exit areas, depending on the gas quality or the processing terminal.

Gassco is responsible for the maintenance and the further development of the upstream network. It makes independent assessments and recommendations for infrastructure development. Gassco presents investment proposals based on an overall assessment of development needs and resource management. Getting these approved will depend on the willingness to invest by owner companies and resource owners. Gassco develops the annual transport plan, an annual rolling 10-year transport plan based on information provided by the respective stakeholders.

United Kingdom: storage

Import facilities and storage capability must be sufficient to meet the winter peak. The maximum demand seen in the winter of 2005/06 was 411 mcm per day. As a significant producer of gas, much of this flexibility used to be provided by increasing or decreasing offshore production as demand required. As the flexibility from domestic fields is now insufficient to meet peak winter demands, seasonal storage units will indeed play a crucial role. Existing storage peak withdrawal capacity amounts to about 120 mcm per day. The recent large discrepancies between winter and summer prices (*e.g.* spot and futures prices in Summer 2006) provide a strong market incentive for more storage plants to be built and a number of private companies have made plans to do so. However, these plans have been hampered to a great extent by local opposition and a general failure to gain planning consents – especially offshore, where there are many responsible agencies.

A major factor deterring storage investment is that, if all proposed import and storage projects went ahead, peak supply capacity would be more than twice peak demand by 2010. In mid-2006 National Grid identified eleven gas storage projects in some stage of construction or development. They are all planned to come on-line by 2010 and would add 5.7 bcm to the existing storage capacity of 4 bcm. In May 2006, the Secretary of State issued a statement addressing the urgency of new infrastructure with specific focus on storage facilities. He announced three measures: establishment of legislation to allow innovative projects (*e.g.* gas storage in offshore salt caverns and LNG projects with offshore unloading) to go ahead, a review of onshore consents regimes and improvement of public understanding of the need for new infrastructure. Storage projects are also deterred by the difficulties in converting production licenses to storage licenses for offshore fields, an issue being addressed by the government.

Belgium: storage

Belgian law stipulates that the seasonal capacity is reserved for shippers supplying the domestic market. Fluxys stores gas in an underground storage in Loenhout. It is used by three parties. CREG has recommended that the storage capacity at Loenhout be increased. In 2005, Fluxys decided to carry out a gradual enhancement by 2011-2012. In June 2006 Fluxys and Gazexport, a subsidiary of Gazprom, agreed to jointly explore the underground gas storage possibilities in Poederlee. Fluxys also has agreed to co-operate with VITO to explore other potential storage sites in Belgium and in neighbouring countries.

United Kingdom: LNG

LNG import facilities are subject to a regulated TPA regime, meaning that non-discriminatory terms of access must be published and pricing methodologies must be approved in advance by Ofgem. The first operating LNG import terminal (at the Isle of Grain) has been exempted from TPA requirements. Other LNG projects have also applied for exemptions. While this at first appears contradictory to United Kingdom open market philosophy, the government seems to have taken the approach that the more competitors in the market the better.

It seems logical that some facilities are exempted from EU TPA regulations designed to increase competition, on the grounds that other forces are providing the same outcome. The third-party-access exemptions will result in the following market parties obtaining LNG regasification capacity in the United Kingdom (many of which are new to the wholesale market); Sonatrach, Centrica, Gaz de France, Excelerate, Petroplus, BG, Petronas, Qatar Petroleum, ExxonMobil and Total (see LNG section for further details).

This should be contrasted with the situation in some other European countries where a dominant supplier in an uncompetitive market might wish to build an LNG terminal. In this case it is more logical that TPA rules apply and the supplier is forced to make a proportion of the capacity available to new entrants, or that open season procedures apply.

Belgium: LNG

In the transitional regime, Fluxys has been appointed as transport/transit and storage operator and Fluxys LNG for LNG-terminalling. In 2007, the procedure will be launched to appoint a single transmission system operator on a definitive basis for a 20 year period. CREG sets a weighted average cost of capital (WACC) on a yearly basis, representing a maximum return on Fluxys investments in regulated activities. For storage and terminalling the WACC was set at 7.5%.

From 1 April 2007, a new multi-shipper environment was created at the LNG terminal. In 2007 an open season will be launched to assess the interest of the market in additional terminal capacity as the pre-feasibility study is positive.

Netherlands: LNG

The Ministry and the NMa intend to allocate initial capacity to LNG terminals through an "open-season process". There are two proposals: The LNG company can choose to create extra capacity through a larger LNG terminal, or the available capacity can be shared on a pro rata basis by the market parties. Long term-contracts can be exempted for the duration of the period up to the breakeven point ("investment horizon"), which the NMa assumes to be approximately 15 years.

To prevent the hoarding of capacity, unused capacity should be offered to third parties through a secondary market mechanism. The time that a certain slot needs to be released on the secondary market can be neither too far from, nor too close to, the time of use, because third parties need time to buy supplies and arrange shipping. A booking period of two months is considered to be a reasonable time by the NMa and the Ministry. Therefore, the owner of the capacity should confirm the contracted capacity two months before the date of use. The NMa and the Ministry intend to require the application of a transparent principle by which the capacity would be offered on a secondary market if not used on the primary market.

United Kingdom: recent developments

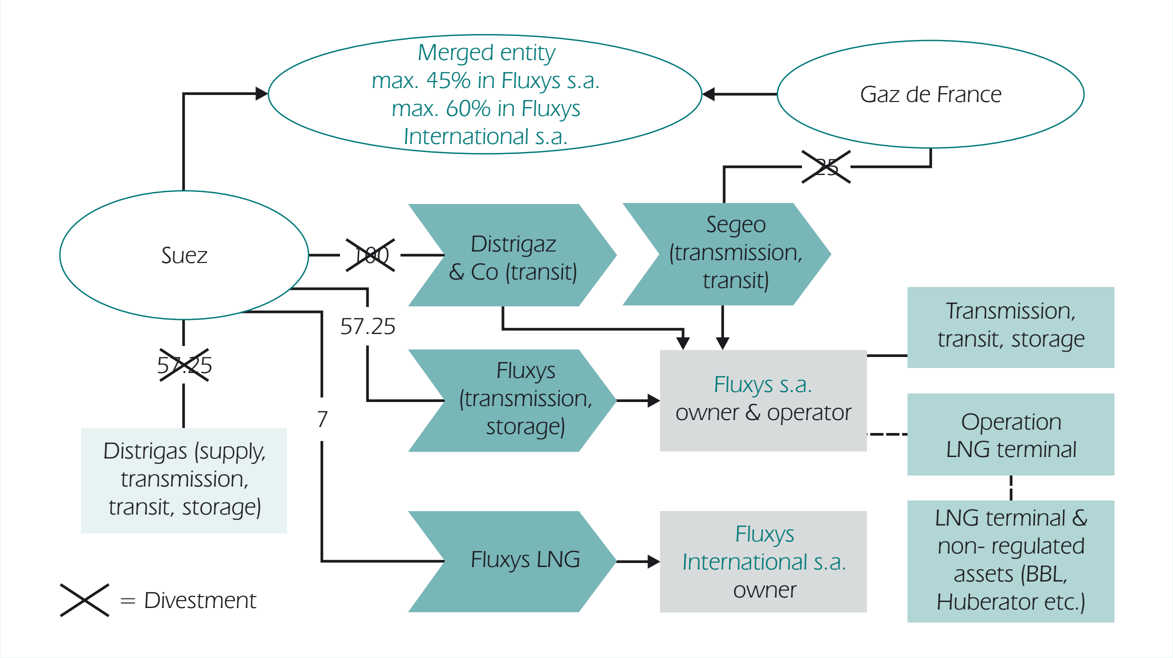
On 16 October 2006 the DTI started a consultation process on energy, which will feed into a white paper. Part of this consultation process was to ask gas market players whether existing security of supply measures in the gas sector were sufficient. In the document the Secretary of State declares that the government is currently working on strengthening the present framework, *e.g.* by looking to improve the planning process for investments in new gas infrastructure and to clarify the rules for offshore gas storage and certain LNG installations; by considering possible revisions to the gas sector emergency user arrangements; and by providing more information to market participants to help them in their consumption and investment decisions. The government has not changed its view that the costs and the risk of unintended consequences from creating a strategic gas reserve unilaterally, outweigh the potential benefits.

Government policy strives to maximise economic production from domestic reserves. The addition of two new types of licence has been central to maintaining interest and investment. These are the "promote" licence, at a tenth of the cost of a traditional licence for the first two years, to attract new smaller investors and the "frontier" licence, to ensure the maximum opportunity for appraisal of prospects west of Shetland. This new type of licence allows companies to take larger areas in the first instance. It offers six years in which to complete the exploration-phase work programme, two years longer than the more traditional licence. Environmental assessments have been carried out for a large proportion of the United Kingdom territory to make available as much acreage as possible for exploration and development. Industry has agreed a code of practice to help ensure that third party access to infrastructure can be achieved on fair and reasonable terms and to promote non-blocking commercial behaviours on the UKCS. Reaction to these changes has been positive: in 2005 the highest number of licences was awarded in the United Kingdom's North Sea history. However, there is currently concern about the low overall availability of drilling rigs needed to capitalise on this success.

Norway: recent developments

The government is actively trying to derive the maximum long-term value from the resources on the NCS, which requires that all profitable petroleum resources on the NCS are produced and that exploration and production is undertaken in extreme climatic conditions and in deeper waters. According to government estimates, this

Figure 74 Proposed organisational remedies for the merger of Suez & Gaz de France



is expected to result in gas production for up to 100 years. Total discovered and undiscovered gas resources on the NCS are approximately 6 000 bcm, while 1 100 bcm have been recovered. Gas exports are expected to reach 94 bcm in 2007, with plateau production of 120 bcm expected by 2010.

Belgium: recent developments

In November 2006 the European Commission approved the proposed merger of Gaz de France and Suez, subject to conditions. Suez has to completely divest Distrigas. Fluxys and Fluxys LNG have to be reorganised in two new companies, Fluxys s.a. and Fluxys International s.a. The merged entity cannot retain more than 60% in Fluxys International s.a., which will own the LNG terminal and the unregulated assets and 45% in Fluxys s.a., which will own and operate all transmission, transit and storage in Belgium and which will also operate the LNG terminal. To this end, Gaz de France will transfer to it its 25% holding in Segeo (which owns a gas pipeline in Belgium linking the Dutch and French borders) and Suez will transfer to it Distrigaz & Co (which markets transit capacity on the Norwegian (Troll) and German (RTR) routes).

However, the plan to merge still faces other obstacles. The French Constitutional Council has ruled that the merger cannot take effect before full market opening on 1 July 2007.

ANNEX A: EXISTING GAS SECURITY MEASURES IN IEA COUNTRIES/REGIONS

This section provides an overview of measures directed at safeguarding security of gas supply in selected countries and in the EU. The range of measures reflects the differing gas market circumstances, including availability of suitable geological storage.

France

France imports 97% of its gas supply. The share of natural gas in the country's total primary energy supply (TPES) is 14.9%, significantly lower than the IEA European average of 24.3% or the OECD average of 21.9% in 2005.

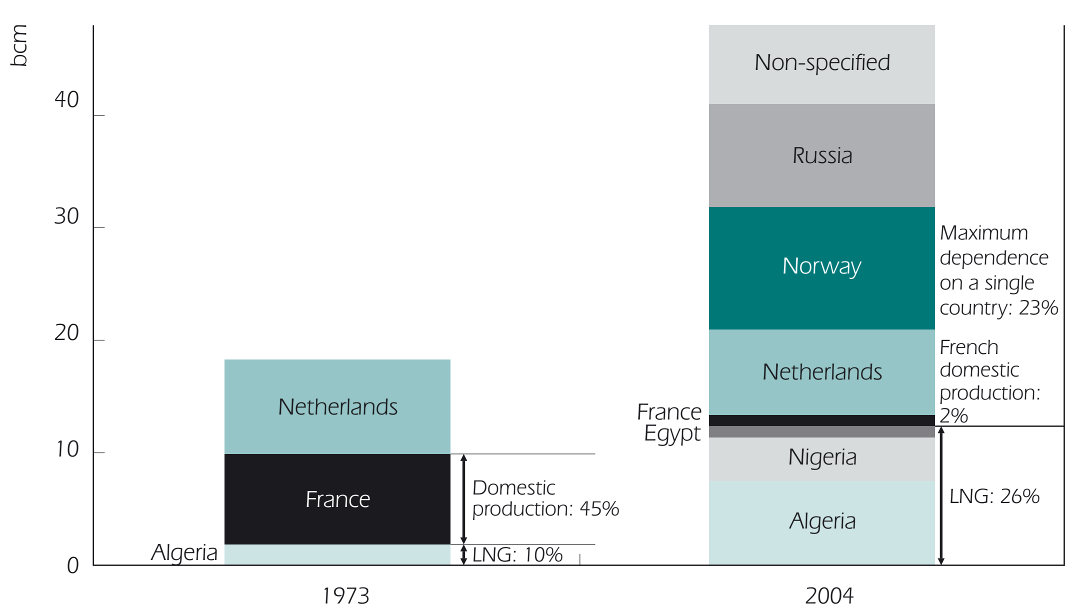
It has well diversified supply, an emphasis on long-term contracts and relatively ample underground storage capacity.

One of the notable features in the country's gas consumption is the virtual absence of gas use in power generation (less than 4% of power supplied in 2005) because of the dominance of nuclear power generation, although some companies have plans to develop combined-cycle gas turbine power plants. Heating demand is a big component of gas demand and represents almost 40% of sales in an average year, which leads to high seasonal demand fluctuations.

The priority of the country's energy policy is to ensure uninterrupted supply for customers with public service obligations (administrations, small commercial and households) which represent more than half of the country's final gas consumption.

Long-term security of supply of gas in France is based on: diversification of supply

Figure 75 **France's gas sources**

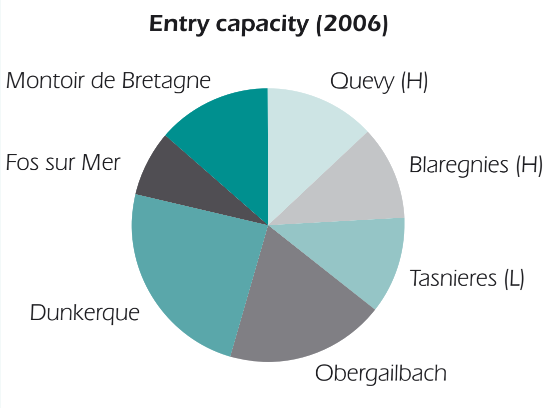


Source: *Natural Gas Information 2006*, IEA, Ministère de l'Économie, des Finances et de l'Industrie.

sources and transit routes; emphasis on long-term gas supply (85% of the total); availability of infrastructure (transmission network and storage); and knowledge of energy consumption. In fact the country has one of the most diversified gas supply portfolios in the world.

The country's domestic gas production, which represented 45% of the supply in 1973, is approaching its end.

Figure 76 France's gas entry points



Source: Ministère de l'Économie, des Finances et de l'Industrie.

France also has two export points on the Swiss and Spanish borders, Oltingue and Larrau (the Lacal pipeline) respectively. In addition, the new Euskadour gas pipe, which entered into service in the first quarter 2006 from Spain's Basque region to the southwest of France, has a transportation capacity of 0.5 bcm per year. The 28 km pipe also has reverse capability.

Another strong point of the country's gas supply structure is the amount of underground storage. Twelve aquifer and three salt-cavern underground storage facilities in total have 11.7 bcm of working capacity, which, when full at the start of winter is about 25% of the country's annual consumption. Storage facilities in France have a withdrawal capability of 200 mcm per day.

Inventories are built up in summer months from April to October and withdrawn in winter months from November to March. In addition to seasonal balancing, storage also plays an important role in regulating daily and weekly changing sales patterns, as well as optimising operations of the transmission network. Storage of this size is also capable of dealing with potential supply interruptions.

Given that no new storage capacity has entered service for nearly a decade and a half, while consumption has risen by 60%, a number of new storage facilities are under consideration. In addition, some potential sites are being evaluated in salt layers, notably in the Alsace region. Salt caverns are generally expected to play an increasingly important role, because of higher deliverability that can cope with sharper daily demand fluctuations. Aquifers especially in the southwest are also being investigated to increase longer-term storage capacity.

In order to ensure that companies use all the working capacity in the facilities, the French government in summer 2006 issued a decree to oblige gas distribution companies to have more than 85% of their allocated capacity filled by the beginning of November (based on the August 2004 Energy Act).

Table 34 Existing underground gas storage in France

	Type	Working capacity (mcm)	Depth (m)	Start	Operator
Beynes profond	Aquifer	400	740	1975	GdF
Beynes supérieur	Aquifer	210	400	1956	GdF
Céré-la-Ronde	Aquifer	390	910	1993	GdF
Cerville-Velaine	Aquifer	650	470	1970	GdF
Chémery	Aquifer	3,780	1085	1968	GdF
Etrez	Salt Cavern	450	1400	1979	GdF
Germigny-sous-Colombs	Aquifer	760	850	1982	GdF
Gournay-sur-Aronde	Aquifer	900	720	1976	GdF
Izaute	Aquifer	1,290	510	1981	Total
Lussagnet	Aquifer	1,100	600	1957	Total
Manosque	Salt Cavern	210	910	1993	GdF
Saint-Clair-sur-Epte	Aquifer	380	740	1979	GdF
Saint-Illiers	Aquifer	590	470	1965	GdF
Soings-en-Sologne	Aquifer	220	1140	1981	GdF
Tersanne	Salt Cavern	200	1400	1970	GdF
Total		**11,530**			

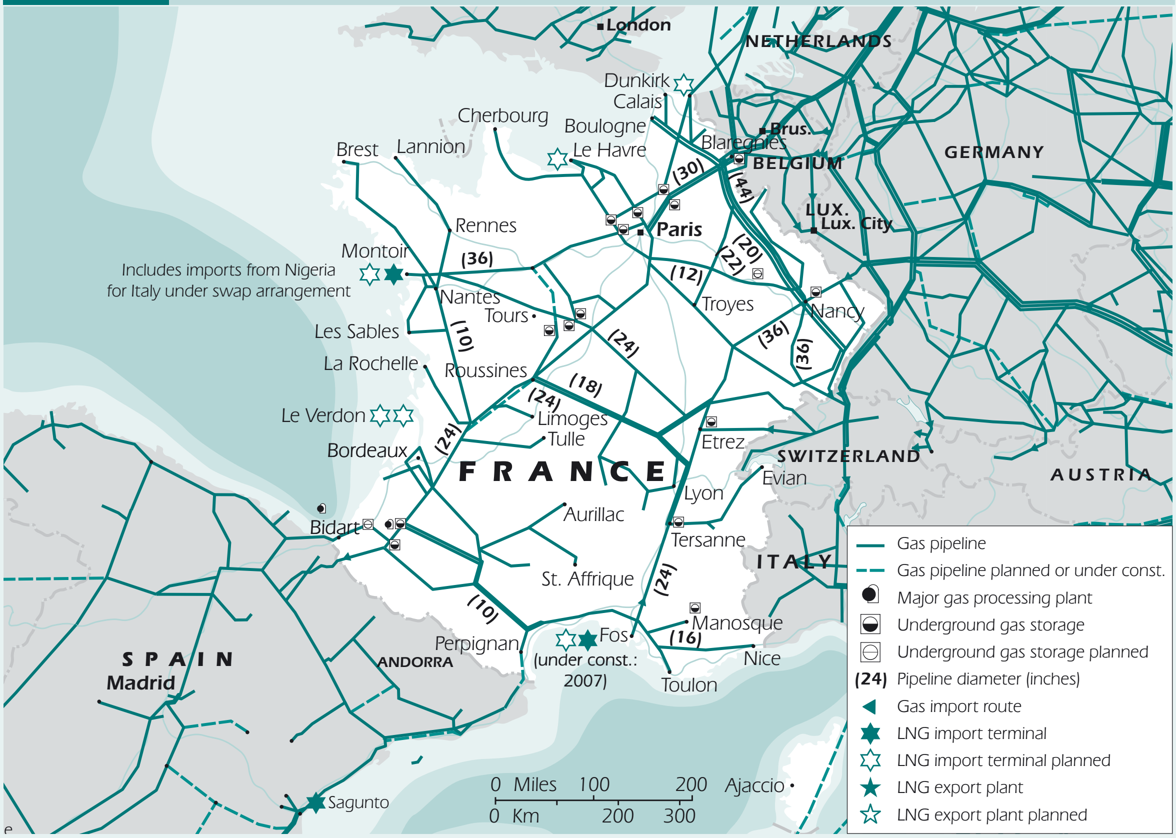
Source: *Natural Gas Information 2006*, IEA, Cedigaz: Underground Gas Storage in the World, Armelle Lecarpentier, June 2006.

Table 35 Major new and expansion storage projects in France

Project	Region	Type	Capacity
Pecorade	Southwest	Depleted oil field	n.a.
Lussagnet expansion	Southwest	Aquifer	2.4 —> 3.5 bcm
Hauterives	Southeast	Salt cavern	n.a.
Trois-Fontaines	East	Depleted gas field	working capacity 80 mcm
Etrez expansion	East	Salt cavern	n.a.

Source: *Natural Gas Information 2006*, IEA; Cedigaz: Underground Gas Storage in the World, Armelle Lecarpentier, June 2006.

Figure 77 **France's transportation and storage system**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Ministère de l'Économie, des Finances et de l'Industrie and The Petroleum Economist Ltd..

> *French decree*
>
> Au 1er novembre de chaque année, les volumes de gaz stockés par un fournisseur ne peuvent être inférieurs à 85 % des droits de stockage en volume utile, tels que définis à l'article 5 du présent décret, de ses clients domestiques, y compris des ménages résidant dans un immeuble d'habitation chauffé collectivement, et de ses autres clients assurant des missions d'intérêt général. (Article 13, Décret n° 2006-1034 du 21 août 2006 relatif à l'accès aux stockages souterrains de gaz naturel)

In the latter half of 2006, France saw more LNG terminal plans, encouraged by some indications that the country's gas sector was opening up for competition. They included three new entrants into the country's gas business. France could have as many as seven terminals totalling at least 45 bcm per year by 2011-12.

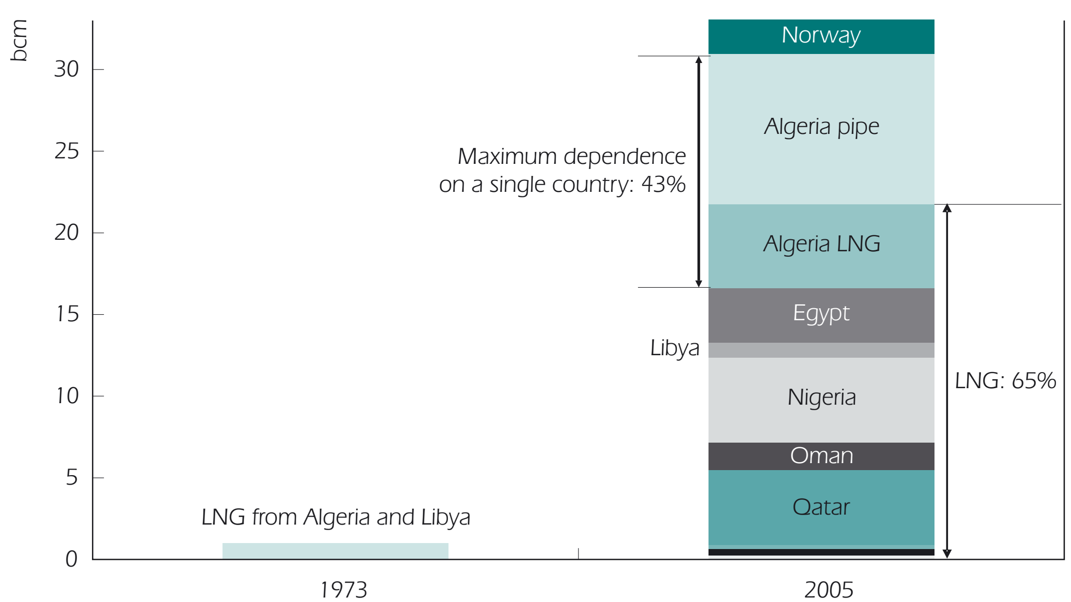
Spain

Spain's natural gas market developed later than other western European countries because of low levels of domestic production and its geographic location far from major European gas fields. The country's gas infrastructure has been developed mainly since the 1990s, when energy diversification and raising natural gas' share were given prominence in the country's energy policy agenda. The share of natural gas in total primary energy supply has grown from 5% in 1990 to more than 25% in 2004.

As the domestic production from Marismas fields has been almost depleted, the country is virtually entirely dependent on imports for natural gas supply. New exporters have gained footholds in the market very rapidly since 1990: Norway in 1995, Qatar in 1997, Trinidad and Nigeria in 1999, Oman in 2000 and Egypt in 2005, in addition to traditional exporters Algeria and Libya. Therefore the current supply portfolio is quite well diversified in terms of pipeline vs. LNG supply sources.

Over the past three years, gas demand in the country has increased by 13-18% annually, reaching 32 bcm in 2005, due to strong economic growth and increasing gas use in power generation. Development of combined-cycle power plants, which entered into operation only in 2002, is expected to drive growth of gas use in the future. The composition of gas use in 2005 was: 55% for industrial, 30% for power generation and 15% for small commercial and residential sectors. In 2006, it was 52% for industrial, 34% for power

Figure 78 Spain's gas sources



Source: *Natural Gas Information 2006*, IEA.

generation and 13% for small commercial and residential sectors. The consumption of combined-cycle power plants grew by 45% in 2005.

Due to generally milder weather and consequential smaller residential gas use, seasonal fluctuations in gas demand are rather small compared to other European countries. However, the strong rise in gas demand for power generation has not been evenly spread throughout the year. Especially in 2005 and 2006, the total daily demand for natural gas broke records on several occasions during winter months.

Table 36 LNG terminals in Spain and expansion plans

Terminal	Tank	LNG storage capacity in liquid (m^3)	Equivalent days of national gas consumption	Start	Operator
Existing					
Barcelona	No. 1-4	240 000		1969	Enagas
	No. 5	150 000		2005	Enagas
Huelva	No. 1-3	310 000		1988	Enagas
Cartagena	No. 1-2	157 000		1989	Enagas
	No. 3	130 000		2005	Enagas
Bilbao	No. 1-2	300 000		2003	Bahia de Bizcahia*
Subtotal		**1 287 000**	**8.6**	**as of 2005**	
Sagunto	No. 1-2	300 000		2006	Saggas**
Barcelona	No. 6	150 000		2006	Enagas
Huelva	No. 4	150 000		2006	Enagas
Subtotal		**600 000**	**4.0**	**2006**	
(2005-06 addition)		880 000	5.9		
Total		**1 887 000**	**12.6**	**as of 2006**	
Future plans					
Mugardos (El Ferrol)	No. 1-2	300 000		2007	Reganosa Group***
Cartagena	No. 4-5	300 000		2008-2010	Enagas
Bilbao	No. 3-4	300 000		2008-2010	Bahia de Bizcahia
Barcelona	No. 7-8	300 000		2009-2010	Enagas
Huelva	No. 5	150 000		2009	Enagas
Sagunto	No. 3-4	300 000		2009-2011	Saggas
El Musel	No. 1-2	300 000		2010	Enagas

*BP, Repsol, Iberdorola, EVE.
**Endesa, Iberdrola and Union Fenosa along with the Oman government.
*** Endesa, Union Fenosa Gas, Galicia's Tojeiro group, Algeria's Sonatrach, the Galician government, Caixa Galicia, Banco Pastor and Caixanova.
Note: The list does not include terminal plans in the Canary Islands.
Source: *Natural Gas Information 2006*, IEA, company information.

Figure 79 **Spain's transportation and storage infrastructure**

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: The Petroleum Economist Ltd..

The total length of Spanish gas pipelines was 58 870 km at the end of 2006, including around 41 000 km for distribution. The network covers most of the country and it has five international connections via pipelines: Larrau, receiv-ing gas from Norway via France; Tarifa receiving gas from Algeria via the Pedro Duran Farell pipeline; Tuy and Badajoz interconnecting with Portugal; and the two-way Euskadour gas pipeline between France and Spain, which entered into service in the first quarter 2006. The two connections with France are currently capable of transporting 3 bcm per year from France to Spain.

Furthermore, the construction of a new deepwater import pipeline, Medgaz, directly linking Beni Saf on the Algerian coast to Almeria on the Spanish coast, is underway. Completion is expected in early 2009. Most of the initial capacity of 8 bcm per year should be absorbed by the Spanish market.

In addition, the country has five LNG receiving terminals in operation: Barcelona, Huelva and Cartagena by Enagas, Bilbao by Bahia de Bizcahia Gas, SL (owned by BP, Repsol, Iberdrola and EVE) and Sagunto by Saggas (owned by Endesa, Iberdrola and Union Fenosa along with the Oman government). Another one is being constructed at Murgados (El Ferrol), due to be completed in 2007. Enagas is also expanding its existing three terminals and has a plan to build and manage a new import terminal in the port of El Musel, the Bay of Biscay, in northern Spain.

Spain currently has two underground storage facilities in depleted gas fields and plans to install some additional storage capacities, according to the Revisión 2005 – 2011 de la Planificación de los Sectores de Electricidad y Gas 2002 – 2011 (Updated Mandatory Planning for Gas and Electricity Markets for 2005 - 2011) approved by the government. Those projects, if realised, would boost total working capacity to 7 bcm in 2011. Combined with LNG terminal storage, the country could have 70-day national consumption equivalent working storage capacity in 2011, assuming a 6% annual growth in gas demand in the period.

In the winter of 2005 - 2006, due to severe cold weather combined with low hydro output and tight global LNG market conditions, the Ministry of Industry, Tourism & Trade mandated that 2 LNG cargoes be stationed off the coast at all times as insurance against shortages.

In 2006, the country saw lower gas demand growth (gross inland deliveries up only 2.3% in 2006, compared with +18% in 2005, and five years of strong double digit growth), especially in the power sector, as hydro power conditions were improved. Land-based gas storage has also been augmented (Marismas Phase 1).

LNG storage capacity was increased by 600 000 m³, which is equivalent to 4 days

Table 37 Underground gas storage in Spain

		Working capacity (mcm)	Equivalent days of national gas consumption	Deliverability (mcm per day)
Existing				
Serrablo	depleted field	820		6.8
Gaviota	depleted field	1 446		5.7
Subtotal		**2 266**	**25.6**	**12.5**
Planned for 2005-11				
Marismas (Phase 1)	depleted field	300		1.6
Marismas (Phase 2)	depleted field	600		4.4
Poseidon	depleted field	250		1.5
Gaviota expansion	depleted field	1 558		14.2
Yela	Aquifer	1 050		15.0
Castor (Amposta)	depleted field	1 300		25.0
Reus	Aquifer	n.a.		n.a.
Total in 2011		**7 324**	**82.8**	**assuming current demand**
			58.3	**assuming 6% growth in demand**

Source: *Natural Gas Information 2006*, IEA, Cedigaz: Underground Gas Storage in the World, Armelle Lecarpentier, June 2006.

of national gas consumption. The Magreb pipeline increased capacity in 2006 by 1-2% of annual Spanish demand

Enagas had a "winter performance plan" in place in 2006 - 2007. LNG commercial storage was regulated between a minimum 3 days and maximum 5 days per operator, intended to stop hoarding, but also ensuring some storage.

Hungary

Natural gas is the most important fuel in Hungary, representing 44% of the country's total primary energy supply in 2005. This is significantly higher than the IEA European average of 24.3% or the OECD total of 21.9% in 2005. The supply of natural gas has increased by an average of 2.1% per year since 1990.

The Hungarian government predicts that supply of natural gas will increase slightly by 3.2% until 2010 and more rapidly thereafter. Most of the additional demand is expected to come from gas use in power generation.

Natural gas is an important energy source for power generation and heat production in Hungary. In 2004, natural gas accounted for 35% of Hungarian power generation. Heat and electricity production together used 28% of total gas supply in that year. Residential and commercial gas use accounted for about half of all gas supplied in Hungary.

Because of the growing use in the residential sector and the shrinking use in the industrial sector, seasonal demand fluctuations are becoming larger. The ratio between average summer and winter consumption now stands at 1 to 4. Local gas distribution networks cover 40% of household energy demand in the country.

Hungary produced 3 bcm of natural gas in 2005, a significant decline of 38% from the production of 4.9 bcm in 1990. It is expected that production will decline further in the future to 2.3 bcm in 2010. Exploration activity is focused on central Hungary.

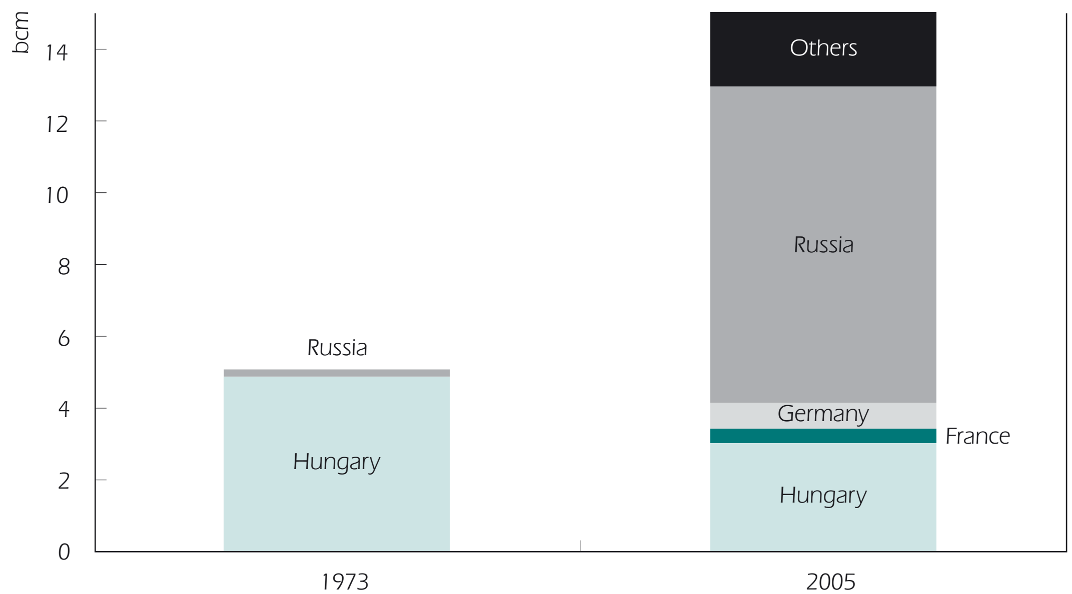
Domestic production accounted for 19.3% of total gas supply in Hungary in 2005. The main producer of natural gas is the petroleum company Mol. The only other producer is Winstar, with a production of 0.3 bcm in 2005. Proven reserves of Mol fell from 29.25 bcm in 2004 to 27.5 bcm in 2005. A potential new producer, Toreador, plans to open production from a gas condensate field at Örmenyes.

With the predicted increase in demand and reduction in production over the coming years, the Hungarian government expects that domestic production will cover 14.4% of demand by 2010 and 9% by 2020.

Special royalties are paid on gas production from wells that started before 1998, to fund the household gas subsidy. In 2006, the Hungarian government and Mol renegotiated the royalty agreement, to incentivize Mol to consider increased investment in continued production from these wells.

Hungary has not been fully self-sufficient in gas since 1970s and today relies on imports from Russia. Total imports in 2005 reached 12 bcm. Of this, 2.2 bcm

Figure 80 **Hungary's gas sources**



Source: *Natural Gas Information 2006*, IEA.

were contracted from new suppliers such as Gaz de France, with physical supply being 100% from Russia. The Russian share of Hungary's gas supply is nearing 80% of contracted volume and this could increase to 85% in 2020 according to the government's scenario, if no measures for import source diversification are taken.

Imports are under five long-term supply contracts held by Panrusgaz, originally a joint-venture of Gazprom and Mol with each owning 50% of the shares. With the sale of the gas supply and storage business from Mol to E.On in 2006, E.On took over Mol's share of the joint-venture.

The country's transport system had 5 194 km of transmission pipelines as of the end of 2005. Distribution networks total more than 79 000 km. The main international connections by pipeline are with Ukraine, Austria and Serbia. The Ukraine pipeline is the prime import route for gas into Hungary, while the Austrian pipeline is primarily used to balance the system and at times of high demand. The Serbian pipeline serves as a transit pipeline, through which gas is sent into Balkans under a 20-year contract concluded in 1998. At the moment, only the Ukraine pipeline has spare capacity. Capacity at the entry points is allocated by auction.

Further international connections are under discussion, including the Nabucco pipeline, an extension of the Blue Stream pipeline (which was agreed between the Russian and Hungarian companies in March 2006) and the construction of an LNG terminal on the Croatian island of Krk, with a pipeline connection into Hungary. The aim of Nabucco, a major gas transit line from

Table 38 **Entry capacity of the gas system in Hungary**

Entry point	Capacity (bcm per year)	Deliverability (mcm per day)
Beregdaróc (from Ukraine)	10.0	29.5
Mosonmagyarróvár (from Austria)	4.4	12.0
Domestic production (7 locations)	3.5	11.5
Storage (5 locations)		47.5
Total	**17.9**	**100.5**
Peak demand in 2005		89.0
Transit		12.0

Source: Mol.

the Caspian region through the Balkans, would be to secure the increasing natural gas demand of European Union member countries and southeast European countries. A number of regional gas companies are examining the possibility to build the line with a yearly capacity of 30 bcm.

A number of projects aimed at increasing regional networks are being evaluated. Mol is interested in establishing a transit pipeline serving Romania and negotiations are in progress with Romgaz about a pipeline with a 1.0 - 1.5 bcm per year capacity, which would need two years to be built at an estimated cost of USD 30 million. Mol and INA also decided on the evaluation of a Croatian transit connection point with a delivery amount of 2 bcm per year and an estimated capital cost of over USD 100 million. These projects are at a very early stage of development.

Following the discovery of natural gas in Hungary in the 1960s, a gas transmission network was built up from 1963 to reach a total length of 5 194 km in 2005. The average age of the system is 25 years and half of the system was built between 1963 and 1980. Inspections using advanced methods have revealed that the majority of the system is in need of major reconstruction and in some areas complete replacement. As a consequence, the transmission tariff has been amended to create an incentive for investment by the system operator.

The transmission system is operated by Mol's gas business and regulated by the Hungarian Energy Office. The price for the system use is based on an entry/exit calculation since 2005. Prior to this it was a flat rate.

A temporary network and commercial code was published in 2003, regulating third party access (TPA) to the transmission and distribution network and the storage system, including prices and co-operation rules. This was followed by a government decree in 2004 and the Gas Act of 2005.

Under the network code, the natural gas transmission company has to publish on its homepage the available capacity for the following 12 months in a monthly breakdown at entry and exit points of the network. Also, the annual maintenance plan of the interoperable natural gas system has to be published by February 15 each year. Spare capacity of the transmission system and storages has to be published 15 months in advance under the code.

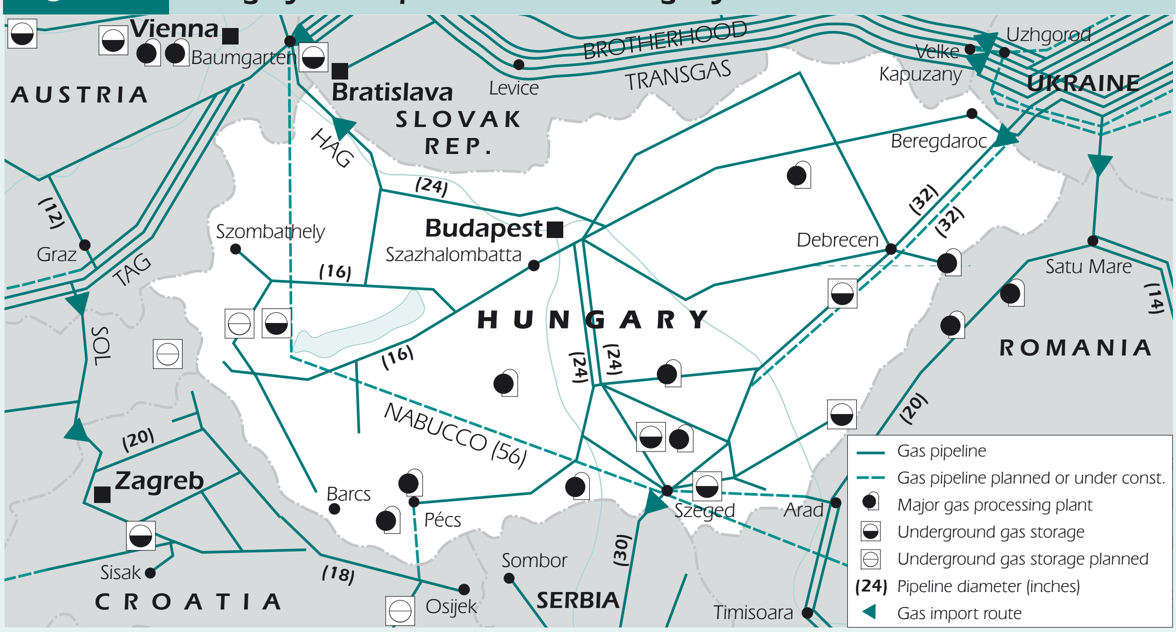
The code also provides detailed rules for contracting capacity and describes the scope of basic services provided by system operators. It identifies possible and mandatory contractual relationships of the new market structure, including not only commercial agreements, but also those of various forms of cooperation between system users and the operator.

Underground storage plays a very important role in Hungary considering the high seasonality of demand, the inflexible structure of demand and the need to cover the daily peak during winter, almost half of which is household heating demand. Current facilities are all depleted gas fields.

In 2006, Mol sold four and leased out one of its five storage facilities with a total capacity of 3.4 bcm and a daily withdrawal capacity of 47.5 mcm to E.On Ruhrgas International. Third party access to the underground storage has been implemented for the competitive gas market, while the regulated tariffs for supply of the captive markets now contain incentives for new investments into underground storage.

Following the supply interruption of January 2006, which cut the country's gas supply by up to 20% over several days, the Parliament approved a new law, the Act XXVI/2006 on Safety Stockpiling of Natural Gas in February 2006. According

Figure 81 **Hungary's transportation and storage system**



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Source: The Petroleum Economist Ltd..

Table 39 Underground gas storage in Hungary

	Working capacity (mcm)	Equivalent days of national gas consumption	Deliverability (mcm per day)
Pusztaederics	330		2.7
Zsana	1 300		21.0
Algyø-Maros-1	150		2.2
Kardoskút-Pusztaszøløs	200		2.4
Hajdúszoboszló	1 400		19.2
Total	**3 380**	**102.8**	**47.5**

Source: Mol

to the act, new underground gas storage with a total capacity of 1.2 bcm or more and deliverability of 29 mcm per day has to be constructed and become operational by 2010.

The legal framework under which the storage will be managed is similar to that for oil emergency storage, in that it is managed by the Hungarian Hydrocarbon Stockpiling Association (MSZKSZ), financed by the gas suppliers. The Hungarian government will have the right to initiate a stock draw. At the moment, the conditions under which this right can be exercised have not been clarified. All gas companies operating in Hungary have to become a member of the MSZKSZ. The level of their contribution fee and how it will be determined is unclear at this time and will depend on the cost of creating and operating the storage facility. One possible option is for the cost to be covered by an additional charge on the current regulated final tariffs if a new storage is installed. The possible cost is estimated at 2% of the final tariff by the MSZKSZ.

The cost of the project is estimated to be USD 750 million. The MSZKSZ carried out a tender to select a company for the building and operating of the facility and MOL was selected in November 2006. MOL is expected to construct the facility in a joint venture with the state. Until then, from October 2006, 150 mcm, then from October 2007 until December 2009, 300 mcm security reserve must be stored in the existing storages which can only be used in a crisis situation.

European Union Directive 2004/67/EC

Europe as a whole depends heavily on outside supply sources in meeting natural gas demand and as noted earlier, the dependence is expected to grow further in coming years. Although the gas supply security issue has attracted particular attention after the Russia - Ukraine gas crisis of January 2006, the EU had put a great emphasis on this issue before this time. EU's framework of security of gas supply is defined in EU Council Directives.

Directive 2003/55/EC, which set the market opening schedule and entered into force in July 2004, stipulated that these "common rules for the internal market in natural gas" include obligations (in Article 13) on Member States regarding monitoring of security of supply.

Directive 2004/67/EC, which entered into force in May 2006, includes provisions "concerning measures to safeguard security of natural gas supply." The Directive states that supplies to household customers must be protected under extreme conditions. It also includes references to storage, long-term contracts, bilateral agreements, incentives for investment and market liquidity, as well as defining a major supply disruption as losing 20% of third party gas. It also sets up emergency procedures and a Gas Co-ordination Group.

This Group, set up to co-ordinate supply security, had its first meeting in January 2006, even before the official entry into force of the Directive itself. The sole topic of the meeting was the Russia-Ukraine gas supply disruption.

The second meeting in October 2006 discussed rules of procedure, a work plan and to bring Russian and Ukrainian gas companies together to share views and information. The January 2007 meeting discussed the gas supply problems between Belarus and Russia.

The Gas Co-ordination Group's draft work plan for EU gas supply security seeks to:

- Provide a clear view of physical gas supply security.
- Assess effectiveness of implementation of measures.
- Provide a common understanding of "major supply disruption" (20% loss of third party gas).
- Define a compensation mechanism.
- Identify and assess forthcoming challenges.

The European Council in March 2007 highlighted the need for a "thorough analysis of the availability and costs of gas storage falicities in the EU" as one of the measures to enhance security of supply.

ANNEX B: CONTRACTUAL GAS FLOWS INVOLVING OECD COUNTRIES

Figure 82 Gas flows based on 2005 IEA data: North America

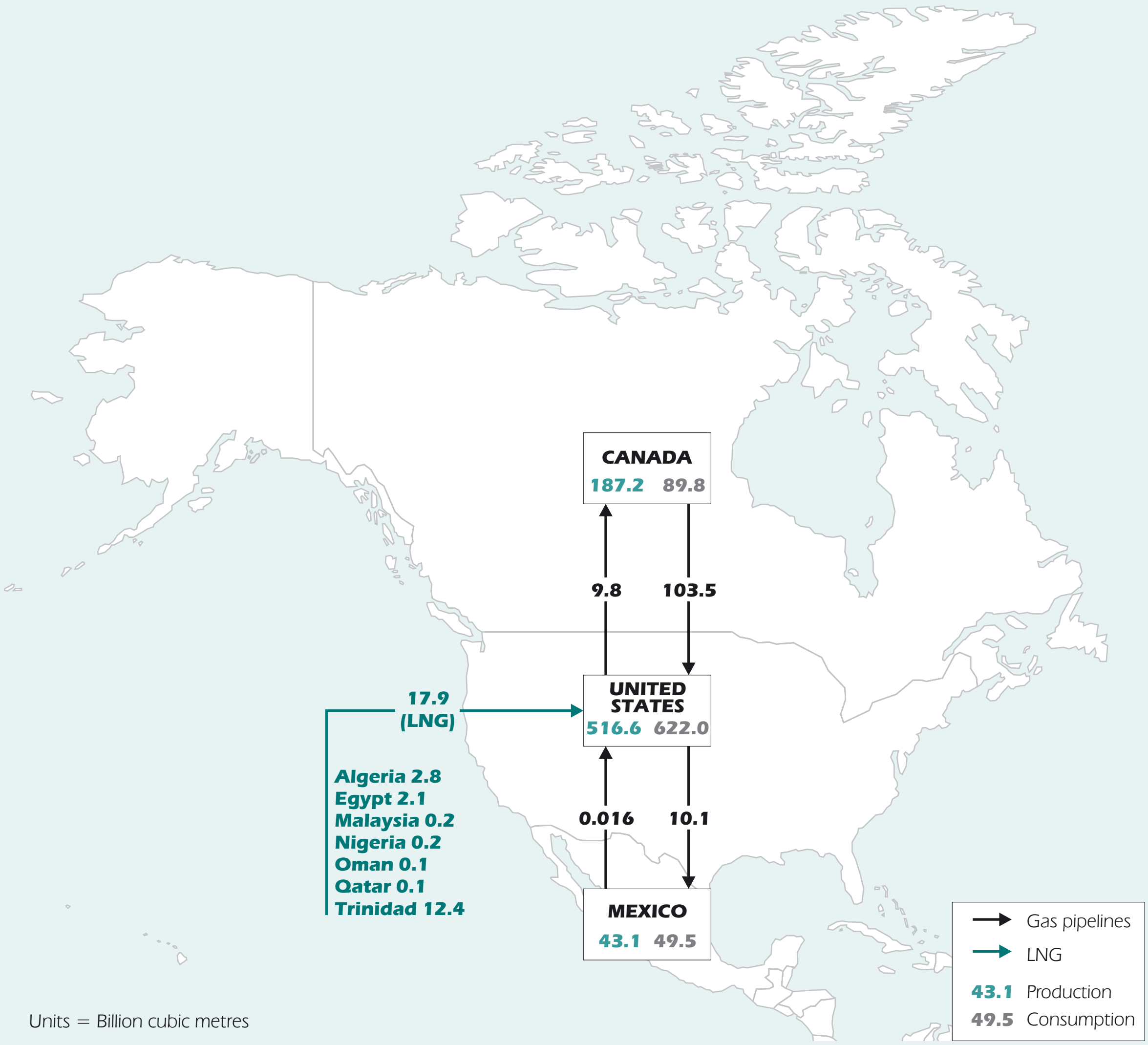

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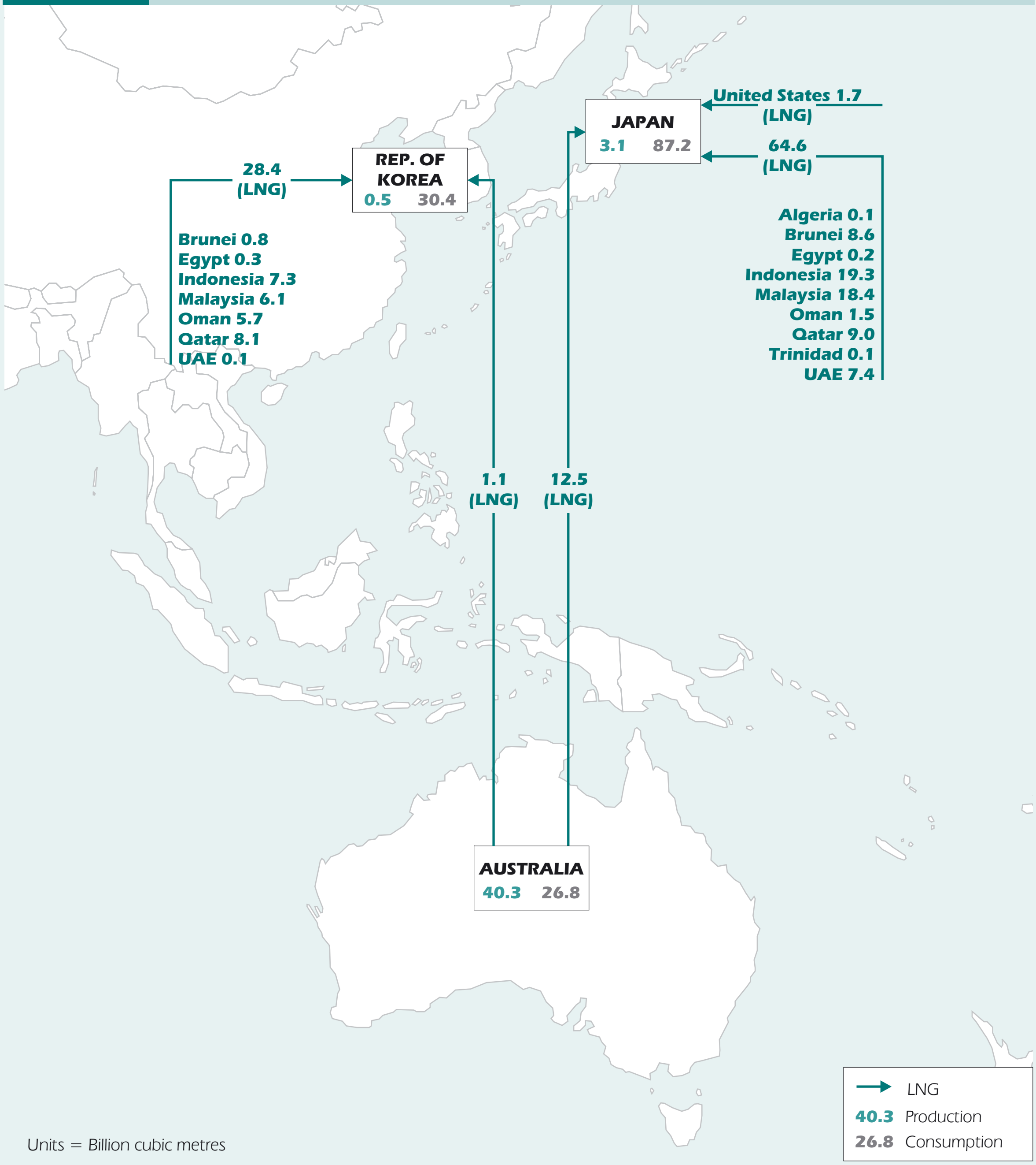
Figure 83 Gas flows based on 2005 IEA data: Asia Pacific



Units = Billion cubic metres

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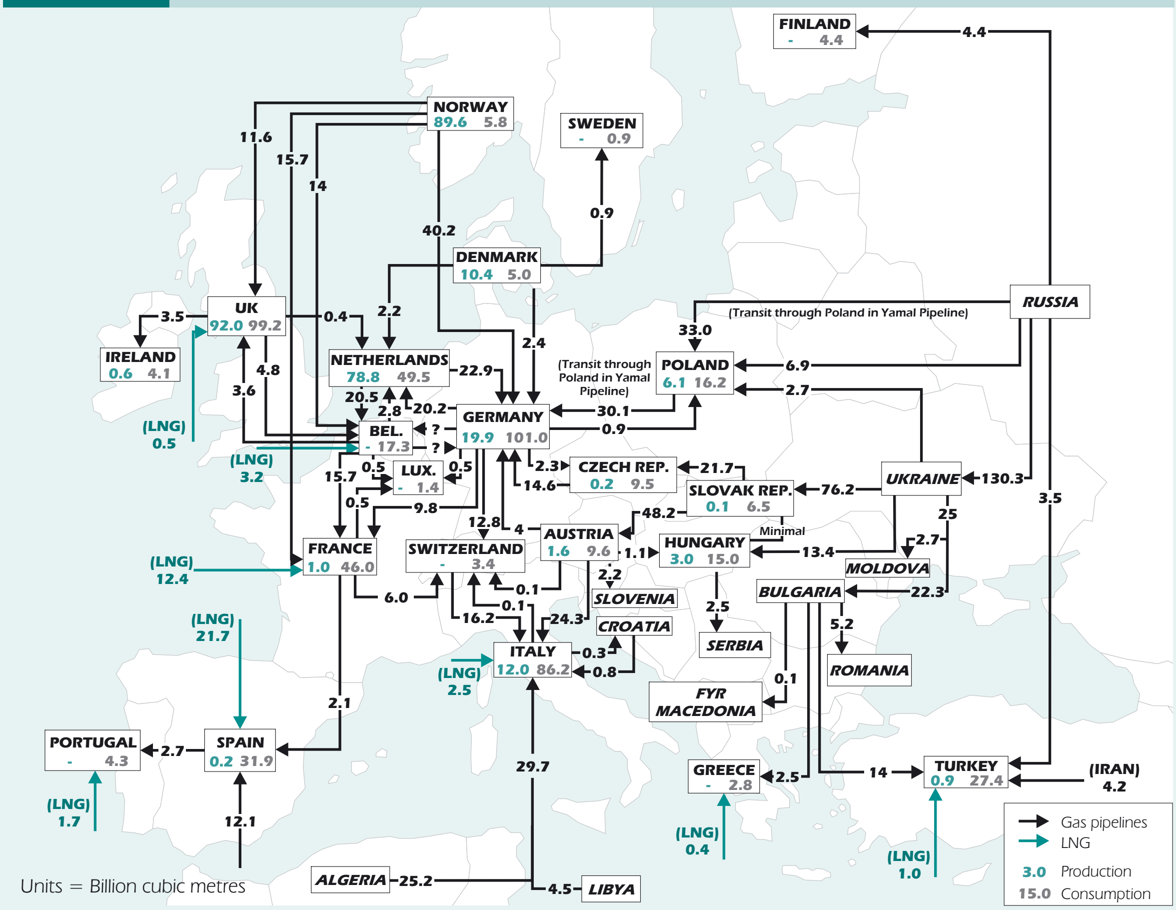
Figure 84 Gas flows based on 2005 IEA data: Europe



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ANNEX C: ABBREVIATIONS

ANWR	Arctic National Wildlife Refuge (in Alaska, the United States)
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, the United States
E&P	Exploration and production
EPC	Engineering, procurement and construction
EU	European Union
FERC	Federal Energy Regulatory Commission, the United States
FSU	Former Soviet Union
GHG	Greenhouse gas
GTL	Gas-To-Liquids
GW	Gigawatt (10^9 watts)
GWh	Gigawatt hour
HDD	Heating degree-days
IEA	International Energy Agency
IOC	International oil company
IPE	International Petroleum Exchange, based in the United Kingdom
IPP	Independent power producer
ISO	Independent system operator
IUK	Interconnector UK
JCC	Japan Crude Cocktail, the average price of crude oil imported into Japan
kb/d	thousand barrels per day
kW	kilowatt (10^3 watts)
kWh	kilowatt hour
LDC	Local distribution company
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas (propane, butane)

mb/d	million barrels per day
MBtu	Million British thermal units
mcm	million cubic meters
MENA	Middle East and North Africa
MJ	megajoule
Mtoe	million tonnes of oil equivalent
mtpa	million tonnes per annum
MW	Megawatt (10^6 watts)
MWh	Megawatt hour
NBP	National Balancing Point (a virtual trading point for gas in the United Kingdom)
NDRC	National Development and Reform Commission, China
NEGP	North-European Gas Pipeline (current Nord Stream Pipeline)
NGL	Natural gas liquid
NIMBY	Not in my back yard
NOC	National oil company
NWS	North West Shelf (an Australian LNG venture)
NYMEX	New York Mercantile Exchange, in the United States
OCGT	Open-cycle gas turbine
OCS	Outer continental shelf
OECD	Organisation for Economic Co-operation and Development
Ofgem	Office of Gas and Electricity Markets, the United Kingdom
OPEC	Organisation of Petroleum Exporting Countries
PSA (PSC)	Production sharing agreement (contract)
SPA (SPC)	Sale and purchase agreement (contract)
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	Terawatt hour
USD	United States Dollar
WAGP	West African Gas Pipeline
WEO	World Energy Outlook (IEA publication)
WTI	West Texas Intermediate (benchmark crude oil in the United States)

ANNEX D: GLOSSARY

Associated gas	Natural gas found mixed with oil in underground hydro-carbon reservoirs, released as a by-product of oil production.
Balancing	The requirement to equal supply and demand in a pipeline system over a certain period.
Base gas	Gas required in a storage facility to maintain sufficient pressure (sometimes: cushion gas).
Base-load capacity	Capacity of liquefaction plant or regasification terminal that is supposed to be processed in a year.
Base-load power	Power generation units used to meet demand around the clock.
Basis differential	The difference between spot cash prices at different locations at the same time.
Brownfield project	Expansion project to an existing plant, or alteration project from a different or mothballed plant.
City gate	The point which a local distribution company (LDC) receives gas from a pipeline or transmission system.
Condensate	Light hydrocarbons existing as vapour in natural gas reservoirs that condense to liquid at normal temperature and pressure.
Cushion gas	See: base gas.
Dry gas	Gas that does not contain heavier hydrocarbons, or that has been treated to remove heavier hydrocarbons.
Greenfield project	Project constructed from the ground up, a brand-new project.
Feedstock gas	Gas used as feedstock for petrochemical or fertiliser plants, or used to liquefy into LNG.
Flaring	Burning off unused natural gas, typically at an oil producing field where the associated gas cannot be economically utilised. Sometimes gas is flared as a safety measure to mitigate overpressure of other gas systems.
Henry Hub	Pipeline interconnection in Louisiana, the United States, where a number of pipelines meet, which is the standard delivery point for the NYMEX natural gas contracts in the United States, used as the benchmark price in the United States Gulf Coast for domestic and international gas transactions.

Hub	Physical or virtual location where multiple natural gas pipelines interconnect or natural gas is supposed to be delivered between multiple parties.
Indexation	Linking the gas price in a contract to published prices or other indicators.
Injection	The act of putting gas into a storage facility.
LNGRV (LNG regasification vessel)	An LNG carrier ship which is equipped with onboard regasification facilities.
Long-term contract	A supply contract of gas deliveries lasting years, typically 20-25 years for LNG and international long-haul pipeline trades to support big investment and 2-5 years for domestic industrial-sector sales in certain countries.
Net-back price	The effective wellhead price to the producer of natural gas, the downstream market price less the charge for delivery.
Non-associated gas	Natural gas not in contact with crude oil in the reservoir.
Offtake	To take a delivery of gas or LNG at a certain point.
Open access	Natural gas transportation or LNG regasification service available to all shippers on a non-discriminatory basis.
Open season	A procedure conducted by an infrastructure facility (pipeline, storage, or LNG regasification terminal) owner to gauge potential users' financial interest in the capacity of the facility.
Peaking (or peak-shaving) capacity	The maximum capacity of power generation, storage withdrawal, or LNG regasification send-out, during the highest daily, weekly, or seasonal demand period.
S-Curve	A pricing mechanism that uses a linkage to an indicator (typically seen in Asian LNG contracts using the JCC oil price as an indicator), where the rates of gas price increase or decrease compared to indicator are slowed outside of a certain indicator range so that both buyers and sellers are protected from moves of the indicator outside a certain range.
Sour gas	Natural gas that contains significant hydrogen sulphide content.
Take-or-pay	A clause in a gas (or an LNG) supply contract that dictate a minimum quantity of gas (or LNG) be paid for to the seller, irrespective of whether delivery is accepted by the buyer.

Throughput	The volume of gas transported through a pipeline, or treated by a treatment facility.
Tolling	A fee-based service where the service providing power generator receives fuel from the beneficiary and delivers electric power to the same beneficiary in return for the service fee.
Train	An LNG 'train' consists of the gas processing and liquefaction units to treat and liquefy feedstock gas.
Unbundling	Separating different elements of gas services, in particular, transportation/distribution and commodity trading, either on a legal or accounting basis.
Wellhead	A commonly used expression of the upstream end of natural gas value chain, derived from the original meaning of the top of a production well in a gas field.
Wet gas	Gas that contains heavier hydrocarbons or associated gas that has not been processed yet.
Withdrawal	Sending out gas from a gas storage facility.
Working gas	Gas expected to be withdrawn from a natural gas storage facility during usual operations.

ANNEX E: CONVERSION FACTORS

Table 40 **Conversion factors for natural gas volume**

To: From:	bcm per year	million tonnes per year	bcf/d	Tcf per year	PJ per year	TWh per year	MBtu per year	Mtoe per year
	multiply by:							
bcm per year	1	0.7350	0.09681	0.03534	40.00	11.11	3.7912×10^{7}	0.9554
million tonnes per year	1.360	1	0.1317	0.04808	54.40	15.11	5.16×10^{7}	1.299
bcf/d	10.33	7.595	1	0.3650	413.2	114.8	3.91×10^{8}	9.869
Tcf per year	28.30	20.81	2.740	1	1,132	314.5	1.07×10^{9}	27.04
PJ per year	0.02500	0.01838	0.002420	0.0008834	1	0.2778	9.47×10^{5}	0.02388
TWh per year	0.09000	0.06615	0.008713	0.003180	3.600	1	3.41×10^{6}	0.08598
MBtu per year	2.638×10^{-8}	1.939×10^{-8}	2.554×10^{-9}	9.32×10^{-10}	1.055×10^{-6}	2.93×10^{-7}	1	2.520×10^{-8}
Mtoe per year	1.047	0.7693	0.1013	0.03698	41.87	11.63	3.97×10^{7}	1

Note: Based on gas with 40 MJ/m^3.

Table 41 **Conversion factors for natural gas price**

From: / To:	USD /MBtu	USD /1 000 m^3	USD / tonne
USD /MBtu	1	37.912	51.41815
USD /1,000 m^3	0.02638	1	1.35625
USD / tonne	0.01945	0.7373	1

Note: Based on gas with 40 MJ/m^3.

ANNEX F: LNG REGASIFICATION TERMINALS

Table 42 LNG regasification terminals

Country	Terminal	Capacity (bcm per year)	(mtpa)	Storage m³	Start	Status
Japan	Chita Kyodo	10.4	7.6	300 000	1978	Operation
	Chita	16.6	11.5	640 000	1983	Operation
	Chita-Midorihama Works	7.3	5.4	200 000	2001	Operation
	Fukuoka	1.2	0.9	70 000	1993	Operation
	Futtsu	27.4	20.1	1 110 000	1985	Operation
	Hatsukaichi	0.8	0.6	170 000	1996	Operation
	Higashi-Ohgishima	21.1	15.5	540 000	1984	Operation
	Himeji	6.8	5.0	740 000	1984	Operation
	Himeji LNG	11.6	8.5	520 000	1979	Operation
	Joetsu				2012	Proposed
	Kagoshima	0.3	0.2	86 000	1996	Operation
	Kawagoe	7.5	5.5	480 000	1997	Operation
	Kawagoe expansion			360 000	2011	Planned
	Mizushima	0.8	0.6	160 000	2006	Operation
	Mizushima expansion	1.4	1.0	160 000	2012	Planned
	Nagasaki	0.2	0.1	35 000	2003	Operation
	Negishi	16.5	12.1	1 180 000	1969	Operation
	Niigata	12.2	9.0	720 000	1984	Operation
	Ohgishima	8.1	6.0	600 000	1998	Operation
	Oita	6.6	4.9	460 000	1990	Operation
	Sakai	2.8	2.1	140 000	2006	Operation
	Sakaide	0.6	0.4	180 000	2010	Planned
	Senboku I	3.4	2.5	180 000	1972	Operation
	Senboku II	17.5	12.9	1 585 000	1977	Operation
	Shin-Minato	0.4	0.3	80 000	1997	Operation
	Sodegaura	39.9	29.3	2 660 000	1973	Operation
	Sodeshi	1.2	0.9	177 200	1996	Operation
	Sodeshi expansion			160 000	2010	Planned
	Tobata	9.3	6.8	480 000	1977	Operation
	Wakayama				TBD	Proposed
	Yanai	3.3	2.4	480 000	1990	Operation
	Yokkaichi LNG Centre	9.7	7.1	320 000	1988	Operation
	Yokkaichi Works	0.9	0.7	160 000	1991	Operation
Korea	Pyeong-Taek	26.1	19.2	1 000 000	1986	Operation

Table 42 LNG regasification terminals (cont.)

Country	Terminal	Capacity (bcm per year)	(mtpa)	Storage m^3	Start	Status
	Pyongtaek 2	4.3	3.2	280 000	2007	Construction
	Pyongtaek 2	4.3	3.2	280 000	2008	Construction
	Pyongtaek 2	4.3	3.2	200 000	2010	Planned
	Pyongtaek 2	4.3	3.2	200 000	2012	Planned
	In-Chon	37.9	27.9	2 480 000	1996	Operation
	In-Chon expansion	12.2	8.9	400 000	2009	Construction
	Tong-Yeong	15.3	11.2	980 000	2002	Operation
	Tong-Yeong expansion			420 000	2006	Operation
	Tong-Yeong expansion 2	6.4	4.7	1 000 000	2009	Construction
	Gwangyang	2.4	1.8	300 000	2005	Operation
	Samcheok or Boryeong			1 000 000	2013	Proposed
Chinese Taipei	Yung-An	24.3	17.9	690 000	1990	Operation
	Taichung	4.1	3.0	480 000	2009	Construction
China	Guangdong Dapeng	5.0	3.7	480 000	2006	Operation
	Guangdong Dapeng 2	3.4	2.5	160 000	2008	Construction
	Fujian	3.5	2.6	320 000	2008	Construction
	Shanghai LNG	4.1	3.0	495 000	2009	Construction
	Liaoning, Dalian	4.1	3.0		2011	Planned
	Zhejiang, Ningbo	4.1	3.0		2010+	Planned
	Hong Kong Black Point or Tai A	3.5	2.6		2011	Planned
	Shandong, Qingdao	4.1	3.0		n.a.	Planned
	Jiangsu, Rudong	4.8	3.5		2011	Planned
	Hebei, Tangshan	4.1	3.0		2010+	Planned
India	Dahej	8.9	6.5	320 000	2004	Operation
	Hazira	3.7	2.7	320 000	2005	Operation
	Ratnagiri (Dabhol)	7.5	5.5	480 000	2008	Completed
	Dahej expansion	8.2	6.0	320 000	2008	Construction
	Kochi	3.4	2.5	220 000	2010	Planned
Singapore	Jurong Island	4.1	3.0	300 000	2012	Planned
Thailand	Map Ta Phut	6.8	5.0	360 000	2011	Planned
Pakistan	Port Qasim	4.8	3.5	300 000	2009	Planned
Mexico (West)	Costa Azul	10.3	7.6	320 000	2008	Construction
	Costa Azul expansion	10.3	7.6		2010+	Planned
	Manzanillo	5.0	3.7	300 000	2011	Planned

Table 42	LNG regasification terminals (cont.)					
Country	**Terminal**	**Capacity (bcm per year)**	**(mtpa)**	**Storage m³**	**Start**	**Status**
Canada (West)	Kitimat LNG	6.3	4.6	160 000	2014	Planned
Chile	Quintero	3.4	2.5	320 000	2009	Planned
	Northern mining region	1.8	1.3		2010	Planned
France	Fos Tonkin	7.0	5.1	150 000	1972	Operation
	Montoir de Bretagne	10.0	7.4	360 000	1980	Operation
	Fos Cavaou	8.3	6.1	330 000	2007	Construction
	Montoir expansion I	2.5	1.8	-	2011	Planned
	Montoir expansion II	4.0	2.9	120 000	2014	Planned
	Bordeaux (Le Verdon)	6.0	4.4		2011	Planned
	Bordeaux (Le Verdon)	4.0	2.9		TBD	Proposed
	Le Havre (Antifer)	8.0	5.9		2011	Planned
	Dunkerque	6.0	4.4		2011	Planned
Spain	Barcelona	13.9	10.2	390 000	1969	Operation
	Huelva	9.7	7.1	310 000	1988	Operation
	Cartagena	7.4	5.4	287 000	1989	Operation
	Bilbao	8.0	5.9	300 000	2003	Operation
	Sagunto	6.0	4.4	300 000	2006	Operation
	Barcelona No.6	3.4	2.5	150 000	2006	Operation
	Huelva No. 4	3.9	2.9	150 000	2006	Operation
	Mugardos (El Ferrol)	3.6	2.6	300 000	2007	Construction
	Cartagena expansion	2.5	1.9		2006	Operation
	Cartagena No. 4		-	150 000	2008	Construction
	Bilbao No. 3			150 000	2008	Construction
	Sagunto expansion	2.0	1.5		2008	Construction
	Sagunto No. 3			150 000	2009	Construction
	Huelva No. 5			150 000	2009	Construction
	Barcelona No. 7			150 000	2009	Construction
	El Musel	7.0	5.1	300 000	2010	Planned
	Barcelona No. 8			150 000	2010	Planned
	Cartagena No. 5			150 000	2010	Planned
	Bilbao No. 4	2.5	1.8	150 000	2010	Planned
	Sagunto No. 4			150 000	2011	Planned
	Canary Islands			150 000	2009+	Planned
Portugal	Sines	5.5	4.0	240 000	2004	Operation
Italy	Panigaglia	3.5	2.6	100 000	1969	Operation

Table 42 LNG regasification terminals (cont.)

Country	Terminal	Capacity (bcm per year)	(mtpa)	Storage m³	Start	Status
	Rovigo	8.0	5.9	250 000	2008	Construction
	Livorno offshore	3.0	2.2	137 500	2009	Construction
	Brindisi	8.0	5.9	320 000	2010+	Suspended
	Panigaglia expansion	4.5	3.3		2010+	Planned
Belgium	Zeebrugge	4.5	3.3	261 000	1987	Operation
	Zeebrugge expansion I	4.5	3.3	140 000	2007	Construction
	Zeebrugge expansion II	9.0	6.6		2011	Planned
Netherlands	Rotterdam (Gate)	8.0	5.9	360 000	2010	Planned
	Rotterdam (LionGas)	9.0	6.6		2010	Planned
	Rotterdam (offshore)					Proposed
	Eemshaven	5.0	3.7		2011	Planned
Germany	Wilhelmshaven	10.0	7.4		2011	Proposed
Poland	Swinoujscie	2.5	1.8		2011+	Proposed
United Kingdom	Isle of Grain	4.9	3.6	200 000	2005	Operation
	Teesside	4.0	2.9		2007	Operation
	South Hook I	10.6	7.8	465 000	2008	Construction
	Dragon LNG	6.0	4.4	336 000	2008	Construction
	Isle of Grain expansion I	8.7	6.4	370 000	2008	Construction
	South Hook II	10.6	7.8	310 000	2009	Construction
	Isle of Grain expansion II	6.7	4.9	200 000	2010+	Planned
	Dragon LNG expansion	3.0	2.2	168 000	2011	Proposed
Turkey	Marmara Ereglisi	6.5	4.8	255 000	1994	Operation
	Aliaga	6.0	4.4	280 000	2006	Operation
Greece	Revithoussa	1.4	1.0	130 000	2000	Operation
Croatia	Krk Island	8.0	5.9		2012	Proposed
United States (East)	Everett	8.3	6.1	155 000	1971	Operation
	Lake Charles	13.1	9.6	285 000	1982	Operation
	Lake Charles expansion	6.0	4.4	140 000	2006	Operation
	Elba Island	15.5	11.4	338 720	1978	Operation
	Elba Island expansion I	4.2	3.1	160 000	2010	Planned
	Elba Island expansion II	5.1	3.7	160 000	2012	Planned
	Cove Point	10.3	7.6	485 000	1978	Operation
	Cove Point expansion	8.3	6.1	320 000	2008	Construction
	Gulf Gateway	4.9	3.6		2005	Operation
	Northeast Gateway	4.1	3.0		2007	Planned

Table 42 LNG regasification terminals (cont.)

Country	Terminal	Capacity (bcm per year)	(mtpa)	Storage m³	Start	Status
	Cameron	15.5	11.4	480 000	2008	Construction
	Cameron expansion	11.9	8.7	160 000	2011	Planned
	Freeport	15.5	11.4	320 000	2008	Construction
	Sabine Pass	26.9	19.8	480 000	2008	Construction
	Sabine Pass expansion	14.5	10.7	320 000	2009	Construction
	Golden Pass	20.7	15.2	800 000	2009	Construction
	Neptune	5.2	3.8		2009	Planned
	Ingleside Energy	10.3	7.6	320 000	2010+	Planned
	Corpus Cristi	26.9	19.8	480 000	2010+	Planned
	Gulf Landing	10.3	7.6		2010+	Planned
	Crown Landing	12.4	9.1	360 000	2011	Planned
	Creole Trail	34.1	25.1	640 000	2011	Planned
	Port Arthur	15.5	11.4	480 000	2011	Planned
	Port Arthur expansion	15.5	11.4	480 000	2014	Planned
	Main Pass Energy Hub	10.3	7.6		2012	Planned
Puerto Rico	Penuelas	4.0	2.9	160 000	2000	Operation
Mexico (East)	Altamira	5.2	3.8	450 000	2006	Operation
Canada (East)	Canaport	10.3	7.6	320 000	2008	Construction
	Bear Head	10.3	7.6	360 000	2011	Halted
	Cacouna Energy	5.2	3.8		2010+	Planned
	Maple LNG	10.3	7.6	480 000	2010+	Planned
	Rabaska LNG	5.2	3.8		2010+	Planned
Dominican Republic	Punta Caucedo	2.4	1.8	160 000	2003	Operation
Brazil	Guanabara Bay	4.8	3.5		2009	Planned
	Pecem, Northeast	2.0	1.5		2009	Planned
Operational total	**as of March 2007**	**545.1**	**400.0**	**27 299 920**		
Expected	**in end 2010**	**846.0**	**621.2**	**40 463 420**		
Proposed total		**1 188.6**	**873.0**	**48 781 420**		

ANNEX G: LNG LIQUEFACTION PLANTS

Table 43 LNG liquefaction plants

Region/Country	Project	Location	Capacity (mtpa)	Capacity (bcm per year)	Status	Start
Asia Pacific						
Indonesia	Bontang	East Kalimantan	22.3	30.3	Existing	1977
	Arun	North Smatra	6.8	9.3	Existing	1978
	Tangguh	Bintuni Bay, Papua	7.6	10.3	Under construction	2008
	Donggi	Central Sulawesi	2.0	2.7	Planned	2012
Malaysia	MLNG	Bintulu, Sarawak	8.1	11.0	Existing	1983
	MLNG Dua	Bintulu, Sarawak	7.8	10.6	Existing	1995
	MLNG Tiga	Bintulu, Sarawak	6.8	9.3	Existing	2003
Brunei	Brunei LNG	Lumut	7.2	9.8	Existing	1972
Australia	North West Shelf 1-4	Burrup Peninsula	11.9	16.2	Existing	1989
	North West Shelf 5	Burrup Peninsula	4.4	6.0	Under construction	2008
	Darwin LNG	Point Wickham	3.7	5.0	Existing	2006
	Pluto	Burrup Peninsula	6.0	8.2	Engineering	2010
	Gorgon	Barrow Island	10.0	13.6	Engineering	2011
	Ichthys	Kimberly	6.0	8.2	Engineering	2012
Russia	Sakhalin II	Prigorodnoye	9.6	13.1	Under construction	2008
Alaska	Kenai LNG	Cook Inlet	1.5	2.0	Existing	1969
Peru	Peru LNG	Pampa Melchorita	4.4	6.0	Under construction	2010
Middle East						
Qatar	Qatargas	Ras Laffan	9.9	13.5	Existing	1997
	RasGas	Ras Laffan	6.6	9.0	Existing	1999
	RasGas II (Trains 3-4)	Ras Laffan	9.4	12.8	Existing	2004
	RasGas II (Train 5)	Ras Laffan	4.7	6.4	Existing	2007
	Qatargas II (Train 4)	Ras Laffan	7.8	10.6	Under construction	2008
	Qatargas II (Train 5)	Ras Laffan	7.8	10.6	Under construction	2008
	Qatargas III (Train 6)	Ras Laffan	7.8	10.6	Under construction	2009
	Qatargas IV (Train 7)	Ras Laffan	7.8	10.6	Under construction	2010
	RasGas III (Train 6)	Ras Laffan	7.8	10.6	Under construction	2008
	RasGas III (Train 7)	Ras Laffan	7.8	10.6	Under construction	2009
Oman	Oman LNG	Qalhat	7.2	9.8	Existing	2000

Table 43 **LNG liquefaction plants (cont.)**

Region/Country	Project	Location	Capacity (mtpa)	Capacity (bcm per year)	Status	Start
	Qalhat LNG	Qalhat	3.6	4.9	Existing	2005
UAE	Adgas	Das Island	5.8	7.9	Existing	1977
Yemen	Yemen LNG 1	Bal Haf	3.4	4.6	Under construction	2008
	Yemen LNG 2	Bal Haf	3.4	4.6	Under construction	2009
Iran	Pars LNG		10.0	13.6	Planned	2011
	Persian LNG		8.0	10.9	Planned	2012
	Iran LNG	Bandar Tombak	9.0	12.2	Planned	2012
Egypt	Segas	Damietta	4.8	6.5	Existing	2005
	Segas Train 2	Damietta	5.3	7.2	Planned	2011
	Egyptian LNG 1	Idku	3.6	4.9	Existing	2005
	Egyptian LNG 2	Idku	3.6	4.9	Existing	2005
	Egyptian LNG 3	Idku	3.6	4.9	Planned	2011
Libya	Marsa el Brega	Marsa el Brega	0.8	1.0	Existing	1970
	Marsa el Brega	Marsa el Brega	2.4	3.3	Planned	2010
Algeria	Skikda GL1 KII	Skikda	3.1	4.3	Existing	1972
	Arzew GL4Z	Arzew	1.1	1.5	Existing	1964
	Arzew GL1Z (Bethouia)	Arzew	8.2	11.2	Existing	1978
	Arzew GL2Z (Bethouia)	Arzew	8.0	10.9	Existing	1981
	El Andalus LNG (Gassi Touil)	Arzew	4.0	5.4	Engineering	2009
	Skikda	Skikda	4.5	6.1	Engineering	2010
Nigeria	NLNG 1-2	Bonny Island	6.6	9.0	Existing	1999
	NLNG Trains 3	Bonny Island	3.3	4.5	Existing	2002
	NLNG Plus T4-5	Bonny Island	8.2	11.2	Existing	2006
	NLNG Train 6	Bonny Island	4.1	5.6	Under construction	2007
	NLNG Seven Plus T7	Bonny Island	8.0	10.9	Engineering	2011
	Brass LNG	Baylesa	10.0	13.6	Engineering	2011
	Olokola LNG (OK LNG)	Olokola	11.0	15.0	Engineering	2011
Equatorial Guinea	EG LNG	Bioko Island	3.4	4.6	Under construction	2007
	EG LNG 2	Bioko Island	4.4	6.0	Planned	2012
Angola	Angola LNG	Soyo	5.0	6.8	Planned	2011
Norway	Snøhvit	Melkoya Island	4.1	5.6	Under construction	2007
Russia	Baltic LNG	Ust-Luga	5.3	7.2	Planned	2010

Table 43 LNG liquefaction plants (cont.)

Region/Country	Project	Location	Capacity (mtpa)	Capacity (bcm per year)	Status	Start
	Shtokman LNG	Murmansk	15.0	20.4	Planned	2015
Trinidad	Atlantic LNG 1	Point Fortin	3.3	4.5	Existing	1999
	Atlantic LNG T2/3	Point Fortin	6.6	9.0	Existing	2002
	Atlantic LNG T4	Point Fortin	5.2	7.1	Existing	2005
	Train 5		5.2	7.1	Planned	2010
Venezuela	Plataforma Deltana		4.7	6.4	Planned	2010+
Total			**420.3**	**571.8**		
Total existing			**189.7**	**258.1**		

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