NATURAL GAS MARKET REVIEW

2008

Optimising investments and ensuring security in a high-priced environment

INTERNATIONAL ENERGY AGENCY

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Over the last 18 months, natural gas prices have continued to rise steadily in all IEA markets. What are the causes of this steady upward trend?

Unprecedented oil and coal prices which have encouraged power generators to switch to gas, together with tight supplies, demand for gas in new markets and delayed investments all played a role. Investment uncertainties, cost increases and delays remain major concerns in most gas markets and are continuing to constitute a threat to long-term security of supply.

A massive expansion in LNG production is expected in the short term to 2012, but the lag in LNG investment beyond 2012 is a concern for all gas users in both IEA and non-IEA markets. Despite this tight market context, regional markets continue on their way to globalisation. This tendency seems irreversible, and it impacts even the most independent markets. Price linkages and other interactions between markets are becoming more pronounced.

The *Natural Gas Market Review 2008* addresses these major developments, and places a large emphasis on investment in natural gas projects (LNG, pipelines, upstream), escalating costs, the activities of international oil and gas companies, and gas demand in the power sector. In addition, the publication includes data and forecasts on OECD and non-OECD regions to 2015 and in-depth reviews of five OECD countries and regions including the European Union.

It also provides analysis on 34 non-OECD countries in South America, the Middle East, Africa, and Asia, including a detailed assessment of the outlook for gas in Russia, as well as insights on new technologies to deliver gas to markets.

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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-seven 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 promote international collaboration on energy technology.
- 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, Slovak Republic, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States. Poland is expected to become a member in 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.

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FOREWORD

2007 and 2008 have been tumultuous years for the energy sector; natural gas markets have not been immune from the strong fundamental forces driving other energy sources. Strong upward trends in price levels and continued demand growth have marked natural gas markets, while regional market events were increasingly interlinked through LNG trade on a global scale. Tight supply, rising oil prices, and a lack of transparency in many gas markets fostered security of supply concerns, while ongoing investment project delays and rising costs fuelled discomfort for long-term market prospects.

However, improved hub trading in Europe, a strong market response by gas producers in North America to rising prices, and the advance in a number of big supply projects represent positive developments in the evolution of gas markets in IEA member countries during the past year.

The present annual review, the third of its type, analyses these global trends, highlighting recent price developments, and analysing the continuing shift towards globalisation of gas markets. A prospective on future demand and supply balance for OECD markets provides insight into the expected regional market evolution to 2015.

Adequate investment in supply infrastructure is a major issue for long-term security for both consumers and producers. Hence, investment is given a special focus in this review. A detailed analysis is provided on transport infrastructure projects, LNG and pipelines, as well as on significant non-OECD markets and producing regions. The evolution of five OECD markets is also featured in individual in-depth surveys.

The review analyses other important topics such as new technologies to bring gas to markets, existing security of supply mechanisms on country levels, and gas-to-power utilisation. A comprehensive register of LNG infrastructure and financing is also provided.

Globalising gas trade may raise questions on security of supply mechanisms and long-term sustainability of markets. However, enhanced transparency in data and forecasts, and level-playing field competition between markets can bring security, flexibility and efficiency for all stakeholders in the gas industry.

Gas remains a key fuel in meeting growing energy demand, especially in power markets, and with its lower carbon footprint, an important contributor to climate change goals. But while mid-2008 has seen some easing of gas prices in a number of key markets, overall markets remain tight, and prices are still high relative to those of past years.

As for previous editions, we welcome feedback on the review.

This book is published under my authority as Executive Director of the International Energy Agency.

Nobuo Tanaka

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KEY MESSAGES

1 Gas prices in all regional markets continued to rise in 2007 and in the first half of 2008 due to a number of factors including higher oil prices, unseasonal weather conditions and supply and demand imbalances.

2 Demand growth was strong in 2007 at around 4.5% in the OECD, compared with overall energy supply growth of 1%. Strong growth has continued into 2008 particularly in non-OECD countries.

3 In the short to medium-term, LNG trade will play a stronger role in all OECD regional markets. In Europe, imports will constitute more than half of total supplies, with LNG expected to reach nearly 20%. In OECD North America, indigenous production will continue to supply more than 90% of expected demand by 2015 yet LNG imports are expected to be more than double 2007 levels. LNG is already pivotal in OECD Pacific.

4 Gas demand for power is growing, particularly in the IEA but also in a number of major producing and consuming non-OECD countries. Gas-fired power has dominated supply growth in IEA countries since 2000; this looks set to continue, notwithstanding strong growth in renewables. In several countries, particularly in Europe, decisions need to be taken in relation to the future of ageing coal and nuclear power plants, which in turn may impact the demand for gas-fired power.

5 Investment uncertainties, cost increases and delays remain a major issue in most gas markets and are continuing to constitute a threat to long-term security of supply. The escalation of engineering, procurement and construction (EPC) costs, the tight engineering market and risks in producing countries were amongst the main causes for investment project delays.

6 Gas markets are on their way to globalisation. Flexible LNG (spot and short-term) played a greater role in inter-regional market balancing in 2007. In the present tight market context, this market integration seems to be aligning prices in some regions at higher levels. More transparency on prices and flows and more competitive internal markets could bring beneficial effects from inter-regional competition in the long term, as well as improving gas security.

7 Domestic markets of many major producing countries are now consuming more gas than before and new energy policies underline the priority of local demand. In the medium- to long-term, progressively rising domestic prices in these markets might provide economic incentives to develop resources and use gas more efficiently. In the absence of price reform, these developments will not occur.

***8** Liquidity on European hubs, both on the United Kingdom's National Balancing Point (NBP) and on most European continental hubs, has grown considerably. Such liquidity promotes more flexible market responses, more transparency and more accurate price signals.*

***9** Gas security needs to be addressed through appropriate policy measures and market mechanisms, at a level that recognises potential impacts of supply disruptions and global market interactions.*

***10** Market players are trying to find new ways to overcome the high cost of gas transport, as well as reach and exploit new reserves which may become viable under present market conditions. Therefore, increased R&D in new technologies to deliver gas to markets is needed.*

EXECUTIVE SUMMARY

2007: Demand and prices continue to rise

Over 2007 and into the first half of 2008, natural gas prices continued to rise in all IEA markets. Tight supplies, unprecedented oil prices, demand growth in established as well as new markets, and delayed investment were amongst the causes of this steady upward trend. While the weakening United States dollar cushioned these price increases somewhat in 2007, at least in euro and yen terms, continuing upward pressure in 2008 is translating into further significant price rises everywhere. Price levels, however, still vary between markets as a result of particular regional and national characteristics, despite the increasing mobility of LNG cargoes.

Rising prices have not curbed demand in consuming markets – in the United States, gas demand grew by 6.5% in 2007, with growth continuing into the first quarter of 2008 at around 4%, on the back of a cold winter. In Japan, growth in 2007 was 9%, continuing into 2008, as nuclear plant utilisation fell below 50%, and higher LNG imports helped fill the gap. In Europe, the pattern of previous warm winters continued, thus dampening growth in gas consumption. Despite this Turkey continued its strong growth, up 17% on 2006; gas use has doubled to 37 bcm since 2002. A return to more normal weather patterns in Europe in the early part of 2008 saw growth of over 8% in the first quarter of the year, most notably in Spain where demand increased 20% in the six months to April 2008.

Gas markets in a globalising context

Regional gas markets are on their way to globalisation. This trend seems irreversible, and impacts even the remotest and the most independent markets, at least marginally. More producing and consuming countries, growing dependence on external imports in OECD Europe, tighter balances, increasing volumes of spot and short-term LNG, and higher prices encourage global interactions. In the tight market context of 2007 and the beginning of 2008, spot and short-term LNG trade played a greater role in inter-regional market balancing, aligning prices for some regions at higher levels. In order to benefit from this globalising trend, more transparency on prices and flows, and more competitive internal markets are needed. Interregional competition will then improve global gas security in the long term.

Gas supply developments

On the OECD supply side, indigenous gas production in the United States appears to have responded significantly to higher prices, especially in late 2007 and 2008 while United Kingdom production continued its dramatic fall of nearly 10% per year.

Russia, OECD Europe's main source of gas imports, maintained production in 2007 at 2006 levels despite the continuing depletion of its traditional major producing fields. Independent producers also maintained production levels close to 2006 output. In June 2007, the Russian government passed an amendment to existing regulations intending to align domestic gas prices to net-back export prices by 2011. Coupled with a programme to reduce gas flaring and increase efficiency in gas use, this set of reforms is intended to free up more gas volumes to meet rising domestic demand and export requirements. However, in the context of inflationary pressures, price reform could be postponed.

In other exporting countries, LNG production capacity is set to grow rapidly, although not as quickly as anticipated in the past. Commissioning and production problems are appearing in new LNG liquefaction plants, delaying commercial deliveries of cargoes and causing concerns among consumers.

There was positive news in LNG supply with Equatorial Guinea and Norway joining the ranks of LNG exporters. Despite this, there has been a distinct lack of final investment decisions (FIDs) over the period since the 2007 Natural Gas Market Review. Positive announcements have come only from Angola, Australia and Algeria.

Delays and cancellations were a frequent feature of upstream gas development in 2007 and 2008, due notably to escalating engineering, procurement and construction costs. Moreover, in some producing countries, growing state involvement in the control of energy resources and their development continues to influence decision making. Tensions concerning the allocation of resources between the domestic market and exports persist in Indonesia, Nigeria and in the Middle East and North Africa. Low domestic gas prices in many of these countries are leading to greater volumes of gas being consumed locally, often at greatly distorted prices, in efforts to diversify and strengthen the economy, in industries such as petrochemicals, water desalination and power generation. Low domestic prices also discourage upstream investment.

Similarly, domestic politics and economic development policies in some producing states hinder the necessary investment and technical know-how to capitalise on their resources. Government intervention and state appropriation of privately owned assets, coupled with complex financial arrangements, ensure that much of the gas reserves remain in the ground.

Investment in import infrastructure

An unprecedented major expansion is underway globally in regasification capacities, well in excess of LNG production capacity. Consequently, regasification capacity is likely to be underutilised relative to liquefaction but this likely excess capacity could be a source of flexibility. "Global" exchange of LNG cargoes is accelerating, particularly from the Atlantic to the Pacific region, facilitated by the changing business models of the LNG industry.

Pipeline infrastructure development in 2007 was marked by delays and increased costs of major projects; both the Nabucco and Nord Stream projects saw cost estimates increase by at least 50%. In North America, the Alaska pipeline was delayed, although the Rex Pipeline project is on time. In marked contrast to North American pipeline investment, investment in internal interconnections and in new supply projects in Europe continues to lag.

In LNG similar trends can be seen, with a significant amount of capacity being planned but not all projects actually proceeding. Major delays afflict many projects with some cancellations such as the Baltic LNG project announcement from Gazprom. The dearth of FID in new LNG projects since mid-2005 means that any major post-2012 expansion of capacity is more likely to slip toward 2015. Notwithstanding the massive expansion in LNG that will occur in the decade 2002 to 2012, the lag in LNG investment beyond 2012 is a concern for all gas users in both IEA and non-IEA markets.

Gas to power

Despite rising gas prices, gas-fired power exerts a major influence on demand for gas in both OECD and non-OECD countries. There was little in the way of new coal plant built outside of the developing world in 2007 and less than a handful of announcements in relation to new nuclear plant. In OECD countries, especially in Europe, low capital costs, short lead-times, and relatively light environmental footprints still make CCGT the low risk default option for new investments in power generation in an environment characterised by considerable regulatory uncertainty. In a number of oil and gas producing countries, namely in the Middle East and North Africa region, gas is emerging as the fuel of choice to meet rising electricity demand. In the major emerging economies of China and India the share of gas in the generation mix remains relatively small, but the volumes consumed can be significant in terms of global gas use and trade.

Gas security

While much of 2007 was crisis-free relative to other years, events in the first half of 2008 have served to remind us of the fragility of gas markets. In June 2008, an explosion at a gas supply hub in Western Australia reduced local gas supplies by 30% with significant implications. Earlier in 2008, a minor dispute between Turkmenistan and Iran resulted in gas shortfalls in Iran, holder of the world's third largest gas reserves. This incident had repercussions as far away as Greece and Turkey.

Role of new technology

Advances in technology to access new gas resources and find new ways of bringing gas to markets are essential to ensure additional supplies for a growing demand. Delivering greater efficiency in upstream and downstream sectors is a key objective of research and development to ensure gas market sustainability over the long-term. In a globalising gas market – one with rising prices, tight supply prospects and increasing environmental constraints – frontier gas resources will probably see their contribution to global gas supply grow in the future.

RECENT EVENTS

What's driving prices?

Gas prices in 2007 and 2008

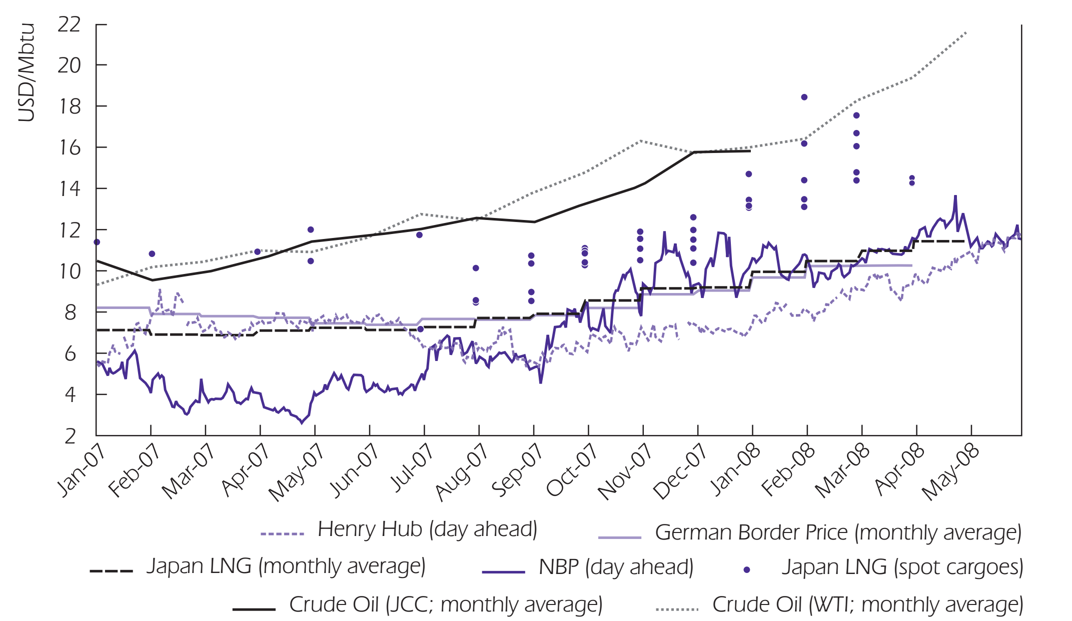
The global trend of rising gas prices continued in 2007 and into the first half of 2008. Driving these price rises were high oil price levels, cold weather and strong demand particularly from power generation in OECD and producer countries.

While the fall in the United States dollar relative to the euro and yen has softened the impact of price increases in some regions, all markets have continued to see significant real price increases in 2008, most notably in North America.

Europe

Despite the growth of competitive gas trading at hubs in continental Europe (see separate section), where price is determined solely by the forces of supply and demand, the linkage to oil prices remains strong on the continent while in the United Kingdom gas-to-gas competition prevails. The NBP day-ahead prices reflect regional gas prices in the United Kingdom and the German Border Price is an indicator of the oil-based gas price on the European continent. During 2007 and the first half of 2008, the German Border Price rose because of its direct (albeit lagged) link to oil prices. High oil prices up to mid-2008 will ensure an increasing German Border Price for much of the rest of 2008.

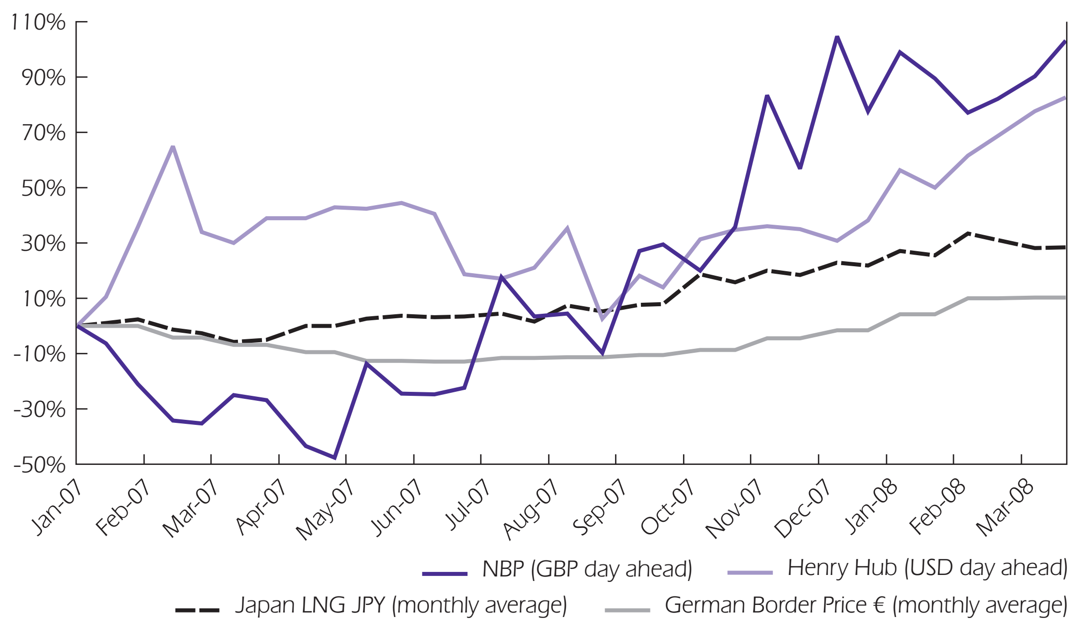
Figure 1 Gas prices in 2007 and 2008



Source: Monatliche Erdgasbilanz und Entwicklung der Grenzübergangspreise ab 1991: März 2008, Heren, ICE, Japan custom clearance data from 1969 to March 2008, Platts.

Note: The average Japan LNG price includes all LNG, including long-term, short-term, and spot cargoes.

Figure 2 **Gas prices and the value of United States dollar**



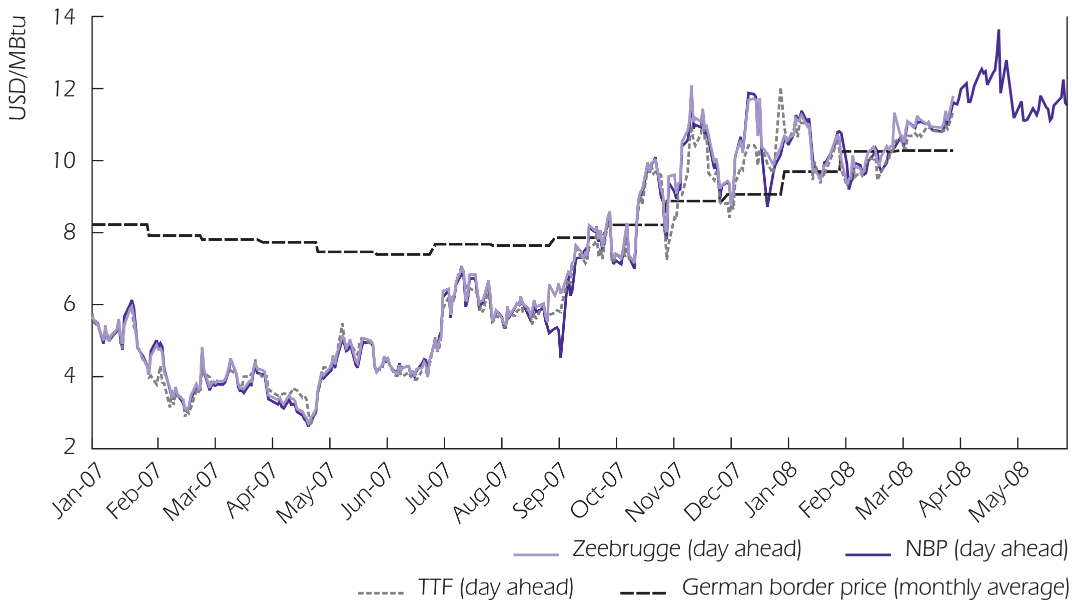
Source: Monatliche Erdgasbilanz und Entwicklung der Grenzübergangspreise ab 1991: März 2008, Heren, ICE, Japan custom clearance data from 1969 to March 2008.
Note: The average Japan LNG price includes all LNG, including long-term, short-term, and spot cargoes.

Prices in the United Kingdom remained relatively low during the first quarter of 2007 due to an upturn in import capacity and somewhat mild weather. Since April 2007, there has been a reversal of the downward trend in gas prices due to unpredictability of Norwegian supply. For example, in the first half of May 2007 flows to Britain through Langeled were only around half of April's 2007 average. During late May and early June 2007, imports dropped again because of planned maintenance work in the Oseberg and Grane areas of the North Sea. Higher NBP prices during the second half of 2007 were due to a number of factors, including technical and operational problems; notably South Morecambe maintenance, Shell's Goldeneye platform unexpected shut down, late start-up of the Tampen link in Norway, the annual planned maintenance of the Interconnector and the Rough storage site, and the BP Bruce and Rhum fields' problems. In addition, high prices paid for LNG cargoes by Asian buyers have affected NBP prices as the United Kingdom is increasingly dependent on imports. Prices on the continental hubs TTF (the Netherlands) and Zeebrugge (Belgium) closely track those of the NBP.

North America

Natural gas can be traded or priced at almost any location in North America: there are 38 different hubs in the United States and nine in Canada. The prices set at Henry Hub on the Texas/Louisiana border are considered to be the primary price quotation for the North American gas market. Prices on the Henry

Figure 3 **European gas prices 2007 and 2008**



Source: Monatliche Erdgasbilanz und Entwicklung der Grenzübergangspreise ab 1991: März 2008, Heren.

Hub spiked in first quarter of 2007. After this, trading remained stable in the USD 7 - USD 8 per Mbtu range. In autumn 2007, prices decreased below USD 6 per Mbtu despite a sharp increase in gas-fired power: gas use in the power sector went up 11% in 2007, making gas the number two source of electricity. In 2008, prices increased from USD 7 per Mbtu to more than USD 13 per Mbtu in June 2008 due to increases in oil prices, continuing cold weather in the first quarter of 2008, lower inventories and increased demand.

Asian LNG

In traditional long-term Asian LNG contracts, pricing is linked to the import prices of a basket of Japan crude oil prices (Japanese Crude Cocktail or JCC). However, the link to oil prices (especially at current oil price levels) is less than 90% on average, resulting in LNG prices lower than oil prices on heating value basis. Although only a small part of LNG is traded on a true spot basis, the prices paid for spot cargoes tend to reflect the current market situation. The share of LNG traded this way grew in 2007 and Asian LNG prices for spot cargoes rocketed in 2008 because of high oil prices, Japanese economic activity and increasing demand as a result of cold winters and nuclear power plant problems in Japan. Reflecting a tight supply/demand balance, prices for cargoes were high with Japan paying top prices for February 2008 cargoes of LNG. Korea and China also paid high spot prices to be able to meet seasonal winter demand in 2007.

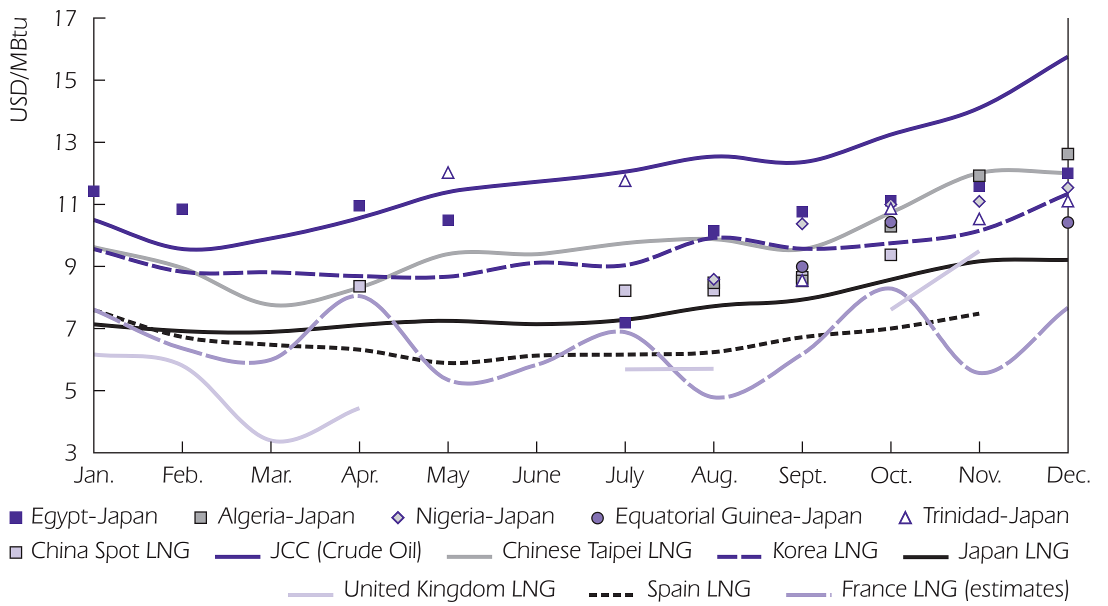
Worldwide prices and market responses

Higher prices have tended to lead to higher production in, for example, the United

States. During 2007, indigenous production in the United States was up 4.3% on 2006 levels reaching 550 bcm, an increase of 23 bcm on the previous year. This was the highest level of production recorded since 2000. The production increase was most marked at the end of 2007 and has continued into 2008. During the first quarter of 2008, production was up 9% on Q1 2007 levels, representing a notable response to higher prices. Much of the new gas comes from non conventional technologies that are viable at this price level, for example gas from shale in the Barnett Shale area in east Texas, coalbed methane gas and deep water gas in the Gulf of Mexico. If this trend continues it will be a sharp change to the production position for the United States.

Changing price relativities between markets are also an important driver of spot and short-term LNG sales, even more so than in 2005-2006. As figure 6 illustrates, spot gas prices in the United Kingdom were only around half of the pricing level in North America in the first months of 2007. As a result, the United States was a more attractive market for LNG. Hence, United States imports were high over the period from March to August 2007; over the year LNG imports reached a record level equivalent to 22 bcm of natural gas, 31% higher than the previous year. LNG imports collapsed in the final third of the year, as supplies were tight, while demand from Asia, but also Turkey and Spain, was strong. Hence, cargoes moved long distances in response to strong demand and subsequent high prices. By December the United States had the lowest LNG imports

Figure 4 **Global LNG prices in 2007**



Source: Customs statistics from governments, IEA, Eurostat.
Note: dots represent prices of individual spot cargoes while lines reflect the average LNG price. For comparative purposes some European LNG prices have been added.

for any month since 2002. Such behaviour represents a significant change in global LNG marketing.

As long as short-term gas demand continues to fluctuate in various regional markets, some portion of flexible LNG supply is expected to move around the world depending on regional demand and price developments.

Is gas globalising and what do we mean by this?

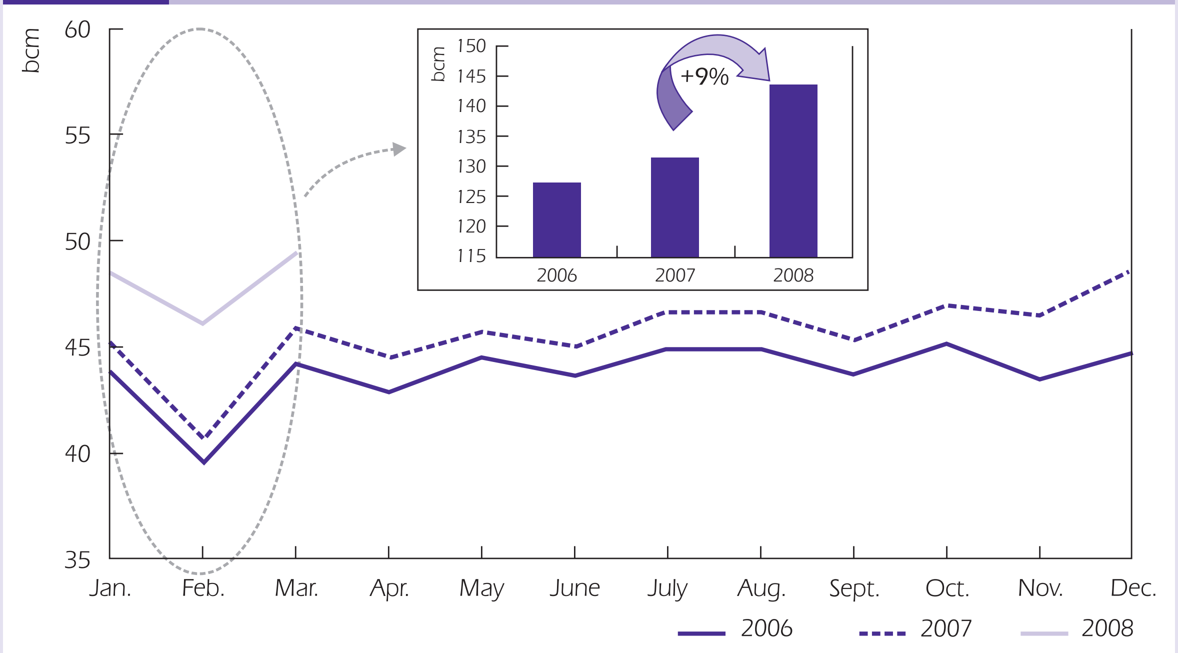
Globalisation of natural gas markets

There are a number of different views on the globalisation of natural gas markets. Some argue that gas markets continue to be regional. It may be true that distinct ways of gas pricing will remain and regional (and long-term) transactions will continue to constitute the backbone of the business. Resource endowment, availability of alternative energy sources and geopolitical issues are peculiar to each region as well. However, more producing and consuming countries, increasing dependence on imports in OECD countries, tighter balances, increasing volumes of spot and short-term LNG, and higher prices encourage global interactions.

Discussions in the industry on "globalisation"

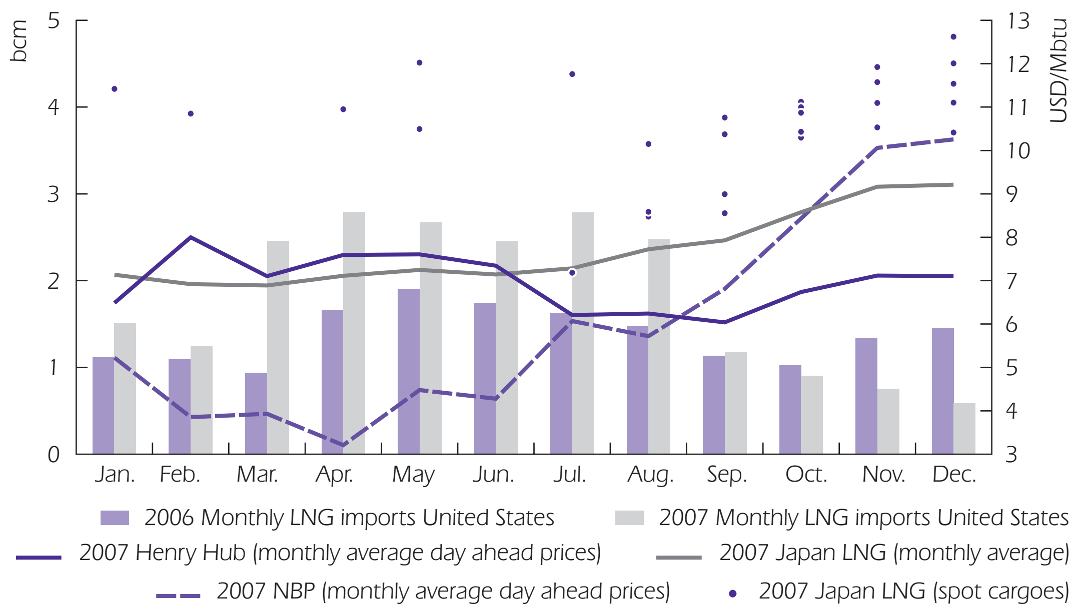
During the past few years, "globalisation" of the gas industry has been discussed extensively often considering trends in globally integrated pricing and free

Figure 5 United States production 2006 to 2008



Source: EIA.

Figure 6 **Worldwide prices and United States LNG imports**



Source: Heren, ICE, EIA/DOE, Japan custom clearance data from 1969 to March 2008.

movements of LNG cargoes. While LNG and gas are more globalised today than yesterday and will be more so in the near future, many industry observers believe that they still have a long way to reach a level of total "globalisation", comparable to oil markets.

Again, industry observers argue that gas is still a regional fuel, although international gas markets are more connected with each other than they have ever been before. One reason for this is that LNG sales represent only 7% of global gas sales (susceptible to the sort of diversions discussed in the previous section), compared to 15% for seaborne coal and 48% for seaborne oil. Another reason is that while LNG is clearly becoming more of a global commodity, and increased price influence and communication between markets have been seen, it is highly unlikely, in the near term at least, that the industry will see the emergence of a single global spot price for gas or LNG.

The primary reason for fluctuating LNG volumes into the United States and United Kingdom is the emergence of the "secondary LNG market" or diversion. In this case buyers have remarketed their cargoes to other importers, rather than sell through a global spot LNG market (as would be the case with oil).

While the emergence of an LNG portfolio approach facilitates some global movements of cargoes, sellers do not necessarily favour a single global commodity price. The portfolio approach is being developed at the same time by producers, NOCs (national oil companies) and IOCs (international oil companies) alike as well as by traditional

Table 1 **Share of trade and LNG in world gas consumption**

	1971	1990	2000	2006	2015*
World Gas Consumption (bcm)	1 100	2 072	2 528	2 936	3 689
World Gas Trade (bcm)	60	535	644	868	(641)*
World LNG Trade (bcm)	4	74	140	215	393
Share of Trade in Consumption	5.5%	25.8%	25.5%	29.6%	n.a.
Share of LNG in Consumption	0.3%	3.6%	5.5%	7.3%	10.6%
Share of LNG in Trade	6.2%	13.8%	21.7%	24.8%	n.a.

Source: World Energy Outlook 2007, IEA.
*The figures only include inter-regional trades; intra-regional trades, such as that between Canada and the United States are not included in the figure for 2015.

Table 2 **The changing world of LNG**

	2000	2006	2010 (projection)
Volume (bcm)	140	215	300-320
Middle East's share	17%	24%	30%-35%
Biggest exporter	Indonesia (26%)	Qatar (15%)	Qatar (25%-30%)
Japan's share	54%	41%	25%
Players (country, region)	12 exporters/ 11 importers	13 exporters/ 16 importers	18 exporters/ 22 importers

LNG buyers who have contracted long-term volumes beyond their market requirements. This is probably another indication that the market will remain primarily a long-term contract business with short-term imbalances.

There has been considerable interest in the LNG industry in how much the spot LNG market will grow in the future. According to the GIIGNL (LNG importers' group) "spot and short-term" imports represented 13% of trade in 2005 and 16% in 2006 rising to 20% in 2007 (these figures include short-term volumes *i.e.* those with duration of less than four years).

Regional and long-term trades with destination restrictions (physically in the case of pipeline gas and contractually in the case of LNG) will continue to be the mainstream of the gas industry. Gas is unlikely to be a completely freely traded commodity, as oil is, at least in the medium term.

On the other hand, (long-distance) inter-regional trades and import dependence are growing significantly. Increasing flexibility in trades and multiple routes and modes of transportation enable wider exchanges of gas. LNG portfolio and secondary marketing strategies are

Table 3 **Features of traditional and globalising gas markets**

Traditional features	Globalising gas markets
Regional, long-term trades, destination restrictions (Gas cannot be a completely freely traded commodity as oil is)	Inter-regional trades and import dependence; increasing flexibility in trades, multiple routes and modes of transportation; LNG portfolio marketing, increasing shorter-term transactions at the unloading end
Marginal, supplemental nature of gas, compared to other energy sources	Gas as a fuel of choice, technological advance, rising prices resulting in longer-distance transportation at cheaper cost compared to market prices
Companies act locally	Companies act globally. "National" companies (Qatar Petroleum, Gazprom, Petronas, and Sonatrach) play "internationally" and utility companies go abroad

increasing shorter-term transactions at the unloading end of the chain, as noted above. For example, those companies which secure long-term LNG supply at the loading end with destination flexibility often sell cargoes to different buyers under shorter-term and secondary sales agreements. Thus pricing interactions between widely separate gas markets are increasing: for example, buyers of LNG cargoes diverted from the Atlantic region must now pay at least Henry Hub prices (on a net-back basis), thus setting an effective floor for such spot LNG trade.

Gas used to be a marginal and supplemental source, compared to other energy sources in the past. Gas has now become a fuel of choice, especially in OECD countries and in gas producing nations. This situation has been helped by technological advances, resulting in longer-distance transportation at cheaper cost relative to market prices. As customers from different global regions can now buy gas from the same supply sources, customers can both compete against each other and cooperate with each other. Gas development projects that otherwise would be impossible can now be developed. To illustrate the latter point, the Sakhalin, Yemen and Tangguh LNG projects were unable to get the green light until they acquired customers in both eastern and western markets.

Major investment project decisions, commitments and approvals

Timely and accurate investments all along the gas supply chain are important for the efficient and secure functioning of markets. Since the last Natural Gas Market Review, few decisions have been made on investment in major gas supply projects. For example, the rate of expansion of LNG capacity represented by final investment decisions in the last year is less than half of recent historic levels, while at the same time some major projects have seen changes in their project structures. A global trend of project delays can be observed. Several major pipelines and LNG regasification or liquefaction projects in negotiation for a number of years have not yet received important regulatory approvals or financial commitments. Such delays are potentially harmful for security of supply in the long term.

Final investment decisions on LNG exports and receiving terminal projects are described in greater detail in the LNG section: Australia's Pluto, Algeria's Skikda replacement, Angola LNG (also discussed in the West Africa section), and Rotterdam Gate LNG in the Netherlands. Project restructurings are also considered in the LNG Chapter including Shtokman in Russia and Gassi Touil in Algeria. In the Investment in new supply projects chapter, a detailed analysis of major pipeline projects in North America and Europe is presented.

Table 4 Major project decisions in 2007 and early 2008 - at a glance

Project	What has happened	Factors	Implications
Shtokman, Russia	Participation by Total and StatoilHydro in the Shtokman first development phase. Baltic LNG was cancelled presumably to focus on Shtokman.	Development could be difficult without expertise from major international oil and gas companies. Total is accumulating LNG project experiences particularly with its success in Yemen.	Shtokman advanced to a front-end engineering and design (FEED) phase in March 2008. Development is still difficult, requiring major and long-term market commitment before FID.
Gassi Touil, Algeria	Sonatrach cancelled the development agreement with Repsol and Gas Natural (GN) of Spain.	The original 2009 production target had become unlikely.	Sonatrach is negotiating with EPC contractors to build the LNG plant.
Skikda replacement train, Algeria	Sonatrach awarded construction (EPC) contract to Kellogg Brown & Root (KBR).	As Algeria's exports have declined for some time, Sonatrach wants to spearhead development.	The project should help achieve Algeria's exports goal by 2012, later than the original 2010.
Pluto, Australia	Final investment decision and Japanese buyers' equity participation in the project.	Woodside has wanted to gain momentum to become Australia's champion LNG company by speedy development of Pluto.	An advantageous position as the first additional supply source in the 2010s in the Pacific region, as well as potentially aggregating the area's gas resources as an LNG hub.
Angola LNG, Angola	Final investment decision, following partner changes.	An integrated approach including downstream marketing in the United States. The country's need to monetise associated and non-associated gas resources for both export and domestic markets.	Further diversification of West Africa's LNG supply sources, following Nigeria and Equatorial Guinea.
Gate LNG, Rotterdam, Netherlands	Final investment decision	Partners want to establish a position as the first LNG receiving terminal in northwest Europe, even without firmly committed long-term supply sources.	The project would represent the first LNG receiving terminal in a major gas producing country in continental Europe.

Source: IEA analysis, company information, media reports.

Table 5 **Infrastructure utilisation in IEA Europe and new EU member states**

	2006				2015			
	existing capacity	utilised capacity	average utilisation rate	**total average utilisation rate**	planned additional capacity	existing and planned capacity	projected utilisation	**total average utilisation rate**
LNG	104	56	54%	72%	184	288	437	51%
Pipeline	374	290	78%		195	569		

Source: IEA, GIE, company information.
Note: Pipeline capacity includes pipelines to IEA Europe + new EU member states. SCP and Langeled included in planned capacity.

In contrast with the increasing delays in FID and regulatory approvals, the actual number of projects has increased substantially, with many supply infrastructure projects (LNG terminals, pipelines) being in competition for the same markets, and often for the same sources and routes, particularly in Europe. This presents the possible risk of under-utilisation of some assets in the future.

Trading developments in Western Europe

Over recent years, liquidity on European hubs, both on the United Kingdom's National Balancing Point (NBP) and on most European continental hubs, has grown considerably.[1] The development of liquid European hubs is important because it facilitates achievement of a competitive European gas market and contributes to making gas a true commodity. In continental Europe, trade has continued to grow since 2003, and during 2006 and 2007, continental hubs experienced a significant increase in liquidity especially when compared with the NBP.

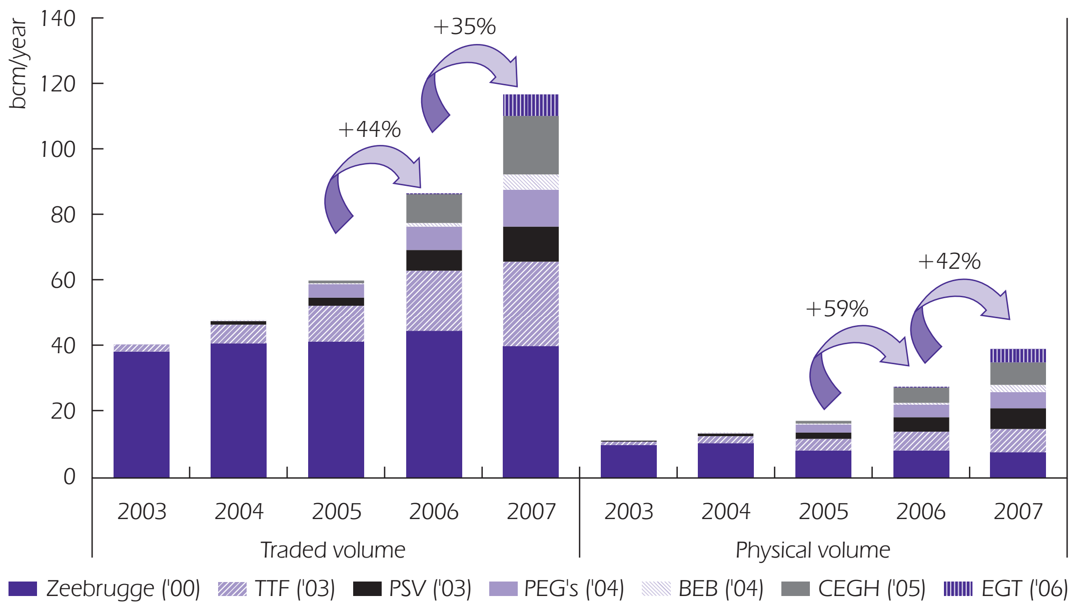
Total traded volume on the significant[2] continental hubs in 2007 equalled 117 bcm and 40 bcm of physical volumes, up 35% and 42% respectively on 2006.[3] However, when compared to the NBP (2007: 903 bcm traded volume and 67 bcm physical volume), volumes still remain small. Also, the average 2007 churn ratio on the NBP (13.5) was much higher than the average continental churn ratio of 3.[4]

United Kingdom

The United Kingdom's NBP is Europe's most liquid trading point. Despite the

1. This section is partly based on the information paper "Development of Competitive Gas Trading in Continental Europe", IEA, May 2008.
2. BEB, CEGH, EGT, PEG's, PSV, TTF and Zeebrugge.(See text for explanation).
3. The physical volume (often also the physical throughput) is the amount of gas delivered through the hub. Because gas can be traded more often before final delivery, the traded volume can be significantly higher than the physical volume. The churn ratio represents the amount of times gas is being traded before it is delivered. The traded volume divided by the physical volume equals the churn ratio. In case of PSV, CEGH and BEB only the physical volumes for the last years were given, while for PEG's no physical volumes were given. The missing physical volumes had to be estimated.
4. Volume weighted average over all continental hubs. Some of the churn ratios were based on an assessment.

Figure 7 ***Traded and physical volumes in continental Europe***[4]



Source: data published by TSOs.

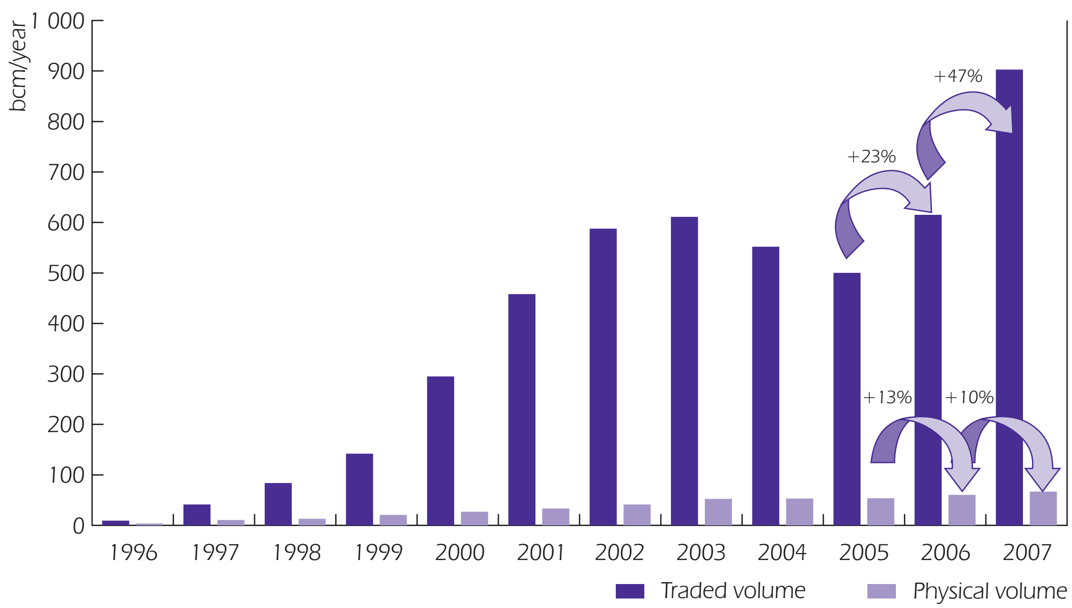
development of the continental European hubs, expectations are the NBP will remain the most significant hub for the coming years. After the collapse of Enron in 2002, traded volume at the NBP decreased as credit limits were tightened and American players exited the market. However, the downward trend turned in 2006 and in 2007 the traded volume was at its highest recorded level, at 900 bcm, up 47% on 2006.

Belgium

Zeebrugge has been the exception to the above rule of growing continental hubs, as traded volumes fell by 11% in 2007 and physical volumes by 7%. The Zeebrugge hub, which in 2003 was the only significant continental European hub, has had a hard time dealing with increased liquidity on other continental hubs, particularly the Dutch TTF. Indeed, many continental traders have questioned the need for two significant gas hubs in such close proximity to each other and have suggested that they be merged into one.

One of the reasons for the decline in Zeebrugge is that the major high-pressure pipeline systems running through Belgium to Germany, Netherlands and France are practically unavailable to third-party access due to their historic role as "transit" pipelines. This was evident during the cold winter of 2005-2006 when many companies were unable to flow gas to Zeebrugge and make use of price arbitrage with other hubs.

Figure 8 **Traded and physical NBP volumes**



Source: data published by TSOs.

From February 2008, the company managing the hub, Huberator (fully owned by the Belgian TSO Fluxys) is offering unlimited capacity transfers in the Zeebrugge area which enables shippers to transfer gas between all entry points (Interconnector terminal, Zeepipe terminal, LNG terminal and the Zeebrugge hub) without capacity limitations. Expectations are this will increase liquidity.

The Netherlands

TTF (Title Transfer Facility) has witnessed an increase in liquidity over the last two years and prices here closely track those of the NBP following the arrival of the BBL pipeline connecting the United Kingdom and the Netherlands in December 2006 (see figure 9). TTF has been considered the most active continental European market for some time, and in January 2008 it surpassed Zeebrugge on traded volume for the first time. Traded and physical delivered volumes in January 2008 were double the figures for January 2007. In addition TTF has the most active European forward market, with different financial players, in which gas is traded for up to several years into the future.

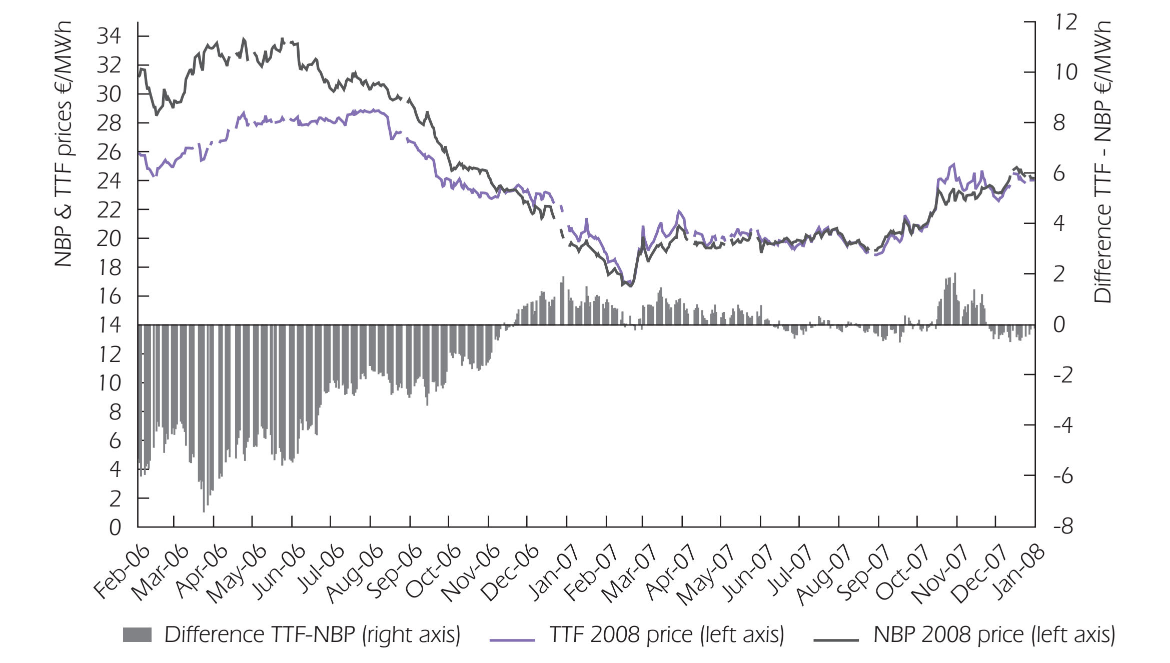
It is reasonable to assume that the emergence of TTF implies TTF prices will be considered as the benchmark price in the Netherlands in the near future. Preliminary results of a recent survey among industrial gas users in the Netherlands indicated that 70% of industrial users questioned compare oil-based prices with the prices charged at TTF on a daily basis. When oil-indexed gas prices are significantly above TTF prices, it becomes more attractive for market participants to buy their gas at TTF prices. During 2007, such a price differential in favour of TTF existed for year-ahead products for several months in succession. As a result, there has been substantial pressure on gas companies to alter their domestic oil-based pricing strategy in order to become competitive.[5]

In reaction to this market pressure, Dutch gas company GasTerra added a new pricing product to its domestic product portfolio in June 2007. GasTerra now offers gas at a gas-indexed price, based on TTF month-ahead prices. Argus Media Ltd. and Heren Energy monthly indices are taken as the basis for the indexation, as the market deems these indices as transparent, public and respected. GasTerra anticipates selling approximately 10% of its domestic sales volume at TTF indexed prices in 2007 for 2008; sales figures at the end of 2007 showed GasTerra's estimations were reasonably accurate. GasTerra has announced they are considering whether they can extend the product range further during 2008.

Germany

The German transportation market is divided between several transport operators each developing different hubs. Of particular interest are the virtual markets operated by E.ON GasTransport (EGT) and the hub established by BEB in North-West Germany,

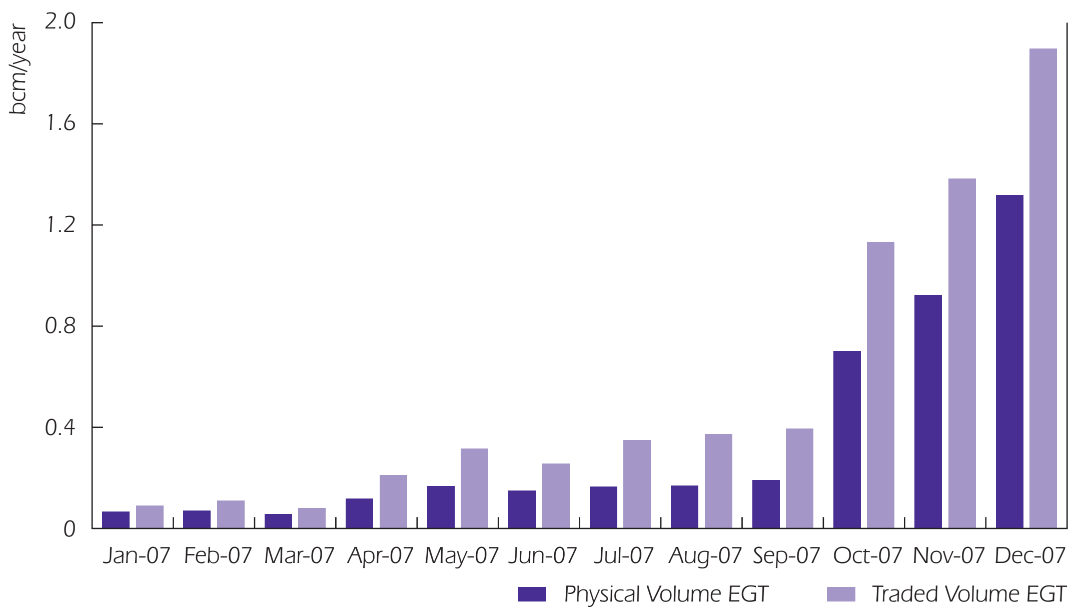
Figure 9 **TTF prices and NBP prices before and after arrival of BBL interconnector**



Source: Heren.
Note: BBL pipeline commisioned in December 2006.

5. It is not surprising this pressure did not exist during 2006, when the level of year-ahead oil-indexed gas prices did not exceed the level of year-ahead TTF-prices.

Figure 10 **Traded and physical volumes at EGT in 2007**



Source: data published by TSOs.

the BEB VP. The physically delivered volume on virtual markets in Germany increased rapidly in 2007 from 0.7 bcm in 2006 to 6.2 bcm. The main reason for this growth was the implementation of the new entry-exit network model on 1 October 2007. As of that date, the Bundesnetzagentur (the federal regulator) required all contracts to be amended according to the rules of the two-contract model or entry-exit system.

During 2006, 2007 and the beginning of 2008, several actions were taken to enhance liquidity on German hubs. E.ON, for example, created the so called "Choice Market" which means that each morning E.ON publishes a price on their website for which they are willing to buy and sell gas, up to a daily maximum. In addition, a joint capacity booking system for Oude Statenzijl (the connection point between BEB and Gasunie) was introduced which facilitates arbitrage opportunities between the two hubs. However, it is important to stipulate there is no (firm or non-interruptible) capacity actually available on the German side, hence, the influence of this measure on liquidity is doubtful in the short-term. Expectations are that the take-over of the transportation division of BEB by the owner of the Dutch transportation grid (Gasunie) mid-2008 will boost liquidity on both BEB and TTF, although it will take some years to implement the changes. Proposals from Bundesnetzagentur will also help boost liquidity in 2008. These changes are designed to implement a daily balancing regime in time for the new gas year in October 2008.

France

France currently has five market hubs, four operated by GRTgaz (a subsidiary of Gaz de France) and one belonging to TIGF (a subsidiary of Total). The most liquid of these is PEG Nord, where approximately 60% of all trade occurs. Traded volumes on all five hubs combined increased to almost 10 bcm in 2007. GRTgaz has plans to merge the three northern PEGs (Point d'Echange de Gaz), named North H, West and East, into one hub by 2009. To boost hub activity, GRTgaz started in February 2008 an experiment in which they give end users direct access to the hubs, through a simplified shipper contract.

Italy

Traded volumes on the Italian PSV (Punto di Scambio Virtuale) also increased in 2007 to 10.6 bcm, or by 63%, and physical volumes by 41% (to 6.3 bcm). Despite this, bringing gas onto the PSV is a major problem for new entrants, as most of the pipeline capacity is booked on existing contracts with Italian incumbents, who have shown a marked lack of enthusiasm to either expand capacity, or offer unused capacity to new entrants. In order to boost liquidity, Eni engaged in a second gas release programme with delivery on PSV. In addition, the Ministry of Economic Development (MSE) ordered producers with large concession licences to auction the equivalent volume of gas they previously would have paid as state royalties on the PSV. In addition, MSE has approved a decree to force holders of new import contracts to offer a certain percentage of their gas volumes to PSV. The decree will come into force on 1 October 2008. However, the decree may have a limited impact on the market as most import contracts are not due for renewal for some time. For new import contracts, it is uncertain whether the additional volume will be marketable: if only the delivery point changes, liquidity will not rise.

Austria

CEGH (Central European Gas Hub) is located in Baumgarten, Austria, at the confluence of the Brotherhood and Transgas pipeline systems that flow Russian gas to Europe. The physical origin of all gas flowing into Baumgarten is Russia. In 2007 the Austrian hub saw traded volumes double to 17.7 bcm and physical volumes increase by 46% to 6.9 bcm. In January 2008, the owner of the hub, OMV Gas International GmbH, and Gazprom signed a deal giving the Russian company a 50% stake in the Austrian hub. Both shareholders stated that they aimed to make the CEGH one of continental Europe's most liquid hubs. However, while Baumgarten holds great importance as a transit point for large volumes of Russian gas, it is not at all clear if the ambitions of the CEGH can be fulfilled in the absence of significant suppliers to the market, other than Gazprom.

REGIONAL DEMAND AND SUPPLY BALANCE TO 2015

This section highlights regional supply and demand balances for the years to 2015, based on data and analysis published in November 2007 in the IEA's *World Energy Outlook 2007*. Price assumptions in that analysis were centred on oil prices at USD 60, with gas priced at around USD 7-8 per MBtu and coal at USD 60 per tonne, reflecting the market outlook at the time the analysis commenced. Analysis for this year's *World Energy Outlook* will be conducted with significantly higher price assumptions, more reflective of current energy prices as of May 2008, of USD 130 oil, gas at USD 10-12 per MBtu, and coal over USD 150 per tonne in some markets. This is likely to lead to differing projections, both in overall energy use and gas. The 2008 *World Energy Outlook* will be available in early November 2008.

World primary energy demand in the *WEO 2007* Reference Scenario is projected to grow by 55% between 2005 and 2030, an average annual rate of 1.8%. Demand reaches 17.7 billion tonnes of oil equivalent, compared with 11.4 billion toe in 2005. The pace of demand growth slows progressively over the projection period, from 2.3% per year in 2005-2015 to 1.4% per year in 2015-2030. Demand grew by 1.8% per year over 1980-2005.

Global demand for natural gas grows by 2.6% per year from 2 854 bcm in 2005 to 3 689 bcm in 2015. As with oil, gas demand increases quickest in developing countries. The biggest regional increase in absolute terms occurs in the Middle East, where gas resources are extensive and prices low. North America and Europe nonetheless remain the leading gas consumers in

Table 6 **World primary natural gas demand (bcm)**

	2000	2005	2015	2005-2015*
OECD	1 409	1 465	1 726	1.70%
North America	799	765	887	1.50%
Europe	477	550	639	1.50%
Pacific	133	149	201	3.00%
Transition economies	601	663	789	1.80%
Russia	395	431	516	1.80%
Developing countries	528	727	1 174	4.90%
China	28	51	131	9.90%
India	25	35	58	5.20%
Other Asia	131	177	262	4.00%
Middle East	182	261	394	4.20%
Africa	62	85	136	4.80%
Latin America	100	118	193	5.00%
World	**2 539**	**2 854**	**3 689**	**2.60%**
European Union	482	541	621	1.40%

*Average annual rate of growth.

Source: IEA WEO 2007, Reference Scenario.

2015, accounting for around 40% of world consumption, compared with just under half today.

New power stations, mostly using combined-cycle gas turbine technology, are projected to absorb over half of the increase in gas demand over the projection period. In many parts of the world, gas remains the preferred generating fuel for economic and environmental reasons. Gas-fired generating plants are very efficient at converting primary energy into electricity and are cheap to build, compared with coal-based and nuclear power technologies. Gas is also favoured over coal and oil for its lower emissions, especially of carbon dioxide. However, the choice of fuel and technology for new power plants will hinge on the price of gas relative to other generating options.

Worldwide gas resources are more than sufficient to meet projected demand to 2015 and beyond subject of course to adequate and timely investment. Gas production is projected to increase in all major regions except OECD Europe, where output from the North Sea is expected to decline. North American growth is expected to slow after 2015. As with demand, the Middle East sees the biggest increase in production in the period to 2015. Output also increases markedly in Africa and Latin America. Natural gas supplies will continue to come mainly from conventional sources, though coalbed methane and other non-conventional supplies are expected to play a growing role in some regions, notably North America. As with oil, projected gas-production trends generally reflect the relative size of reserves. However, unlike oil, transporting gas over long distances is

Table 7 World primary natural gas production (bcm)

	2000	2005	2015	2005-2015*
OECD	1 115	1 106	1 199	0.80%
North America	769	743	820	1.00%
Europe	304	315	292	-0.80%
Pacific	42	48	87	6.10%
Transition economies	732	814	947	1.50%
Russia	576	639	702	0.90%
Developing countries	691	944	1 543	5.00%
China	28	51	103	7.30%
India	25	29	45	4.50%
Other Asia	190	240	310	2.60%
Middle East	212	304	589	6.80%
Africa	131	186	279	4.10%
Latin America	104	134	217	4.90%
World	**2 538**	**2 864**	**3 689**	**2.60%**

*Average annual rate of growth.

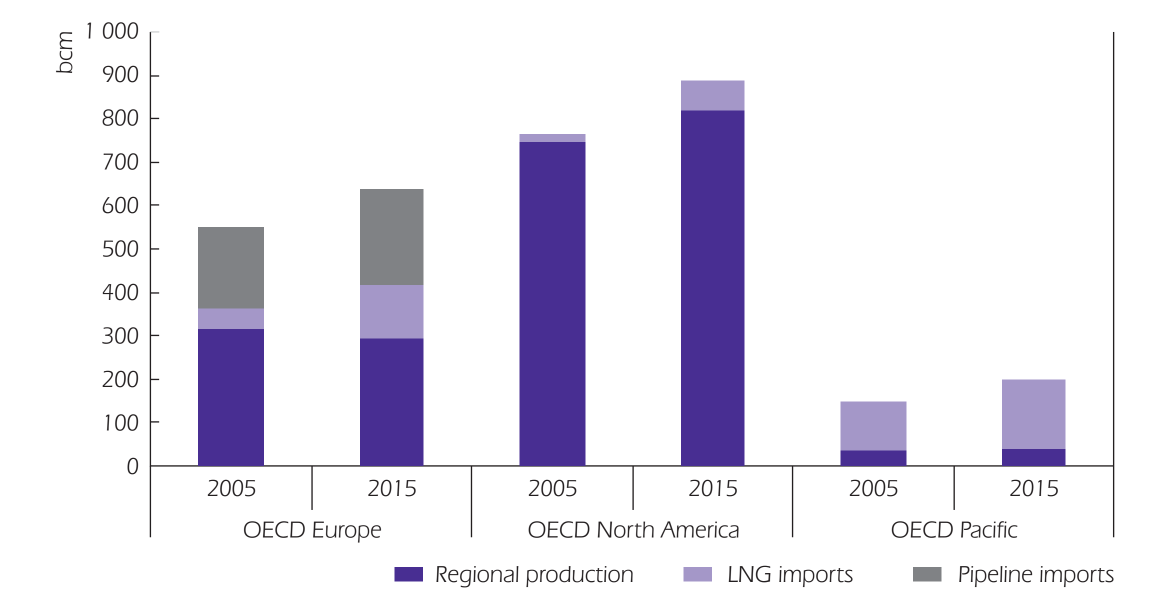
Source: IEA WEO 2007, Reference Scenario.

more costly, and production is also linked to proximity to the main consuming markets. How major resource holders will respond to increasing demand, particularly the rate of investment, rapidly rising costs and development of more remote gas deposits is a matter of considerable uncertainty.

Although most regions continue to be supplied mainly with indigenously produced gas, the share of gas supply that is traded between regions grows from 13% in 2005 to 17% in 2015. All the regions that already import gas (on a net basis) become more import-dependent by 2015, both in terms of volume and, with the exception of OECD Pacific, the share of total consumption. Imports to OECD Europe increase most in absolute terms, from 234 bcm to 350 bcm in 2015. North America, which only recently started importing LNG in significant quantities, becomes a major importer. A significant portion of the increase in global inter-regional exports over the period comes from the Middle East and Africa. Most of these additional exports go to OECD countries.

LNG accounts for about 84% of the increase in total inter-regional trade, with exports growing from 192 bcm in 2005 to approximately 400 bcm in 2015. In OECD North America, inter-regional imports will be expected to come solely as LNG. OECD Europe will be supplied by both pipeline gas and LNG. As domestic production is expected to decrease, the largest growth of LNG imports is expected to be in Europe. In OECD Pacific, Australia is expected to expand its role as intra-regional LNG supplier, as well as an LNG supplier to China.

Figure 11 **Demand and supply outlook for OECD regions to 2015**



Source: IEA WEO 2007, Reference Scenario.

Table 8 **Inter-regional import dependence by major region**

	1980	2000	2005	2015
OECD	8.30%	20.90%	24.50%	31%
North America	1.40%	3.80%	2.90%	8%
Europe	18.10%	36.30%	42.70%	54%
Pacific	65.70%	68.40%	67.80%	57%
China			0.00%	21%
India			17.10%	22%

Source: IEA WEO 2007, Reference Scenario.

INVESTMENT IN NEW SUPPLY PROJECTS

Gas demand in OECD countries is steadily growing, by about 1.8% per year to 2015, while at the same time indigenous production is reaching a plateau. Therefore, new supplies must be brought to markets to meet additional needs and to replace depleted local sources. Infrastructure to deliver new gas supplies – pipelines and LNG facilities – built in a timely manner is essential, as of course is the increasingly remote and costly gas production to fill them.

Transmission pipelines represent costly investment projects, spread over long time-scales and across geographical regions. Such assets tend to be dedicated to a given geographical market and often provide limited flexibility. Pipeline projects can be seriously delayed by geopolitical and market tensions. These specificities need therefore to be taken into account by policy makers when analysing the investment outlook in gas markets.

Pipeline investment in North America

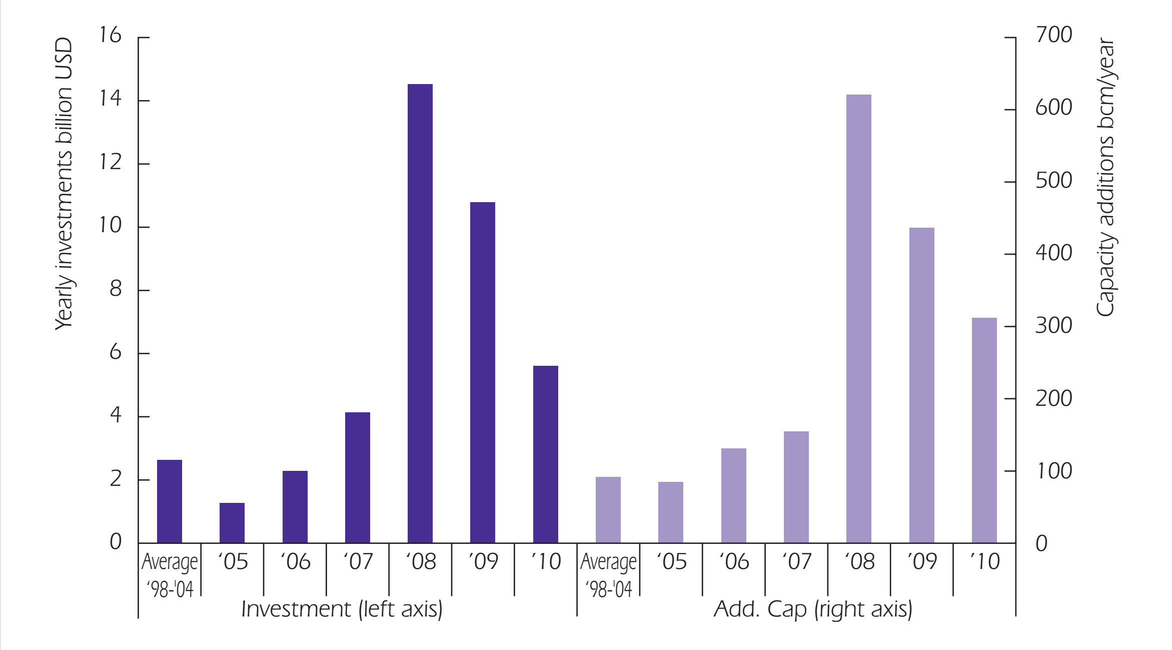
In North America, the investment climate for new pipeline projects has been relatively transparent and investor-friendly, and yielded visible results in terms of realised projects. However, the main challenges for North American pipeline development, as for new LNG terminals, are environmental compliance and social acceptance, and the high capital costs associated with some projects.

A large number of natural gas pipeline projects were completed in North America in 2007, the majority of which were in the United States. Preliminary data provided by the Energy Information Administration (EIA) shows a total of 51 pipeline projects with a value of USD 4.1 billion, completed in 2007, adding 155 bcm per year of pipeline capacity. Capacity additions in 2007 were 18% higher compared to 2006, and almost double those in 2005.

It is expected that pipeline additions and investment will expand further over the coming years. Up to 600 bcm per year of capacity additions will be realised if all proposed projects were implemented. However, more than one-fifth of the proposed projects (130 bcm) are still awaiting regulatory approval from the FERC. As a result, some projects may be postponed until 2009. However, pipelines currently under construction and likely to be completed by the end of 2008 will make the 2008 incremental capacity additions significantly higher than last year.

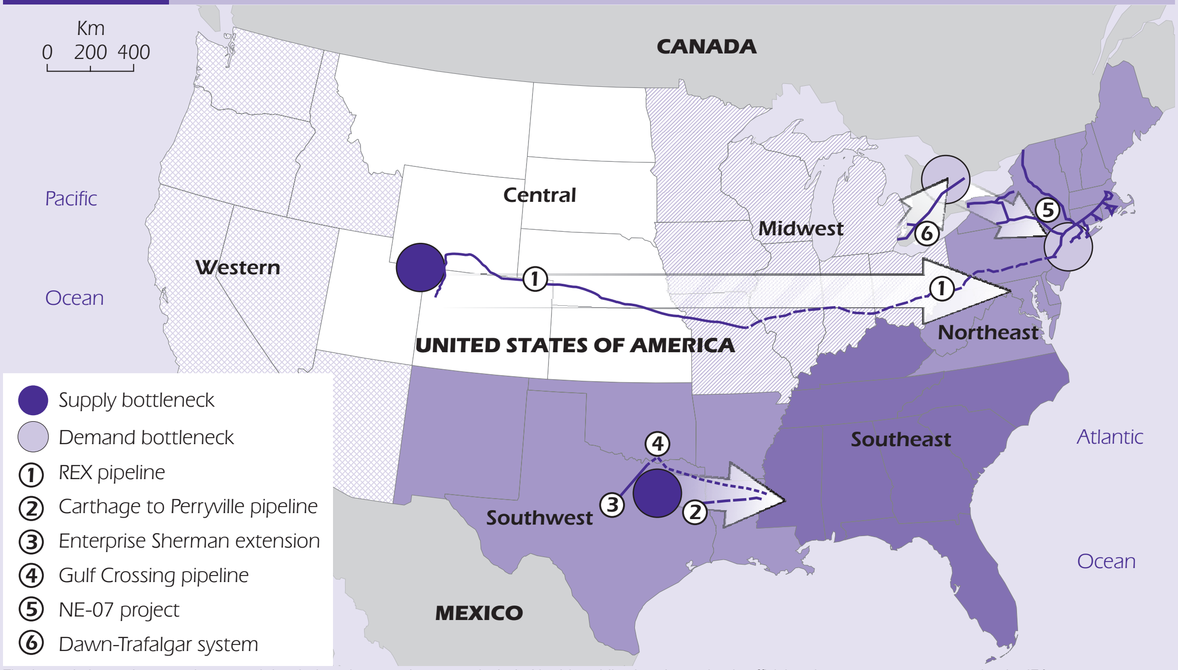
A primary reason for investing in pipeline infrastructure is the (anticipated) regional imbalance in supply and demand and its allied price signals. As noted earlier, natural gas can be traded or priced at almost any location in North America: there are 38 different hubs in the United States and nine in Canada. Normally, if sufficient capacity is available to transport gas between hubs, price differentials between these hubs will represent the transportation costs between the locations. However, if there is a lack of capacity to balance supply and demand, price differentials can rise above these transportation costs. For example, in a producing region supply may exceed

Figure 12 **Actual and expected United States capacity additions and total amount invested**



Source: EIA, United States Department of Energy.

Map 1 **United States: capacity expansion and potential bottlenecks**



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 analysis.

Note: The six United States' regions shown in this figure are based upon the regions used by the Office of Oil and Gas of the EIA.

demand if there is not enough take-away capacity; in a consuming region it is possible for potential demand to exceed supply if there is insufficient delivery capacity. Price differentials between regions will reflect these market circumstances. Systemic price differentials will provide pipeline companies an incentive to build new gas infrastructure.

It is possible to identify several regions in the United States where imbalances between supply and demand exist. Map 1 shows the four main bottleneck regions. Table 9 presents existing and planned investments per region. It is clear the majority of recent and planned investments are near the bottlenecks.

Central Region: increasing supply in the Rocky Mountains area

The Central Region, comprising the states of Montana, North Dakota, South Dakota, Wyoming, Nebraska, Utah, Colorado and Kansas, is a major producing area. The area contains nearly 22% of total natural gas reserves in the United States. Currently, production is much higher than local consumption, allowing gas to be exported to other regions. Gas production within the major natural gas basins of the Rocky Mountains is expected to increase to 136 bcm by 2010. However, in recent years, the interstate pipelines exporting natural gas to other United States regions have been running close to maximum capacity, resulting in low and volatile producer prices in the

Table 9 United States: added capacity and planned investments per region

Region	Added Capacity (bcm per year)						Investment (USD billion)					
	'05	'06	'07	'08	'09	'10	'05	'06	'07	'08	'09	'10
Central	3	40	45	71	15	3	0.1	0.8	1.5	2.2	0.3	0.2
Midwest	5	5	5	12	51	0	0.1	0.1	0.0	0.5	2.3	0.0
Northeast	6	11	18	67	73	85	0.1	0.2	0.8	2.1	1.1	1.5
Southeast	8	4	5	119	89	108	0.2	0.0	0.3	3.8	3.5	1.7
Southwest	57	45	56	335	194	53	0.7	0.7	1.4	4.9	1.4	0.3
Western	5	1	7	8	2	48	0.1	0.0	0.0	0.7	0.0	1.1
Other[6]	0	25	19	9	2	15	0.0	0.4	0.2	0.3	2.1	1.0
Total	**85**	**131**	**155**	**621**	**437**	**312**	**1.3**	**2.3**	**4.1**	**14.5**	**10.8**	**5.6**

Source: EIA.

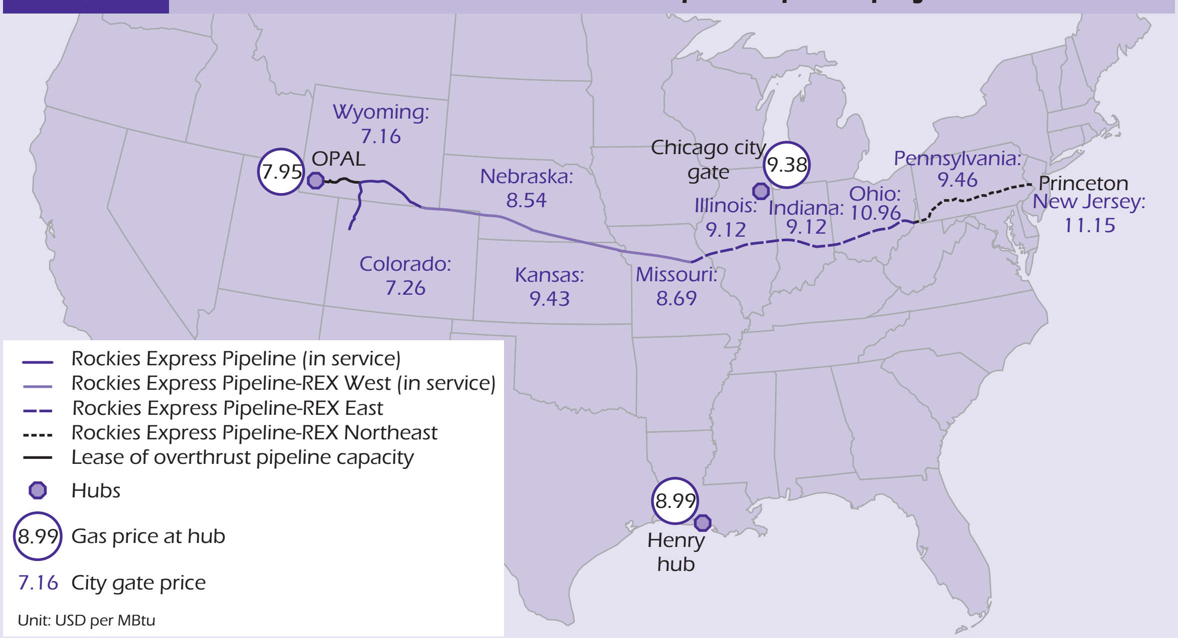
6. Investments in pipelines in Alaska and off-shore areas and in pipelines from the United States to Mexico or Canada.

Rocky Mountains area. In order to market the anticipated new production, extra infrastructure was needed.

The most significant investment in the Rocky Mountains area is the Rocky Express pipeline (REX-pipeline) which commenced in 2005. The first stages of this pipeline are complete (see box 1). The completion of the first phases of this project has reduced the continuing price differences between producers in the Rocky Mountains region and consumers in the Midwest. There are several other new projects planned and expected to be completed in the Rocky Mountains region in 2008. Total added capacity of these projects will be 24.4 bcm per year. As a consequence of projected growth in gas production, additional pipeline capacity will be needed to prevent continuing transportation bottlenecks for deliveries out of the Rockies production region.

In order to meet this requirement, three open seasons for pipelines which will move natural gas supply from the Rockies to markets in the eastern United States started in the spring of 2008. The first phase of the Pathfinder Pipeline project, an 805 km and 12 bcm per year pipeline, is proposed to start operations by late 2010; the Sunstone Pipeline, a 995 km and 12 bcm per year pipeline, is expected to be completed in 2011 and the Rockies Alliance Pipeline, an approximately 1300 km and 12 bcm per year pipeline, is planned to start shipping gas as early as the third quarter 2011.

Map 2 **United States: overview of Rockies Express Pipeline 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: IEA analysis.
Note: Prices as of March 2008.

Box 1 **United States: Rocky Express pipeline (REX-pipeline)**

In 2005, the signing of a Memorandum of Understanding between Kinder Morgan Energy Partners and Sempra Energy marked the start of the construction of the largest pipeline in the last 20 years: the Rocky Express Pipeline (REX-pipeline). The 2 700 km pipeline crosses eight different States, at a total cost of USD 4.4 billion. It will open up producing areas in the Rocky Mountains to consumers in the east.

The pipeline is composed of four parts (see map 2). The first part, REX-Entrega, is 528 km long and was finished in February 2007. The second part, connecting Colorado to Missouri, REX-West, is 1147 km long and was completed in January 2008. Together the REX-Entrega and the REX-West pipeline have 15.5 bcm per year capacity. The final part, REX-East, a 1027 km extension, will connect the REX-West pipeline to Ohio. FERC gave approval to begin construction of this section in May 2008. Construction will start in mid-2008 and the pipeline will be partially in service in December 2008. Expectations are the pipeline will be fully operational in June 2009. Capacity of this part of the pipeline is 18.5 bcm per year. In 2007 an open season was held to extend the pipeline further northeast to New Jersey.

The business case for the REX pipeline was based on expectations of potential price differentials at either end once construction was complete. These expectations were appropriate, as evidenced by the price differentials that can be seen in 2006, 2007 and the beginning of 2008. The capacity of the pipeline was sold before the pipeline itself was built, using an open season process. In this process, expressions of interest were sought by the pipeline company from any shipper. The pipeline open season attracted interest from several gas traders and producers.

Following the open season, Rocky Express executed binding agreements for the long-term lease of capacity. Total upfront commitments from all shippers to the project amounted to over USD 4 billion – enough to allow the pipeline to be constructed.

As an inter-state pipeline, the REX Pipeline is under the jurisdiction of FERC, who also coordinated the participation of other state and federal agencies such as Environmental Protection Agency and the Department of Transportation's Office of Pipeline Safety. In order to secure the project's regulatory approval, dialogue was initiated with FERC as soon as the start of the project, which enabled tight cooperation. The regulatory process was run in parallel to the project development, saving much time for the sponsors who would normally have run the regulatory process in series (one regulatory stage following a project stage, etc.). The rapid, transparent, expeditious regulatory processes for a pipeline crossing several state boundaries and the close cooperation with FERC were not the only reasons the

Box 1 **United States: Rocky Express pipeline (REX-pipeline) - continued**

project proceeded from concept to operation in 3 years. Other key factors in this relatively rapid process were:

- Transparent market signals that gave investors confidence in project fundamentals.
- Open season processes allowed the identification of potential markets for pipeline services in advance of construction, which enables "right-sizing", timing of the pipeline and attracting project finance.
- Efficient communication between producers/traders and the pipeline owner-operator.
- Close ties between the community and the pipeline owner-operator. In November 2005, FERC granted the REX proposal to commence the FERC pre-filing process, a process which helped identify landowners, state and local officials and others with an interest and gave insight into the scope of public interests and issues. After this identification, the operators kept stakeholders informed and involved in the project.
- A pipeline route along existing pipeline corridors and easements.

Southwest Region: increasing supply in the Texas area

The Barnett Shale region in northeast Texas is one of the most promising natural gas production development areas in the United States. Production is expected to nearly double over the coming years from 15 bcm per year to 30-40 bcm per year. Current pipeline capacity is not sufficient to accommodate forecast production growth. Several projects are newly designed to mitigate this projected capacity constraint.

A typical example of a newly built pipeline connecting east Texas with higher value markets is the Carthage to Perryville pipeline. This 277 km pipeline was constructed in two phases, both finished in 2007. It created the opportunity to move volumes from east Texas and northern Louisiana supply points to the Perryville Hub and eliminated the price differences between east Texas and Louisiana. A third phase is anticipated in 2008 expanding the pipeline with a further 3 bcm per year, to 15.5 bcm per year.

There are a number of additional projects being planned and constructed for completion in 2008. One is the Enterprise Sherman Extension, which will extend the current Texas intrastate pipeline system by 286 km and and will carry 11.4 bcm per year. The pipeline will pass through the centre of the Barnett Shale area and will make deliveries into the Gulf Crossing Pipeline, which will also be completed by the end of 2008. From the interconnection with the Enterprise Sherman Extension, the Gulf Crossing pipeline will take gas supplies to the Perryville hub. Total capacity of this pipeline will be 17.6 bcm per year.

Northeast Region and Canada: increasing demand in New York, New Jersey and east Canada

There are several infrastructure projects scheduled to commence in 2008 to accommodate growing demand in eastern Canadian markets (Ontario, Quebec) and the United States' Northeast region (New York, New Jersey and New England). Construction of the 292 km, 5 bcm per year Millennium pipeline from Corning to Ramapo started in the summer of 2007. The Millennium pipeline is an upgrade of the existing Columbia Gas Transmission pipeline and will be a vital link in the larger NE 07 Project. This project will connect the liquid Canadian Dawn supply hub to eastern markets in the United States and is planned to be finished in the fourth quarter of 2008. Another project that is expected to be completed in 2008 is the third expansion of the Dawn-Trafalgar system in Ontario.[7]

Alaska: huge supply potential[8]

The Alaska North Slope has considerable proven gas reserves of about 1 000 bcm and estimated resources of another 5 700 bcm. The Alaskan Pipeline is designed to bring North Slope natural gas to markets in the lower 48 States.

There have been many developments over the last year in regard to the Alaskan pipeline, a much debated project since the 1970s. In 2004, the Alaskan pipeline almost seemed about to become reality when Congress passed the Alaskan Natural Gas Pipeline Act and the producers negotiated an agreement with the governor of Alaska on fiscal terms. Due to a change in the Alaskan government the agreement has never been approved and the pipeline development became dependent on the State of Alaska selecting a viable commercial proposal under the Alaska Gasline Inducement Act (AGIA). This act was signed in June 2007 and provides up to USD 500 million in matching funds to help the project complete an Environmental Impact Statement, conduct an open season, and complete the required regulatory application.

In November 2007 a total of six companies submitted proposals to build the Alaskan pipeline, of which five applied under the AGIA. In January 2008 the Alaska government selected only the TransCanada application for further evaluation – it was the only one deemed compliant with AGIA. This USD 26 billon investment offer contained a 2 760 km pipeline together with a gas treatment plant at Prudhoe Bay (if no other party is willing to own and operate it). The offer also included a mechanism where the United States government acts as a bridge shipper – which means agreeing to cover some of the transportation fees if producers fail to commit enough gas to operate the pipeline at full capacity. In May 2008 the Alaskan governor announced that TransCanada's offer was accepted. In April 2008, Conoco

7. Investments (USD) related to this Canadian project are not included in table 9.
8. Alaska is not presented in map 1.

and BP agreed to build a rival project. FERC have allowed Conoco and BP to initiate a "pre-filing" proposal before the initial application is made. This process will allow FERC staff an opportunity to review and consider the new proposal before a formal application is made. However, many issues remain unresolved, and even the most optimistic timeline does not anticipate gas delivery from Alaska to the markets before 2018.

New transmission pipeline projects in Europe and Central Asia

Gas pipeline investment is crucial in Europe, if gas is to be brought to markets from increasingly remote producing regions. Intra-regional connections need to be strengthened to provide greater resilience, security and competition in gas supply. When compared to North America, European investment remains relatively weaker, and long-haul pipelines are subject to delay and cost escalation. Many proposals remain at the planning stage.

Supplies from Norway

Norway-United Kingdom: Langeled and Tampen link – newly completed

The Langeled pipeline, connecting the Ormen Lange field (proven reserves: 375 to 397 bcm) in the Norwegian North Sea to Easington in the United Kingdom, was inaugurated in October 2007. Langeled is the world's longest sub-sea pipeline (1 200 km from western Norway at Nyhamna to Easington in the United Kingdom). Added to the BBL pipeline commissioned in December 2006[9] (16 bcm per year) and to new LNG import capacity available, the present import capacity of the United Kingdom should be sufficient to ease supply tensions that characterised recent winters. Langeled, the sole transport route for gas from Ormen Lange and dedicated to the United Kingdom, should provide up to 25.5 bcm per year. Including Langeled, the total pipeline import capacity of the United Kingdom market will meet more than half of total gas demand, as the Interconnector's capacity extension was completed in October 2007 raising technical capacity to 25.5 bcm per year. The United Kingdom's supply has also been enhanced by the addition of the Tampen link, a 23 km connection from the Statfjord Field in the Norwegian North Sea to the Flaggs pipeline reaching land at St Fergus in Scotland.

Norway-Sweden-Denmark-Poland: Scanled and Baltic Pipe – proposed

The Scanled pipeline is a proposed project to transport gas from Norway to Sweden and Denmark. Scanled is a joint venture of local companies led by the Norwegian TSO Gassco, with an estimated cost of EUR 900 million for a pipeline to be commissioned in 2012; a final investment decision is expected in 2009. Scanled will have the potential to transport 7 bcm per year from Karsto, north of Stavanger, to southern Norway (notably Oslo), Sweden and northern Denmark.

9. See Natural Gas Market Review 2007.

A continuation of this project is the 3 bcm per year Baltic Pipe, which is a two-way interconnection project between Poland and Denmark. Poland has long sought Norwegian gas supplies to mitigate its dependence on Russian gas. However, such plans have not come to fruition, mainly because of the relatively small size of the Polish market and the substantial investment needed to build a sub-sea pipeline from Poland to Norway. The Scanled venture presents a new opportunity for Poland to build a westward connection. The Polish oil and gas incumbent, Polskie Górnictwo Naftowe i Gazownictwo (PGNiG) has a 15% interest in Scanled, and is promoting the Baltic pipeline together with the Danish TSO, Energinet, and the Polish TSO, Gaz System.

The cancelled Gas Network Expansion (GNE) project

Late in 2007 the Norwegian government halted the planned expansion of the Troll gas field. The Gas Network Expansion (GNE) project associated with this field development had been the subject of discussions between Statoil and several western European companies, and had the potential to bring additional Norwegian pipeline supplies to the region. If realised, the GNE pipeline could have added 20 bcm per year of supply capacity to Europe. However, the Troll expansion plan has been stopped and therefore the GNE project has been cancelled.

Supplies from Russia

Russia-Germany: Nord Stream, Opal and Nel

Nord Stream is a proposed gas pipeline to link Russia with Germany via the Baltic Sea. The aim of the pipeline is to transport Russian gas into Western Europe while bypassing transit countries such as Ukraine, Belarus and Poland. In addition to 51%-shareholder Gazprom, Nord Stream comprises Germany's E.ON and BASF-Wintershall, each with 20%, and Gasunie of the Netherlands holding the remaining 9%. Gasunie entered the Nord Stream project in 2007. In exchange for its participation, Gazprom received a 9% stake in the BBL pipeline that links the Netherlands with the United Kingdom, providing a potential outlet for Russian gas in the United Kingdom.

Nord Stream, initially planned to cost EUR 5 billion (offshore section only), and to come on stream in 2010, has recently experienced difficulties, as cost estimates have increased significantly (to almost EUR 8 billion), and Baltic and Scandinavian states have expressed concerns about the environmental and geopolitical impact of the offshore pipeline. The choice of maritime route for the 1 200 km pipeline across the Baltic Sea remains to be finalised. The European Commission has expressed its support for this project as it will bring an additional 55 bcm per year of supply capacity (two parallel pipelines of 27.5 bcm) to the European market. However, a land route of a similar size may better reach the objectives of regional market integration and cost optimisation of energy investments.

As an extension of the Nord Stream project, the German gas operator Wingas, partly owned by Gazprom (50% less 1 share), intends to build two pipelines transporting Russian gas – Nel, reaching North-West Germany, and Opal, parallel to the Polish border. Opal, a 480 km pipeline project, 37 bcm per year, would reach the Transgas line (end of Brotherhood line) on the Czech-German border.

If Nord Stream and its European branches, Opal and Nel, are built and fully utilised, it is possible that historical transit routes (Brotherhood-Transgas and Yamal), will have lower capacity utilisation rates.

The branch of Brotherhood flowing into the Czech Republic, Transgas, fully owned by RWE, might for example be affected: it was designed in the past to bring gas to southern Germany from Russia. The new Opal project intends to reach the same customers but from the northern route, reaching the north-western exit point of Transgas on the Czech-German border (Olbernau/Hora Svate Kateriny). In the future it might even be possible that gas flows from Nord Stream could reverse the traditional East-West transit through the area. This new supply may be more expensive when compared with the mature link of Brotherhood-Transgas as the Nord Stream route is longer, partly offshore and newly built. It will have the advantage, for the Russian supplier, of not crossing any of the traditional transit countries – Ukraine, Slovak and Czech Republics.

In anticipation of the shift in gas flows in Central Europe as a consequence of the Nord Stream project, another pipeline is proposed by RWE Transgas Net. This new project, called Gazelle, will run from Olbernhau/Hora Svate Kateriny, in the north of the Czech Republic, to Rozvadov/Waidhaus in the west at the German border, allowing gas from Nord Stream to join the historical gas flow from Ukraine through the Megal pipeline to Germany and France. The overall construction costs of the new pipeline will amount to EUR 400 million, and it is expected to become operational in 2011.

Russia-Bulgaria-Central Europe and Italy: South Stream

In 2007, the proposed South Stream project became the centrepiece of Gazprom's export strategy across southeast Europe, superseding or incorporating various other gas transportation initiatives that had been under discussion (*e.g.* Blue Stream II). The project was launched in June 2007 with the signature of a Memorandum of Understanding (MoU) between Gazprom and the Italian gas incumbent Eni. Italy is the second-largest European market for Russian gas with annual imports from Russia amounting to about 22.5 bcm (of a total market size of 85 bcm per year in 2007). The Eni-Gazprom MoU is considered part of a broader partnership agreement signed in November 2006.

South Stream is a challenging project, both because of its offshore length of 900 km, and depth (2 200m compared to an average of 200m in the Baltic Sea for Nord Stream). It will also be a costly venture, with estimates reaching USD 20 billion. The sub-sea pipeline will run from Beregovoye on Russia's Black Sea coast to Bourgas in Bulgaria. From Bourgas the project could branch northwest to Serbia and Hungary and south to Greece and under the Adriatic Sea to Italy.

Early in 2008, Eni and Gazprom created a jointly owned (50/50) project company, South Stream AG, tasked with conducting a feasibility study to be completed by the end of 2008. The marine section of the pipeline would be owned and operated exclusively by Gazprom and Eni on a 50/50 basis. Agreements on the onshore branches were also concluded with Bulgaria, Serbia and Hungary. The rapid announcement of these agreements demonstrates Russia's ability to reach bilateral agreements with selected consumer and transit countries, both inside and outside of the European Union.

Supplies from the Caspian

Gas exported from this region is mainly transited through Russia, as four of the producing states in the region (Uzbekistan, Turkmenistan, Azerbaijan, and Kazakhstan) were part of the former Soviet Union for much of the latter half of the 20th century, resulting in the central management of their reserves and exports from Moscow. After the break-up of the Soviet Union, several attempts to build direct pipelines from the Caspian region were made by European and United States companies. Currently, a number of ventures to source gas from this region for European consumption are under development, and considered priority projects under the TEN-E program.

The Trans-Balkan route: Nabucco

The Nabucco pipeline project was granted special status in 2007 when the European Commission appointed a coordinator (Jozias Van Aartsen) for the Caspian/Middle East to European Union natural gas route ("fourth corridor"). Nabucco is driven by midstream and downstream players: two gas transport operators and three integrated gas incumbents from Central and Eastern Europe and Turkey. In early 2008, RWE joined the project as a sixth partner. Not having an upstream player involved directly, nor a clearly identified supply source, explains partly the delays in Nabucco's advancement. The difficulties in achieving strategic alignment between the five initial shareholders (OMV, MOL, Transgaz, Bulgargaz and BOTAS) also contributed to the slowing of the venture.

Without the direct involvement or influence of an upstream player, project development is complicated by the necessity of an iterative process of capacity allocation that allows prospective shippers to secure upstream supplies once they have secured a tranche of the shipping capacity.

Recent progress in moving into the design stage of the project, and the addition of a sixth shareholder which will give the pipeline direct access to the large German gas market, have increased the prospects of its successful development. More recent analysis of future EU gas demand also indicates that there should be sufficient demand within Europe for a number of projects bringing additional gas into Europe; to replace declining EU production and to meet increasing demand. The sequencing of projects to bring Caspian and Middle East gas to Europe, including Nabucco, and their ultimate success, will depend also on political and gas supply developments in the regions that are expected to provide the gas to feed into the pipelines.

An outlet for Caspian gas: SCP

Azeri gas from the promising field of Shah Deniz first reached Turkey in summer 2007, following the 690 km South-Caucasus pipeline (SCP, also known as Baku-Tbilisi-Erzurum pipeline or BTE), crossing Azerbaijan, Georgia and ending at Erzurum in eastern Turkey. Shah Deniz and the south Caucasus pipeline are privately driven investments – shareholders include BP, Statoil, and other oil and gas companies, including the Azerbaijan State Oil Company (SOCAR). Reserves of Shah Deniz are estimated at around 640 bcm (further details may be found in the Caspian section).

Production under Phase 1 of Shah Deniz should reach 8.6 bcm, and this will be split between Azerbijan (1.5 bcm), Georgia (0.8 bcm) and Turkey (6.6 bcm), according to a contract signed in 2003. Initial volumes delivered in 2007 were low (1.2 bcm to Turkey), as were prices (USD 120 per mcm for sales to Turkey), but both volumes and prices are set to rise significantly in 2008.

The Southern Balkan route: ITGI and TAP

Interconnector Turkey-Greece-Italy

The Turkey – Greece – Italy Interconnector (ITGI) consists of three portions, one linking Turkey with Greece, which was commissioned in 2007, a second pipeline in Greece and a third offshore pipeline from Greece to Italy crossing the Adriatic Sea (Poseidon Project). It is planned that each country will manage the portion of the pipeline running through its territory ensuring the transit of gas to its neighbour.

In July 2007, a trilateral agreement between Italy, Greece and Turkey was signed, setting out a commercial framework for gas trade and transit.

The Turkey-Greece Interconnector is a 295 km link between Karacabey in north-western Turkey and Komotini in the eastern part of Greece. This pipeline was successfully inaugurated in November 2007 and Azeri gas reached the EU market for the first time. The pipeline's maximum capacity is designed to reach 11.5 bcm per year. Early deliveries from Turkey to Greece are relatively small (0.25 bcm), however, they mark a symbolic step towards the completion of the fourth corridor in southeast Europe.

The next phase of the project is the Greece-Italy interconnector, with 600 km on Greek territory and 215 km offshore. The 600 km onshore pipeline will run from Komotini to Igoumenitsa on the Ionian Sea and will be included in the Greek transportation system (operated by National Natural Gas System Administrator or DESFA). The offshore portion, the Poseidon pipeline, will be developed as a joint venture between Edison and the Public Gas Supply Corporation of Greece (DEPA), and is expected to be completed in 2011. Its capacity will be 8 bcm per year, with 80% of the capacity reserved by Edison, and 20% by DEPA for 25 years.

The completion of these pipelines may turn Greece into a transit hub for gas to Western Europe. Initially, gas will come from Azerbaijan via Turkey. Eventually, gas from Iran and Turkmenistan, and from Siberia, via Russia and Turkey, could also run through the pipeline.

Trans-Adriatic pipeline – TAP

The Trans-Adriatic pipeline project was proposed in 2003 by the Swiss company EGL. With a length of 520 km, of which 90 km is offshore, and an initial capacity of 10 bcm per year, TAP is similar to ITGI as it intends to bring Caspian gas through Turkey and Greece to Italy, but with a shorter route through another transit country, Albania. From the perspective of integrating Albania in a new transit route, TAP also serves the purpose of regional integration and gasification of the Western Balkans region, still under-developed in the context of natural gas use. Crossing Albania also allows a reduction of the offshore route when compared to ITGI.

The pipeline project contains additional options such as building an LNG terminal on the Albanian coast, as well as an underground storage site, partly as a response to difficulties in obtaining permits to build new infrastructure in Italy. Thus, not only would the project bring Caspian gas to Italy by pipeline, but also LNG supplies from the Albanian coast, with additional flexibility provided by storage. If the terminal and storage facilities are built, the offshore section may be expanded to 20 bcm per year.

The TAP project underwent long stages of preliminary studies and received pre-feasibility funding from the European Union. In late 2006 (announced June 2007) EGL signed an agreement with Iran for up to 5.5 bcm of gas for a 25-year period delivered through the existing Iran-Turkey pipeline to commence when TAP is completed. In 2008 StatoilHydro took a 50% stake in the EUR 1.5 billion project, opening a potential supply input for TAP (Statoil having a 25.5% stake in the Shah Deniz field). A final investment decision is expected in 2009 once the feasibility and environmental impact studies are finalised, with completion forecast by 2011.

Other Caspian pipeline projects

Caspian Coastal Pipeline/CAC upgrade

The main current pipeline infrastructure for transportation of east Caspian gas originates in central and eastern Turkmenistan and leads north through Uzbekistan and Kazakhstan, with the main export lines joining the Russian system at Alexandrov-Gay, located near the Russo-Kazakh border. Russia has a longstanding desire to see this infrastructure modernised and upgraded in order to reinforce its position as the main corridor for east Caspian access to international markets. This was reflected once again in a Declaration on the Development of Gas Transportation Capacity in Central Asia, signed by the Heads of State of the four concerned countries in May 2007. The modernisation and expansion of the Central-Asia Centre Pipeline aims to increase capacity from the current 54.8 bcm per year up to 80 bcm per year in 2012 (actual transit volumes along CAC in 2000 were 32.1 bcm, in 2005, 46.4 bcm).

In addition, there was a widely reported Declaration on the Construction of the Caspian Coastal Pipeline, also signed in May 2007 by the Presidents of Russia, Kazakhstan and Turkmenistan, and supplemented in December 2007 by a Trilateral Agreement on Cooperation in the Construction of the

Caspian Coastal Pipeline. The aim of the pipeline is to bring gas from onshore and offshore fields in western Turkmenistan northwards to join the Central-Asia-Centre lines in Kazakhstan. At present, gas production in these areas is associated gas from oil production. Such a pipeline already exists, with small reported flows of 400 mcm in 2006. It is not yet determined whether the existing line would be upgraded or whether a new line will be laid in the same corridor, but the announced intention is to have an initial pipeline capacity of 10 bcm per year in 2010, potentially rising to 20 bcm per year. The overall objective of these pipeline plans is to accommodate increased volumes of Turkmen gas export, new Uzbek exports (on the basis of Russian investment in Uzbekistan) and increased production of associated gas in western Kazakhstan.

Turkmenistan-Kazakhstan-Uzbekistan-China Pipeline

In 2007, the plan to build an eastern route for Caspian gas was advanced with the project for a new 30 bcm per year capacity gas line from Turkmenistan to China, where it would link up with the West-East pipeline across China. In April 2007, a China-Uzbek agreement on pipeline construction and operation was signed. In July 2007 a China-Turkmenistan gas supply contract was concluded for 30 bcm per year over 30 years and a production sharing agreement (PSA) with the China National Petroleum Corporation (CNPC) for reserves on the right bank of the Amy Darya river in eastern Turkmenistan. In November 2007, an agreement was reached between CNPC and KazMunaiGaz of Kazakhstan on pipeline construction and operation.

In December 2007, CNPC announced that it will invest USD 2.16 billion in the pipeline project, out of a total cost that is estimated at USD 7.31 billion. There were reports in January 2008 that agreement had been reached on a price of USD 195 per mcm at the western Chinese border, which would equate to a price of around USD 145 per mcm at the Turkmen border. Deliveries are scheduled to begin at the end of 2009, which appears very ambitious given that this is contingent upon the completion of a pipeline running for around 2 500 km before reaching the Chinese border. Nonetheless, as and when this pipeline is completed, the opening of a large-capacity alternative to the Russian export route will be a significant shift in the politics and economics of east Caspian gas.

Turkmenistan-Afghanistan-Pakistan-India Pipeline

This longstanding pipeline plan also gained momentum in 2007, although it remains very much at the planning stage. The drivers for this project are strong projections for natural gas demand in Pakistan and India, Turkmenistan's desire for diversified export markets, and support from the Asian Development Bank. The pipeline route is around 1680 km, originating from the Dauletabad field in south-eastern Turkmenistan, with a capacity of around 30 bcm per year. Political support for the project is in place, but progress will in practice depend upon three factors: confirmation of the resource base in Turkmenistan, stabilisation of the security situation in Afghanistan, and negotiations on pricing.

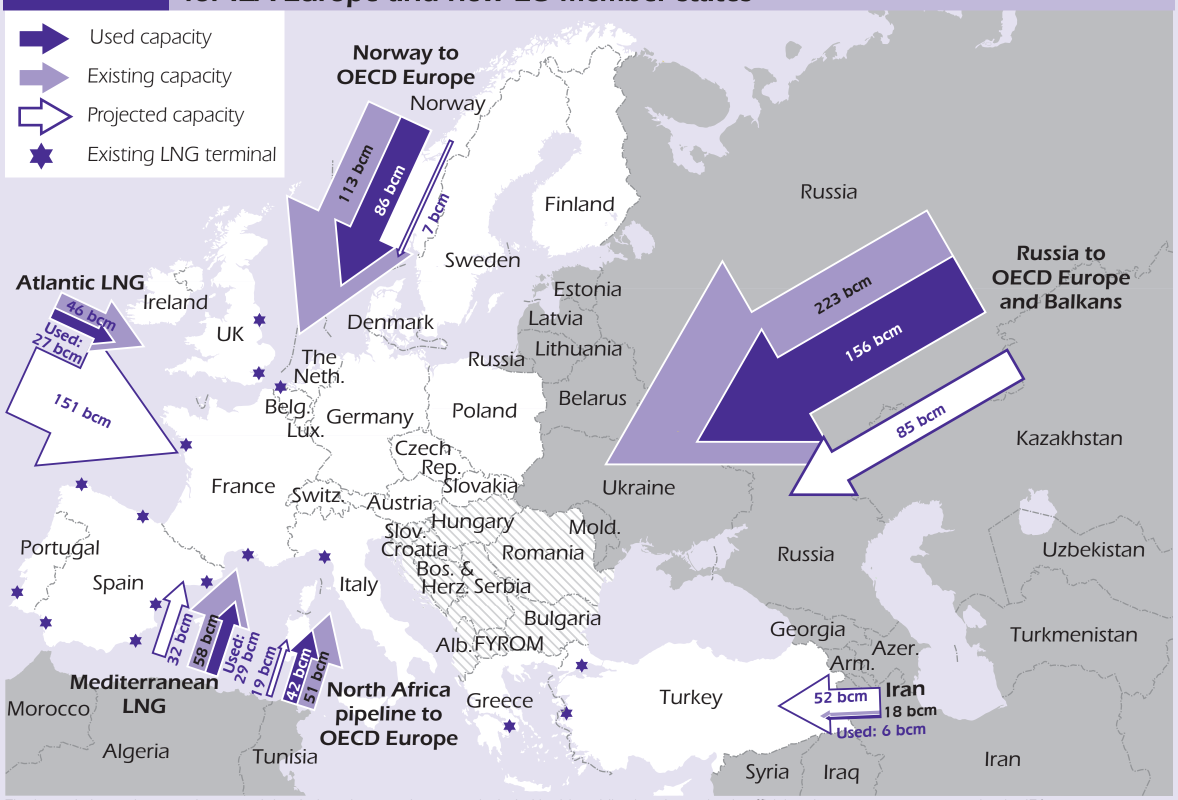
Trans-Caspian issues

A summit meeting of Caspian leaders in Tehran in October 2007 showed little sign of consensus on issues of oil and gas transportation or on the legal status of the Caspian Sea. Instead, the development with most potential implications for trans-Caspian energy trade was the improvement in relations between Turkmenistan and Azerbaijan.

After President Berdymukhammedov came to power in Turkmenistan in February 2007, formal inter-governmental contacts were resumed in the autumn of 2007 after a break of seven years, and Turkmenistan announced in spring 2008 a decision to re-open an Embassy in Azerbaijan. The most visible sign of the warming of relations was the visit of President Berdymukhammedov to Baku in May 2008.

The relationship between Turkmenistan and Azerbaijan is a pivotal one for the prospects of trans-Caspian gas trade, whether this is in the form of Turkmen offshore gas being landed in Azerbaijan, trans-Caspian gas shipments (possibly as CNG) or, in the medium-term, a fully fledged trans-Caspian pipeline feeding into the Azerbaijan gas pipeline

Map 3 **Comparison between supply capacities in 2006 and 2015 for IEA Europe and new EU member states**



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, GIE, company information.
Note: Norway is considered here as a supplier to Europe.

infrastructure. Despite the uncertainty over pipeline routes and over the availability of additional Turkmen gas for export, the European Commission announced, following talks in Ashgabat in April 2008, that Turkmenistan was ready to commit 10 bcm per year to trade with Europe.

Supplies from North Africa

Algeria-Spain: Medgaz

The Medgaz pipeline linking Algeria (Beni Saf) directly with Spain (Almeria), thus bypassing the historical transit through Morocco, is already under construction and will have an initial capacity of 8 bcm per year, for a length of 210 km and an investment of EUR 900 million. Started in 2001, it is expected to be commissioned in 2009. It is important to note that part of the gas entering Spain could continue north through Spain-France interconnectors (see project MidCat), thus contributing to the reinforcement of gas flows within the European market.

Algeria-Italy: Galsi

The proposed Galsi project was initiated in 2003 and has the following shareholders; Sonatrach 36%, Edison 18%, Enel 13.5%, Wintershall 13.5%, Sardinia region 10% and Hera 9%. It is designed to link Algeria directly with Italy through the island of Sardinia, crossing 530 km in water depths of up to 2 000 metres. An intergovernmental agreement between the two countries marked the advancement of Galsi in 2007. The pipeline is targeted to come on stream in 2012 and will allow importation of 8 bcm per year of gas from Algeria.

Italy is supplied also by the Greenstream pipeline from Libya (8 bcm per year since 2004). Greenstream is being expanded by 3 bcm to 11 bcm as part of a supply agreement between Libya and Italy.

Egypt-Jordan-Syria-Lebanon-Turkey: Arab Gas pipeline

Egyptian gas flows through the Arab gas pipeline reached Syria in March 2008, en route to a link with the Turkish gas network in 2009. The first leg of the pipeline from al-Arish in Egypt to Jordan was completed in 2003, followed by a second leg to northern Jordan. A third leg into central Syria, which will enable small quantities of gas to flow to Lebanon, is expected to commence service in 2008.

Initial capacity on the Arab gas network will be 10 bcm, with commitments from Egypt to supply at least 6.6 bcm per year. However, supplies to Turkey are likely to be limited (current unallocated gas around 1.1 bcm) unless Egyptian volumes increase, or Iraq follows through with an initial agreement to supply gas from the Akkas field on the Syrian border. Syria is currently pursuing a short pipeline from Aleppo to Kilis in Turkey to complete the link via its existing infrastructure into the Turkish and European markets (this will be reversible to facilitate possible Iranian imports from 2009). A larger pipeline from Homs, Syria, to Aleppo is planned for the longer term and will be essential to enable increased volumes to flow through the Syrian gas network into the Turkish, and potentially, European systems.

European interconnectors

France-Spain: MidCat

Several projects to expand internal cross-border capacity in Europe were announced in 2007. France and Spain have announced the construction of a new interconnection between the two countries on the Mediterranean side. The MidCat project (Midi-Cataluña) is intended to provide greater competition in gas supplies as well as adding a potential security back-up between LNG terminals and storage facilities in the two countries. The 150 km pipeline will require additional investment on both sides to upgrade the existing network. MidCat, promoted by the three TSOs of the region, Enagas, TIGF and GRTGaz, is expected to be operational by 2013-2015. By 2015 capacity could reach 13.5 bcm per year northwards and 13.2 bcm per year towards Spain.

Finland-Estonia: Balticconnector

Balticconnector is a regional integration project aiming to link the gas networks of the Baltic countries and Finland. Its purpose is to extend regionally the benefits of the significant underground storage in Latvia (Inčukalns, 2.3 bcm working capacity) while at the same time realise much needed regional integration of gas markets currently dependent on one supply source. Balticconnector will start at Inčukalns in Latvia and will link, through an offshore section of around 100 km, the capital of Estonia, Tallinn, with the Finnish capital Helsinki on the other side of the Gulf of Finland. The total length of the pipeline is estimated at 220 km. It has been suggested that a joint venture of local companies, including Gasum Oy and Gazprom, operate the pipeline. A study project started in 2005 and it is expected that this will be completed by the end of 2009.

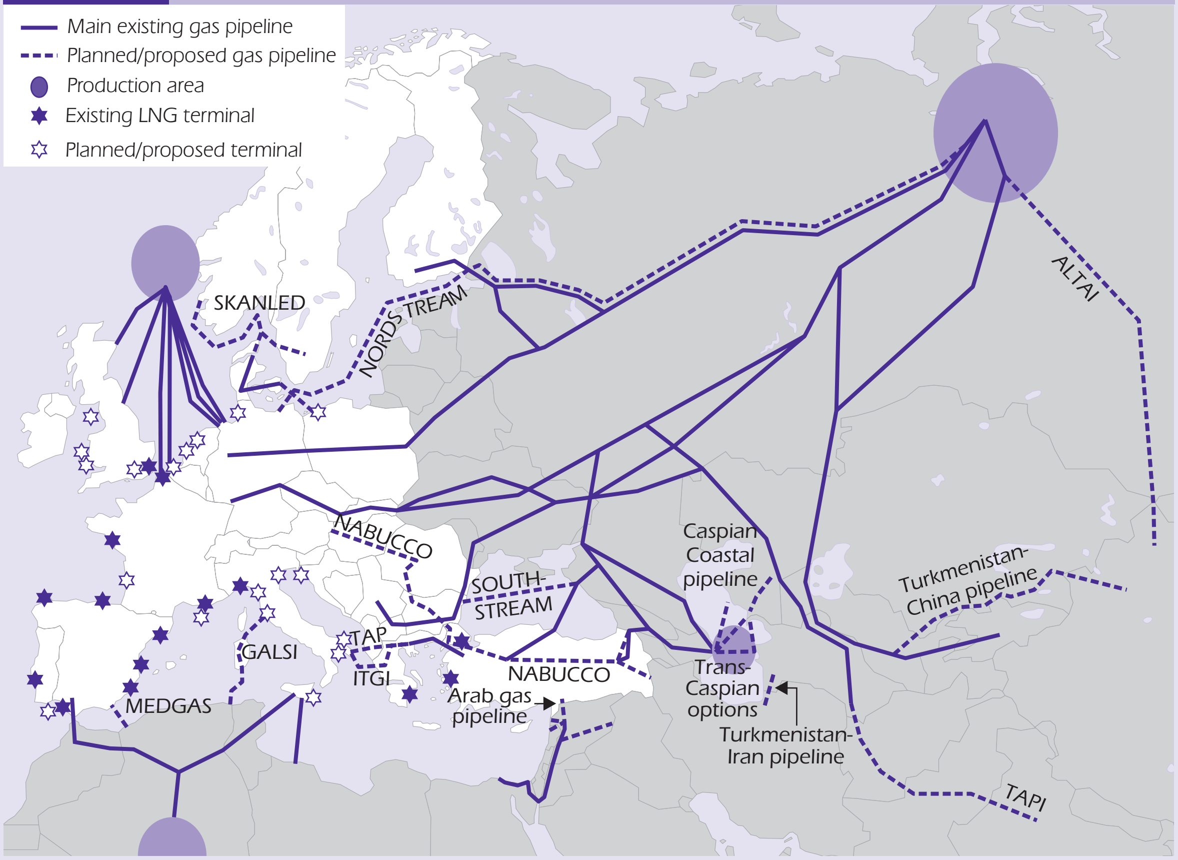
East-European TSOs integration: NETS (New Europe Transmission System)

In Eastern Europe there is a noticeable lack of network integration. Until now, very few proposals have emerged, *e.g.* a pipeline connecting the Romanian and Hungarian gas networks (Arad-Szeged link). The New Europe Transmission System (NETS) initiative is far more ambitious; it consists of the progressive integration of the networks of Hungary, Austria, Slovenia, Croatia, Bosnia-Herzegovina, Serbia, Romania and Bulgaria into one independent regional gas transport company.

The NETS project would operate nearly 27 000 km of pipelines in the region and become the third largest TSO in Europe. Initiated by Hungarian utility MOL, partly as a response to a hostile bid for takeover by rival company OMV of Austria, the plan aims to integrate the small-scale networks in Central and South-Eastern Europe, and to strengthen local operators. An integrated gas transportation network would reinforce both security of supply and gas transport efficiency in the zone.

Even if a single company is not be established for the region, a more coordinated system for gas transportation could help achieve market integration in a region where gas interconnection is at best weak and where security of supply is an issue of growing concern.

Map 4 **Main transmission projects in Eurasia to 2015**



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, company anouncements, media reports.

Table 10 Existing supply pipelines to IEA Europe and new EU Member States

Source	Pipeline	Date of completion	Entry point	Transit through	Owners	Maximum entry capacity (bcm per year)	Total capacity available per source	Estimated average rate of utilisation
Russia	Brotherhood - Eustream	1967/78/84/89	Velke kapucany	Ukraine	Naftogaz	108	223.5	70%
				Slovakia	State 51%; GdF/EON 49%			
				Czech Republic/ Hungary/Austria	RWE Transgas/ MOL/OMV			
	"Balkan transit"	1974/87/88	Isaccea	Ukraine	Naftogaz	37.5		
				Romania	Transgaz			
				Bulgaria	Bulgargaz			
				Greece/Turkey	Desfa/Botas			
	Yamal Europe	1999	Kondratki	Belarus	Gazprom, Beltransgas	33		
				Poland	Gazprom 48%; PGNiG 48%			
				Germany (Jagal)	Wingas			
	Bluestream	2003	Samsun	under Black Sea	Gazprom, Eni 50% each	16		
	Russia-Finland	1973	Imatra	direct to Finland	Gazprom	7		
	Others		Baltic countries, other entry points in Romania and Poland		mainly Gazprom	22		
Libya	Greenstream (+3bcm expansion planned)	2004	Gela	under Mediterranean Sea	Eni 75%	8	8	95%

Source: IEA, GIE, company information.
Note: utilisation rates calculated on the basis of total exports reported to IEA for 2006 divided by total physical capacity for each supply source at the entry point. SCP and Langeled pipelines are not taken into account.

Table 10 Existing supply pipelines to IEA Europe and new EU Member States (continued)

Source	Pipeline	Date of completion	Entry point	Transit through	Owners	Maximum entry capacity (bcm per year)	Total capacity available per source	Estimated average rate of utilisation
Algeria	Transmed (Enrico Mattei) - including recent expansion	1983/94	Mazara del Vallo	Tunisia	TTPC (Eni)	32	43	81%
				under Mediterranean Sea	TMPC (Eni 50%, Sonatrach 50%)			
				Italy	SNAM			
	Maghreb-Europe (Pedro Duran Farell)	1997/2004	Tarifa	Morocco	Sagane	11		
				under Mediterranean Sea	Enagas/Sonatrach/ Moroccan state			
Norway	Norpipe Europipe I Europipe II	1977/1995/ 1999	Emden/ Dornum	direct to Germany	Gassled	43.8	113.4	95%
	Zeepipe	1993	Zeebrugge	direct to Belgium		14.6		
	Franpipe	1998	Dunkerque	direct to France		18.6		
	Vesterled	1978	St Fergus	direct to the UK		12.4		
	Langeled	2007	Easington			24		
Caspian region	SCP	2006	East Turkey	Azerbaijan, Georgia	BP 25,5%, Statoil 25,5%, SOCAR 10%, LUKoil 10%, NICO 10%, Total 10%, TPAO 9%	7.8	17.8	n.a.
	Iran-Turkey	2001		Iran	state ownership	10		
Total entry capacity							**405.7**	

Source: IEA, GIE.
Note: utilisation rates calculated on the basis of total exports reported to IEA for 2006 divided by total physical capacity for each supply source at the entry point. SCP and Langeled pipelines are not taken into account. Norway is considered here as a supplier to Europe.

Table 11 **Projected supply pipelines to IEA Europe and new EU Member States**

Source	Pipeline	Date of completion	Transit/portion	Maximum depth offshore (m)	Lenght (km)	Maximum capacity (bcm per year)	Estimated cost (bn euros)	Shareholders
Russia	Nordstream	2012	under Baltic Sea to Germany	~200	1200	55	8	Gazprom 51%; BASF, EON, Gasunie 16.3% each
	Southstream	2013	under Black Sea to Bulgaria	2200	900	30	13/14	Gazprom, Eni
			Bulgaria		n.a.		n.a.	Gazprom, Bulgargaz 50% each
			Serbia (10 bcm/ year)		400		2	Gazprom
Caspian/ Russia	Nabucco	2011/2012	Turkey, Bulgaria, Romania, Hungary and Austria		3300	31	7	Botas, Bulgargaz, Transgaz, MOL, OMV, RWE - 16.6% each
	ITGI	2007	Turkey-Greece		300	11.5	0.3	Botas in Turkey, Depa in Greece
		2007-2012	Greece		600		0.6	Depa/Desfa
		2011/2012	under Adriatic Sea to Italy (8 bcm/year)	1450	215		0.35	Edison, Depa
	TAP	2011	Greece-Albania		505	10	1.5	EGL, Statoil-Hydro
			under Adriatic Sea to Italy	820	115			

Source: IEA, company information, media reports.

Table 11 Projected supply pipelines to IEA Europe and new EU Member States (continued)

Source	Pipeline	Date of completion	Transit/portion	Maximum depth offshore (m)	Lenght (km)	Maximum capacity (bcm per year)	Estimated cost (bn euros)	Shareholders
Algeria	Galsi	2012	Algeria		640	8	2	Sonatrach 41.6%; Edison 20.8%; Enel 15.6%; Sfirs 11.6%; Hera Trading 10.4%
			Algeria-Sardinia	1950	310			
			Sardinia		300			
			Sardinia-Italy	900	220			
	Medgaz	2009	under Mediterranean Sea to Spain	2160	210	8	0.9	Sonatrach 26.32%; Cepsa 20%; Iberdrola 20%; GdF 12%; Endesa 12%
Norway	Skanled and Baltic pipe	2012	under Skagerrak strait to Denmark/ Sweden	n.a.	n.a.	7	1.2	Skagerak Energi 20 %; E.On Ruhrgas 15 %; PgNiG 15 %; Energinet.dk 10 %; other locals 40%
			Baltic pipe: Denmark to Poland (3.5 bcm/ year)	n.a.	230		0.5	PGNiG 50% Energienet.dk 50%
Total km, added capacity, cost					**9445**	**160.5**	**37-38**	

Source: IEA, company information, media reports.

Strategies of gas producing countries, national oil companies and international oil companies

The strategic importance of the gas and oil sectors in many producing states means that governments often take a dominant role in the management of the resource. Decision making in relation to hydrocarbon resources performed through state-owned oil and gas companies, can therefore be influenced by non-market related factors. Thus, in the Middle East, Africa, Central and South America, Russia and the former Soviet Union, social and widely defined economic and political objectives often play a significant role in decision making within the oil and gas sectors.

Gas producing countries

Some producing countries with large reserves and export plans are placing substantial obligations on foreign investors, discouraging direct investment. In others, internal debate continues as to the amount of gas that should be exported and the volumes that should be allocated to the domestic market to feed both economic growth and support social needs, often at prices well below those prevailing in global markets. In the past, remotely located gas was often considered "stranded", incapable of being brought to markets. LNG markets and growing global demand are rendering this concept obsolete.

In Russia, natural gas accounts for more than 50% of the economy's energy balance with just over 453 bcm consumed domestically in 2006. Historically, prices paid by domestic consumers of natural gas bore only weak links to the cost of producing and delivering the gas and although prices have increased recently, they remain below export prices. The government has committed to increase prices to European export levels, on a netback basis by 2011, at least for industrial customers. Despite this, much remains to be done, particularly in relation to non-industrial consumers. The Russian government has legally established a monopoly on natural gas exports thereby forcing down the prices independent producers can obtain for their gas, which has to be shipped via Gazprom-controlled networks. The result is often reduced incentives to invest in production and continued flaring of much gas. Recently the government has realised the weakness of this policy and moved to address it.

Early in 2008 the Nigerian president, Umaru Yar'Adua, announced plans for new large-scale investment in the country's natural gas and LNG industries which will result in greater exports and increased domestic supply. Nigerian officials claim Nigeria's reserves are big enough to satisfy both export and domestic demand. The president wants to raise USD 20 billion from energy companies to invest in harnessing gas reserves while at the same time solving the country's ongoing power crisis. The new policy, not yet law, promotes unequivocal action to prioritise domestic gas supplies over exports. It has been suggested that the government might require producers to set aside as much as 25%-30% of gas for Nigerian use.

Indonesia appears to be moving to divert gas away from exports to supply domestic economic needs, further raising concerns over supplies to tight global markets. Nevertheless, Indonesia, which was until recently the world's largest producer of LNG, stated in early 2007 that its wish "is to maintain a balance between exports of gas and domestic use of gas". The government claims that this policy could meet the dual objective of fulfilling rising domestic needs while supplying the export market.

Low gas prices have led gas use in Iran to grow rapidly by 46% in the five years to 2007. Continued growth has seen Iran emerge as the number three gas user globally (ahead of Germany and behind the United States and Russia). The recent winter brought a record cold spell and widespread snowstorms in Iran. Government policy of heavily subsidising natural gas for domestic space heating has naturally led to increasing consumption rates while at the same time other policies have limited production from the country's very large gas reserves. Consequently, gas- and oil-rich Iran now imports from Turkmenistan, which reduced supply in February 2008, seemingly for technical reasons, just as cold weather hit. Despite taking drastic measures to reduce consumption, Tehran came within hours of having to shut off gas to much of the city, while supply was totally cut in many provinces and exports to Turkey were cut off as well. Despite Iran's vast gas reserves, it is planning to double imports from Turkmenistan to 14 bcm.

OECD countries are not immune to such practices either. Late in 2006 the Western Australian state government[10] published its domestic gas reservation policy stating their commitment to securing the state's long-term energy needs by ensuring adequate access to domestic gas supplies. Following months of negotiations and private and public discussion, it announced that the equivalent of 15% of production from export gas projects, excluding LNG, will be required to be reserved for domestic use as a condition of access to Western Australian land for the location of processing facilities. The policy is to some extent flexible, allowing negotiations between the state and LNG project promoters to review on a case-by-case basis the means by which domestic gas commitments may be satisfied. This policy is in accordance with the state government's Fuel Diversity in Power Generation Policy and is designed to enhance security of electricity supply. By ensuring the availability of competitively priced gas in the domestic market, the government believes that competitive tension between fuel sources will be maintained. In other IEA countries, environmental policies also restrict access to prospective exploration acreage.

International oil companies

International oil and gas companies (IOCs) lead the global gas business, particularly LNG. They are expected to increase their share of LNG for at least the medium term. An important question is how

10. The vast bulk of Australian gas reserves lie offshore of Western Australia, a vast (more than 2.5 million km²) but sparsely populated (2 million) state.

the international companies can take advantage of their expertise in project development and contribute to increasing and enhancing the gas value chain, particularly as such companies find access to upstream hydrocarbon developments.

The role of IOCs is of interest in understanding markets and investment. Corporate decisions are made with different considerations rather than from a general interest of stable supply. A major company that has gas assets in multiple countries may not want to sell LNG from its Asian projects before its LNG from another production source, *e.g.* in the Middle East, has been sold. Another company may limit investment in its home country because the company, with limited internal capital, prefers to diversify into other markets. Thus, strategies adopted by international companies continue to have significant implications on gas markets.

The fact that IOCs are showing strong financial performance, thanks to higher energy prices, does not necessarily translate into expanding upstream investment, production, nor reserve bases. Development areas are becoming more challenging, both technologically and geopolitically, as resources in easier to access areas have already been developed. Uncertain fiscal regimes and unstable investment environment, in gas producing countries often inhibit companies from spending money. Conversely, some national or state-owned companies are growing internationally while at the same time taking more control in their home countries.

The traditional IOCs face a challenging competitive environment that is eroding their exclusivity. Oil service companies can provide certain comparative expertise and private equity. Sovereign wealth funds, as well as national oil and gas companies in producing countries and emerging consuming countries (China and India), can mobilise cash for project developments. Reflecting the situation, equity holdings of LNG export businesses by IOCs are relatively smaller than those by national oil (and gas) companies (NOCs).

However, IOCs still have something unique to offer in providing integrated project development – combining the most advanced technology and engineering, financial strength, consuming market access and marketing expertise, operating experience and total project management. This unique strength of IOCs looks more effective in gas than in oil and particularly in the complex and capital intensive LNG sector. Hence, they are expected to grow their share in the LNG sector for at least a few more years. Some of these companies have been particularly innovative in developing more flexible marketing arrangements, often serving several major consuming regions from a portfolio of LNG production, responding generally to price signals. This section looks at the activities of major IOCs focussing on the LNG production sector.

Shell

Royal Dutch Shell of the Netherlands and the United Kingdom has a significant position in LNG, including in Brunei, Malaysia, Nigeria, and Oman. The company is the world's largest private-sector producer of LNG (measured in equity holdings in liquefaction facilities).

Reflecting its traditional emphasis on gas, the company's gas and power unit has been successful in establishing its integrated value chain to the company's gas reserves, which are developed by its exploration and production division.

In addition to its stakes in the liquefaction projects mentioned in the LNG section and a one-sixth holding in the Australia's North West Shelf (NWS) project, the company has stakes in four LNG liquefaction trains under construction: two trains on Sakhalin Island in Russia; one big train in Qatar (Qatargas IV); and the fifth train of the North West Shelf (NWS) project. It also has an indirect stake in the Pluto project in Australia through a 34% holding in Woodside (itself likely to emerge as a major LNG producer by

Table 12 Distribution of LNG export capacity by type of company (in bcm)

	International	National	Others	Total
Operational as of April 2008	85 30.1%	165 58.1%	33 11.8%	284
FID as of April 2008 (likely by 2012)	129 32.1%	226 56.1%	48 11.8%	403

Note: Nominal LNG export capacity at the liquefaction end, distributed according to equity holdings.
International = International oil and gas companies.
National = National oil and gas companies with LNG export capacity in their own countries, excluding those with LNG export capacity only abroad but none in their home countries.
Others = Trading houses, LNG importers, financial institutions, local companies, etc. National oil and gas companies that do not have LNG export capacity in their home countries are included in this category.

Table 13 Top LNG export capacity holders as of April 2008 and likely by 2012

International oil and gas companies			National oil and gas companies		
	2008	2012		2008	2012
Shell	19.3	27.4	Pertamina (Indonesia)	39.6	39.6
BP	15.3	17.3	Qatar Petroleum	27.8	71.7
BG	9.7	9.7	Sonatrach (Algeria)	27.8	33.9
ExxonMobil	9.3	20.8	Petronas (Malaysia)	25.4	26.5
Total	7.9	14.6	NNPC (Nigeria)	14.8	14.8
Eni	6.3	7.3	StatoilHydro (Norway)	1.9	1.9
Repsol / Gas Natural	4.7	5.9	Gazprom	-	6.5
ConocoPhillips	4.0	7.2			
Marathon	3.4	3.4			
Woodside	2.7	9.6			
Chevron	2.7	6.3			

Unit: bcm per year
Note: Nominal LNG export capacity at the liquefaction end, distributed according to equity holdings. 2012 is chosen to show the expected capacity based on the projects for which final investment decisions have been made.

2012). Shell has also acquired an interest in one of the eastern Australia's coal seam methane (CSM) based LNG schemes.

Shell also has had leading roles in developing new markets, including India and Mexico where it has constructed terminals to receive equity LNG, as well as emerging LNG markets in Brazil and Dubai. It also plans to install a receiving terminal on the east coast of the United States. Broadwater LNG, co-owned by Shell and TransCanada, was approved by the Federal Energy Regulatory Commission in March 2008, although the fate of the project is still uncertain as it is waiting for operating permits from the state of New York. Shell also has capacity rights at third party terminals: Cove Point, Maryland, Elba Island, Georgia, and Costa Azul, Baja California, Mexico. It revealed a plan to build a receiving terminal on the Mediterranean coast of France as well. Shell also has indirect interests in two terminals planned in Germany.

In addition, Shell is active in deploying its new technologies including gas-to-liquid (GTL), and floating LNG (FLNG) concepts. After operating a relatively small scale (14 700 b/d) GTL plant next to its LNG plant in Sarawak, in Malaysia since 1993, Shell is now constructing a much larger 140 000 b/d Pearl GTL plant in Qatar in a joint venture with Qatar Petroleum (QP). Having such a wide-variety of solutions for monetising gas enables Shell to be a development partner in many gas producing countries.

BP

BP of the United Kingdom is a global LNG company maintaining the second largest LNG export capacity amongst the IOCs. It has taken a selective approach, having exited Qatar in 1992, acquired a major role in Trinidad, launched the Tangguh project in Indonesia, and is feedgas provider of the existing Bontang LNG plant in East Kalimantan (Indonesia) through the Vico joint venture with Eni. Many of the stakes were acquired through the company's takeovers of Amoco and Arco in the past 10 years. Elsewhere, BP has minority interests in LNG projects in Abu Dhabi (Das), Australia (North West Shelf), and the recently sanctioned Angola LNG. The company also has major upstream gas interests in Algeria, where the company started the 9 bcm per year In Salah project in 2004, and Alaska, where currently North Slope gas is reinjected to enhance oil production. The company gave up an upstream stake in the Kovykta gas field in Eastern Siberia, Russia in 2007.

After gaining access to LNG production in Trinidad, the company has been active in establishing its position in regasification as well, acquiring capacity at the Cove Point terminal in Maryland (United States) in 2003, and Isle of Grain in the United Kingdom in 2005. The company is also planning to install its own LNG terminals in the United States, although unsuccessfully so far. It has shares in receiving terminals in Spain and China as well.

Total

Total of France has quietly become a global LNG player with minority positions in many projects. The company is particularly strong in the Middle East and has assumed an operator role for the first time in Yemen's first LNG project, after having minority stakes in all of the existing LNG exporting countries in the Middle East, as well as

Nigeria and Norway. Based on the expected success of its first operator role in Yemen, with fellow French EPC contractor Technip, Total is pursuing other LNG projects including the Shtokman LNG project in Russia and Pars LNG project in Iran.

In West Africa, Total took over Chevron's 17% interest in the Brass LNG project in Nigeria in 2006, and has a 13.6% stake in the Angola LNG project, which announced a final investment decision (FID) in December 2007. In the Asia Pacific, Total joined Japan's Inpex in the Ichthys LNG project in Western Australia. Total is also the largest feedgas supplier to the existing Bontang LNG plant in Indonesia's East Kalimantan. The company also provides about 10% of feedgas to the Brunei LNG plants.

While expanding its portfolio LNG supply base, the company is also active in gaining access to markets. In addition to its home country, where the company has a minority share in the Fos Cavaou terminal (near Marseille) under construction, the company has stakes in receiving terminals in India and Mexico. The company has a significant capacity right in the United States at the Sabine Pass receiving terminal which opened in Louisiana in April 2008. The company also has a 25.58% shareholding in the proposed Krk Island LNG receiving terminal in Croatia.

ExxonMobil

ExxonMobil of the United States enjoys huge success in LNG in Qatar from the legacy of Mobil. The company is developing massive liquefaction capacity in the country in joint ventures with Qatar Petroleum (QP), more than doubling its equity production capacity from current 9.4 bcm per year to 21 bcm in 2011. The ExxonMobil-QP duo is developing receiving terminals in the United States, United Kingdom, and Italy, each due to open in 2008.

The company is apparently taking a cautious approach in spearheading development elsewhere. As the Indonesian government viewed ExxonMobil had not done enough to develop the Natuna D-Alpha block, the state company Pertamina is seeking new partners for the project in 2008. ExxonMobil exited the Angola LNG project in February 2007, ten months before the final investment decision in December.

ExxonMobil has a 41.6% stake and operatorship in a nascent LNG export project in Papua New Guinea. It is also a 25% partner in the planned Gorgon LNG project in Australia. The company has a 30% stake and operatorship in the Sakhalin I project in Russia's Pacific Coast, which could supply pipeline gas or LNG, depending on market conditions. ExxonMobil revealed an LNG receiving terminal project offshore New Jersey, the United States, targeting a middle of next decade start. This is its first attempt to establish an LNG value chain outside of its partnership with Qatar since exiting from Angola LNG.

Chevron

Chevron of the United States has a one sixth stake in the North West Shelf in Australia, and feedgas production to the Bontang LNG plant in Indonesia from its Unocal acquisition. Chevron is the largest foreign operator of oil production in Indonesia. The company has only a minor involvement in existing LNG production.

Chevron has given up several high profile LNG initiatives, including the Port Pelican receiving terminal plan offshore Louisiana, United States, the Coronado receiving terminal plan offshore Baja California, Mexico, and the proposed Brass LNG export project in Nigeria, where the company's 17% interest was transferred to Total in 2006. However, the company made a breakthrough in December 2007, when a final investment decision (FID) was made for Angola LNG, in which the company has a 36.4% stake and the lead role.

Chevron is now in critical periods leading up to possible approval for the Gorgon LNG project in Australia, a joint venture with Shell and ExxonMobil, and the Sabine Pass receiving terminal project in the United States, where Chevron has a 10.3 bcm per year regasification capacity, which could well be underutilised for some years. As Chevron is the largest holder of undeveloped natural gas resources in Australia, potentially amongst the biggest unexploited gas reserves left within OECD countries, the company announced in March 2008 that it would also develop its Wheatstone gas field for another LNG plant.

In addition to participation in the OK LNG project and exit from Brass LNG in 2006, the company is leading the West Africa Gas Pipeline (WAGP) project in Nigeria, which is to supply mainly associated gas produced in Nigeria's western delta to neighbouring Ghana, Togo and Benin from mid-2008. The company's 34 000 b/d Escravos GTL joint venture with Sasol in Nigeria has slipped from the original target of 2005 to at least until 2010.

Eni

Eni of Italy is active in international upstream development and pipelines, as well as minor LNG positions in the Bontang LNG project through the Vico joint venture with BP, Nigeria LNG, Segas in Egypt, Darwin LNG in Australia, and Qalhat LNG in Oman. Eni participates in projects in Egypt and Oman through a joint venture with Union Fenosa of Spain, Union Fenosa Gas, which could also have a 5% stake in the proposed second train at the Equatorial Guinea LNG project.

Eni also has 13.6% of the recently sanctioned Angola LNG, as well as the proposed Brass LNG project in Nigeria. The company has been the biggest foreign gas and oil operator in Libya even during the years when tough international sanctions were imposed on the country. It signed a wide-ranging agreement with Libya's NOC in October 2007, which includes a plan to develop a 5 bcm per year LNG export plant at Mellitah in 10 years, as well as a 3 bcm per year capacity addition to the existing 8 bcm per year Greenstream pipeline to Italy.

ConocoPhillips

ConocoPhillips of the United States is also very active in LNG, including the Kenai project in Alaska, the oldest project in the Pacific region, the Darwin LNG project in Australia, the Qatargas III mega train project under construction, and the proposed Brass LNG in Nigeria and some receiving terminal deals in the United States and Europe, although it has failed to acquire stakes in Shtokman. Its large LNG receiving terminal in Freeport, Texas, which opened in April 2008, may be underutilised due to lack of long-term committed LNG supply. Output from the Qatargas III supply, which the company originally intended to deliver to the Freeport terminal, is now likely to be shipped to the Golden Pass terminal, also in Texas, being developed by Qatar Petroleum (QP), ExxonMobil, and ConocoPhillips.

Marathon Oil

Marathon Oil of the United States, who is also a partner in the Alaska LNG project, gained LNG supplier status in the Atlantic region in Equatorial Guinea LNG. The company was not successful in developing a regasification terminal in Baja California, Mexico, early in this decade. It was once a lead partner in Sakhalin II, before the company's stake was sold to Shell in the middle of 1990s and the project took shape.

BG Group

BG Group of the United Kingdom is the first mover in several areas of the global LNG business including firm capacity holding in the United States, portfolio supply building with flexible destinations, and secondary marketing of LNG. The company is the largest importer of LNG in the United States, providing 55%, or about 12 bcm, of LNG supplied to the United States in 2007.

The company is expanding from the Atlantic into Pacific LNG marketing, not only by diverting short-term cargoes from the former to the latter, but also by establishing long-term market access in Chile, Hong Kong, and Singapore, and supply sources in eastern Australia from coal-seam methane (CSM). In addition to the current long-term LNG offtake commitments from Trinidad, Egypt, Equatorial Guinea and Nigeria, the company is likely to source LNG from Nigeria's NLNG Train 7, the Australian coal-seam methane (CSM) LNG project, OK LNG and Brass LNG in Nigeria, and possible new Egyptian and Trinidad trains. Among them, BG has equity holdings in the projects in Trinidad, Egypt, and the proposed OK LNG and the CSM LNG projects.

Gas Natural/Repsol

The Gas Natural/Repsol duo of Spain has mainly focussed on Latin American and Southern European countries, including Spain, Italy, Trinidad, Peru, and Mexico. Repsol is now developing a receiving terminal in eastern Canada which is due to open in 2008, enabling the two companies to have more flexible market access on both sides of the Atlantic Ocean. Repsol has committed to buy all the planned output from Peru LNG, the first LNG export project from Pacific Latin America, in which the company also has 20% equity. The company will supply most of its Peru LNG to the planned Manzanillo terminal on the Pacific central coast of Mexico, after its own Lázaro Cárdenas plan failed. The company is considering directing a smaller portion of Peruvian LNG production to Asia, subject to pricing arrangements.

Woodside

Woodside of Australia, building on its success as the operator of the North West Shelf LNG venture, is expanding its LNG portfolio by developing more projects in the country. The company took a final investment decision (FID) on the Pluto LNG project in July 2007. The production is expected to start in 2010, allowing the company to have more flexible LNG supply. The company floated an idea for a Burrup LNG Park for expansion to process its own and third party gas reserves in the area. Woodside has signed preliminary agreements to sell LNG to China's PetroChina and Chinese Taipei's CPC from the Browse Basin gas reserves, showing its aggressive marketing strategy even before securing an agreement of all partners in the reserves. The development also depends on a governmental study that started in 2008 on the appropriateness of the site of the LNG project.

StatoilHydro

A major player in the European pipeline gas supply business, StatoilHydro is expanding its LNG assets by starting up the Snøhvit LNG project in its home country, Norway, acquiring receiving capacity in North America, and entering the Shtokman development project in Russia. The company is acquiring upstream stakes in other producing countries as well, including Algeria and Nigeria.

"International" national oil (and gas) companies

Other "international" national (state-owned) oil (and gas) companies are also trying to expand into downstream markets, based on their home success in developing LNG export projects. Some examples include the following:

Petronas of Malaysia is a 35.5% equity holder of an LNG export plant in Egypt, aiming at supplying its own and third parties' receiving terminals, in addition to the company's majority holdings in its home country's gas and LNG business. It also bought an interest in Gladstone LNG, based on CSM resources in eastern Australia.

Qatar Petroleum (QP) is developing receiving terminals in the United States, the United Kingdom and continental Europe in parallel with its mega liquefaction train development projects.

Sonangol of Angola is seeking to secure flexibility in outlets, and to have better control of marketing by participating in a terminal development project in the United States.

Sonatrach of Algeria is undertaking two LNG projects alone and working with foreign partners on the development of 23 bcm of new pipeline capacity. Algeria is pressing importing countries to give Sonatrach direct access to their domestic markets in return for a share in developing Algeria's gas reserves.

European utility companies

The European utility competition for LNG has become truly international. The **GdF-Suez** merger forms an even stronger group in LNG with significant receiving capacities on both sides of the Atlantic Ocean, American Continent and even footholds in Asia (India's Petronet and the planned LNG terminal in Singapore).

Électricité de France (**EdF**) has already acquired LNG receiving capacity in Belgium and access to Qatari supply, as well as future receiving capacity in Italy through

Table 14 IOCs: major holdings in LNG and major export projects

	Lead role LNG export Other major export projects	Participation LNG export Other major projects	LNG regasification Terminal equity and capacity
Shell	Brunei LNG Malaysia LNG Nigeria LNG Oman LNG Sakhalin II, Russia (Now Gazprom) Persian LNG, Iran Pearl GTL, Qatar	North West Shelf, Australia Qatargas IV Gorgon, Australia Greater Sunrise OK LNG, Nigeria Fisherman's Landing CSM LNG	Altamira, Mexico Hazira, India Broadwater, New York Fos III, South France Cove Point, Maryland Elba Island, Georgia Costa Azul, Mexico
Total	Yemen LNG Shtokman (Technical), Russia Pars LNG, Iran	Bontang, Indonesia Brunei LNG Abu Dhabi, Oman Snøhvit, Norway Nigeria LNG Angola LNG Brass LNG, Nigeria	Fos Cavaou, South France Altamira, Mexico Hazira, India Sabine Pass, Louisiana South Hook, Wales Krk Island, Croatia
BP	Tangguh, Indonesia	Abu Dhabi North West Shelf Bontang, Indonesia	Crown Landing, New Jersey Cove Point, Maryland Isle of Grain, England Bilbao, Spain Guangdong Dapeng, China
ExxonMobil	Qatargas I, II, RasGas Arun, Indonesia Papua New Guinea	Gorgon, Australia Exited Angola LNG (Still to supply feedgas)	Zeebrugge, Belgium South Hook, Wales Golden Pass, Texas Rovigo, Italy BlueOcean, New Jersey
Chevron	Angola LNG Gorgon Wheatstone West Africa Gas Pipeline (WAGP) Escravos GTL, Nigeria	North West Shelf, Australia OK LNG, Nigeria Exited Brass LNG, Nigeria	Sabine Pass, Louisiana Pascagoula, Mississippi
Eni	Possibly in Libya	Segas, Egypt Qalhat, Oman Darwin LNG, Australia Brass LNG, Nigeria South Stream pipeline from Russia	Panigaglia, Italy Spain via Union Fenosa Gas Pascagoula, Mississippi Cameron, Louisiana
ConocoPhillips	Kenai, Alaska Darwin, Australia	Qatargas III Brass LNG, Nigeria Greater Sunrise	Freeport, Texas Golden Pass, Texas Some in Europe
Marathon	Equatorial Guinea LNG Exited Sakhalin II in 1990s	Kenai, Alaska	Elba Island, Georgia Failed in Baja California, Mexico
BG	Egyptian LNG CSM LNG, Australia	Atlantic LNG, Trinidad Purchasing the entire output from Equatorial Guinea LNG OK LNG, Nigeria Tupi fields, Brazil (25%)	Lake Charles, Elba Island in the United States, Dragon, Wales, Brindisi, Italy Quintero, Chile Singapore

Source: Company information

Table 14 IOCs: major holdings in LNG and major export projects (continued)

	Lead role LNG export Other major export projects	Participation LNG export Other major projects	LNG regasification Terminal equity and capacity
Repsol / Gas Natural	Peru LNG	Atlantic LNG, Trinidad Persian LNG, Iran Failed in Gassi Touil, Algeria	Spanish terminals Canaport, Canada Puerto Rico
Woodside	North West Shelf Pluto Browse Basin Greater Sunrise		Terminal project off California
StatoilHydro	Snøhvit	Shtokman, Russia Interests in Nigeria, Brazil, Venezuela	Cove Point, Maryland

Source: Company information.

Table 15 European utilities' strategies: extending arms from downstream to upstream

	Infrastructure	Upstream and LNG
GdF - Suez	Terminals in France, Belgium, India, Massachusetts, Chile, Canada, Singapore	Egyptian LNG Train 1 (5%) Snøhvit (12%), Trinidad Train 1 (10%) LNG procurement from various sources
EdF	Dunkerque terminal plan Capacity at Zeebrugge LNG terminal	LNG procurement from Qatar
E.ON	Wilhelmshaven terminal plan (78%) Krk terminal plan (31.15%) Le Havre terminal plan (24.5%) Livorno terminal (30.5%, from Endesa) Isle of Grain 1.7 bcm per year capacity from 2010 Nord Stream pipeline (20%)	5% stake in proposed Train 2 of Equatorial Guinea LNG Possible LNG purchase from Pars LNG in Iran
RWE	Wilhelmshaven GasPort Krk terminal plan (31.15%) Excelerate (50%)	Snøhvit Egypt

Source: Company information.

its Edison subsidiary. It is also developing an LNG terminal in France. It needs gas-fired power to supplement its massive base-load nuclear fleet.

E.ON of Germany, who acquired Ruhrgas in 2003, is now eager to enter the LNG business in its home country, the United Kingdom, France and Croatia. Spain's Endesa's 30.5% stake in Livorno LNG receiving terminal project in Italy should also be handed over to E.ON shortly, as Endesa's new owners – Italy's Enel and Spain's Acciona – agreed to sell Italian and French assets to E.ON when it gave up its takeover battle for Endesa in 2007. It is also active on the pipeline gas front, developing a direct connection with Russia via the Nord Stream pipeline project.

Another German gas and power company **RWE** is also active trying to expand into LNG. In addition to a small equity stake in Norway's Snøhvit LNG project, the company has upstream stakes in Egypt and Nigeria that could in the future feed LNG trains. RWE announced that it would purchase 50% of Excelerate Energy of the United States, who has been active in LNG regasification and trading business in recent years with its proprietary "Energy Bridge" onboard regasification application. RWE recently became the sixth partner in the Nabucco pipeline project.

GAS FOR POWER

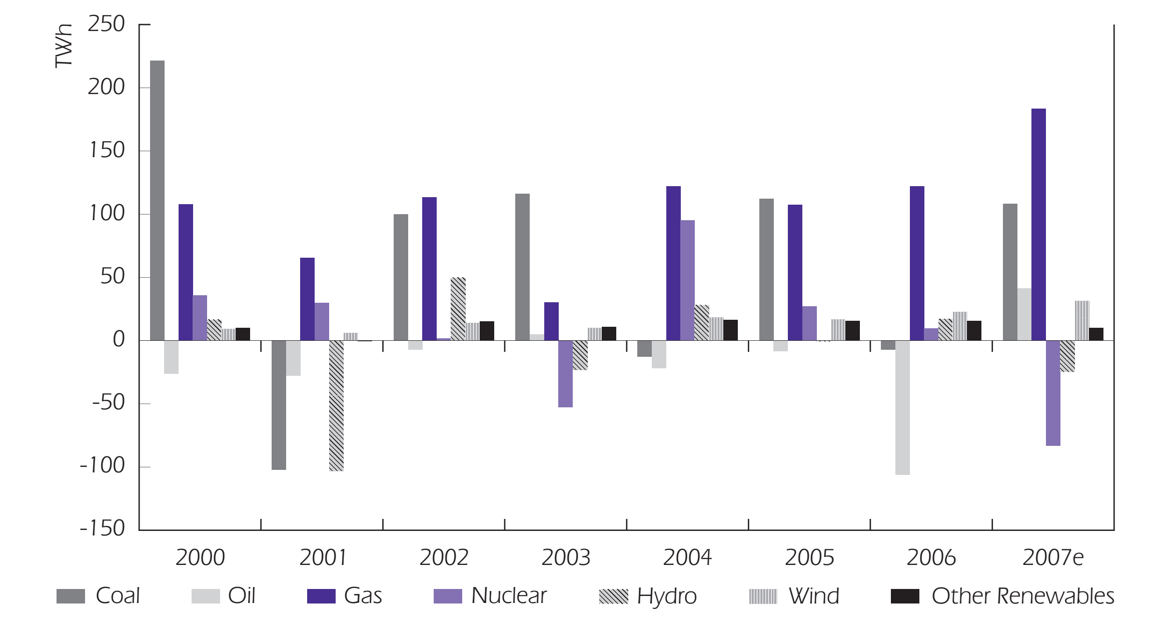
Gas-fired power continues to be the main supplier of incremental power in OECD countries and the major factor underpinning the outlook for gas demand within the OECD. Total power generation in OECD increased by 266 TWh from 2006 to 2007 (of which gas was 184 TWh). Gas and to a lesser extent wind power are the only sources that consistently contributed to increasing power generation capacity since 2000. Power generation from oil decreased from 2005 to 2006, a period that also saw marked increases in oil prices. Power generation output from coal saw a slight decrease in OECD countries from 2005 to 2006, which coincided with price increases in global coal markets. The United States, Japan and Canada were the main contributors to this reduction. Natural gas for power generation has increased consistently in importance, despite rising gas prices.

Evolution of gas-fired power in OECD countries

The share of gas-fired power generation out of total generation increased from 2005 to 2006 in most of the largest OECD countries. The United Kingdom is one of the main exceptions as sharp price increases in 2006 eroded the gas share in favour of coal. OECD gas demand for power generation in the first half of the decade grew by nearly 30 bcm in North America and 37 bcm in Europe.

2007 saw almost a 10% increase in the gas demand for power in the United States. Gas use in the Japanese power sector in 2007 grew by 13% to 56 bcm, due also to lower nuclear and hydro output. The share of gas in power generation in Japan is forecast to grow from 23% in 2006 to

Figure 13 Changes in power generation by fuel source in OECD



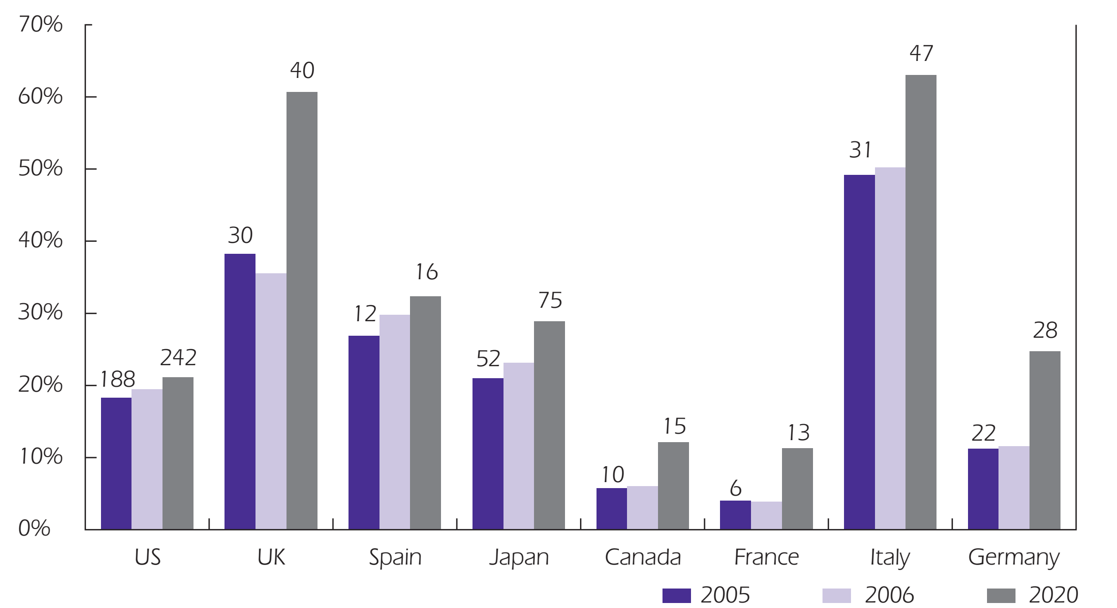
Source: IEA.
Note: 2007 numbers are "best estimates".

29% in 2030, or more than 50% in absolute terms to 385 TWh. In the United Kingdom preliminary data also show that the share of gas-fired power generation increased again to 41.5% in 2007. This increase brought gas demand for power generation in the United Kingdom to 34 bcm in 2007, more than a third of national use. All larger OECD countries foresee that gas demand for power generation will continue to increase considerably to meet strong electricity demand and to replace other electricity sources. For the EU as a whole, gas-fired power looks likely to move from 16% in 2000 to 25% by 2010. This trend is not surprising, given no nuclear construction for more than two decades in North America and OECD Europe (two plants are now being built in the latter) and the delay in construction of new coal plants in Europe. This in turn is the result of NIMBY[11] issues and the regulatory uncertainty regarding energy activities, for example the future treatment of greenhouse gases, especially carbon dioxide (CO_2).

Impact of higher gas prices

Gas price increases have contributed to the considerable increases in electricity prices in several OECD countries. Electricity prices are driven by several factors, often

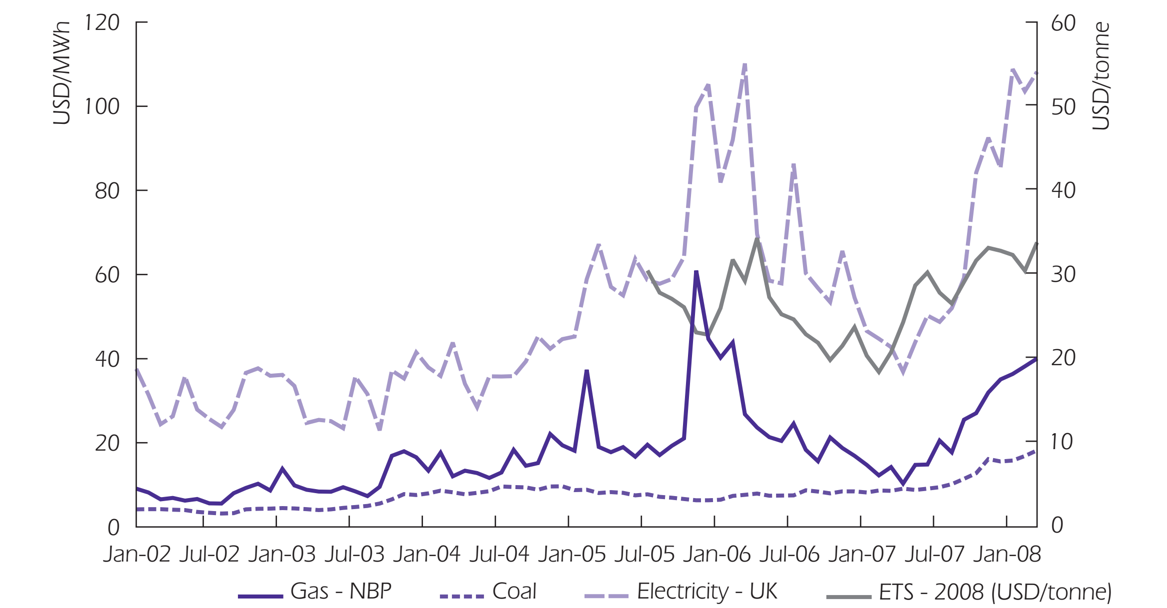
Figure 14 **Gas-fired power generation shares of total generation and gas demand for power generation**



Source: IEA data and forecasts from national government submissions.
Note: bcm on top of bars.

11. "Not In My Back Yard." A common term used to describe resistance to new industrial development in close proximity to populated areas.

Figure 15 **Monthly average prices of gas and electricity in the United Kingdom, coal, and CO_2 emissions in the EU ETS**



Source: McCloskey Coal, Reuters, Elexon, ECX, BlueNext and Mission Climat de la Caisse des Dépôts.

many of them local. Electricity prices have in general been on an increasing trend since 2004 and 2005 in many OECD countries, and fuel cost increases are important drivers, along with CO_2 costs where applicable.

Figure 15 illustrates prices for electricity and gas in the United Kingdom, together with prices for coal, and CO_2 emissions under the European Union Emission Trading Scheme (EU ETS). There are strong correlations between electricity, fuel and CO_2 emission prices.

Another important driver for the upward trend in electricity prices is the need for new investments; to replace ageing plants, to meet increasing electricity demand, and to shift the portfolio of generation plants to one with a smaller environmental footprint. Gas-fired power plants continue to be the technology of choice in this on-going investment cycle in OECD countries. Policy uncertainty, especially with respect to climate change, favours low capital cost and short lead-time, making gas the short term default option for new investment in many OECD countries.

Outlook for new projects

Gas-fired generation is still the technology considered by investors most frequently, and even more often the technology that progresses to actual construction. This trend is partly offset by an increase in the share of coal plants under construction from 14% to 25% of all plants under construction. The share of gas plants under construction has decreased from 57% to 46% of all plants under construction between 2005 and 2007.

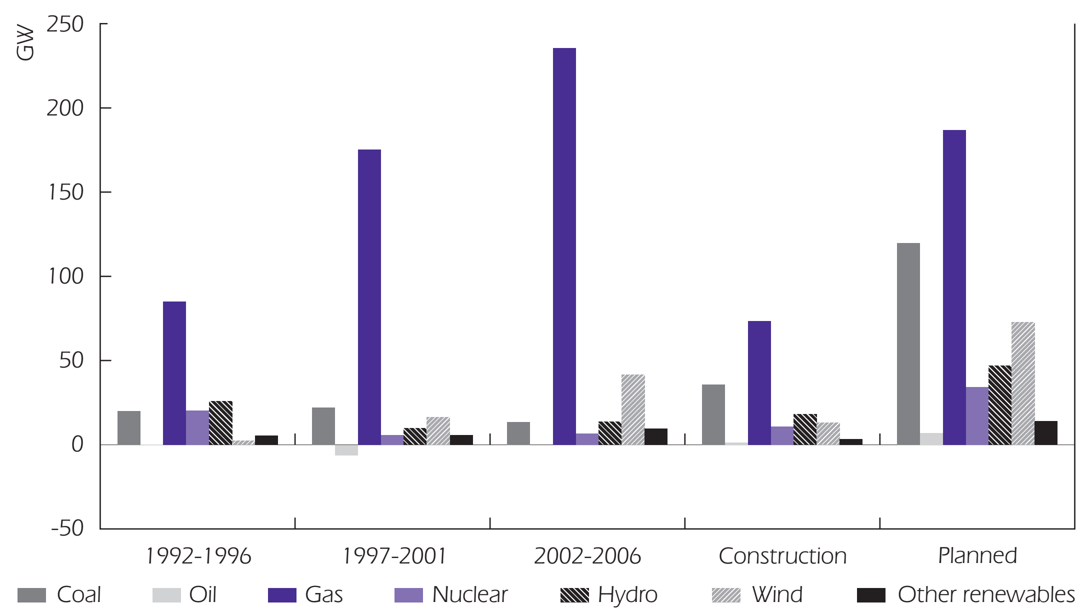
However, even if more coal projects are advancing to actual construction, there is still a large share of planned coal plants that are advancing slowly. During 2007 and 2008 there have also been frequent reports of planned coal projects being cancelled, for example in the United States and Germany.

While many more countries are actively planning new nuclear plants, the lead times on building these plants mean that they will not enter service until after 2015, and possibly well after that time.

The role of wind power is set to increase considerably, contributing to 7% of all capacity under construction and to 15% of planned plants. The role of wind power is likely to be even stronger since wind power projects are often small and develop faster than conventional large scale power plants. However, capacity factors for wind power are considerably lower than most conventional thermal plants, so capacity expansion of wind power does not reflect the contribution of wind in meeting actual electricity demand. For example in Germany, the wind fleet of 21 GW (about one sixth of capacity) generates 40 GWh (around 6% of production in 2007).

The increasing role of gas-fired power generation is particularly marked in Europe. National policies in some European countries are strong drivers for this

Figure 16 **Changes in power generation by fuel source in OECD**



Sources: IEA, Platts, GWEC.

development, such as the politically determined early phase-out of nuclear power in Spain and Germany. Even more important are the policies of the European Union. A comprehensive policy package was agreed on in 2007, leading to proposals for new EU legislation and measures from the European Commission. These include binding targets to reduce CO_2 emissions by 20%, increase the share of renewable energy to 20% and a non-binding target to reduce energy consumption by 20% below a baseline scenario, all by 2020. Gas-fired power is likely to play important roles in all targets, providing a continued strong driver for gas-fired power generation in Europe. Switching from coal-fired to gas-fired power generation is often one of the cheapest options to reduce CO_2 emissions in the near term, depending on gas and coal prices.

Gas-fired power generation is a flexible resource, first of all in terms of finance and construction. Several new combined cycle gas turbines (CCGT) plant designs also allow for flexibility in operation, at a cost in terms of investment and loss of efficiency. This flexibility makes CCGT a necessary component in balancing and integrating more variable resources such as wind power, as the shares of these new renewable technologies increase. Cogeneration of electricity and heat for industry use and for district heating is an important component in meeting the energy efficiency target, and gas is often the fuel of choice in CHP stations.

This section has concentrated on power trends in the North American and European power sectors which are discussed further in the OECD section. In a number of oil and gas producing countries, gas is the fuel of choice for power generation – Nigeria, Middle East, and in Russia. Of course, in the major emerging economies of China and India, coal is the fuel of choice for power generation, as discussed in the World Energy Outlook 2007 (IEA). This might not preclude gas use in power generation in regions where coal supplies are distant, or where air quality is a concern, such as dense cities. While the percentage of gas in the generation mix might be small, in absolute terms it could be very significant for global gas use and trade.

LIQUEFIED NATURAL GAS

Recent developments in LNG markets

Overview

World LNG production in 2007 grew by 9% to 233 bcm, continuing the strong growth that has seen output increase by around 53% in five years. Based on the nominal liquefaction capacity of 256 bcm per year as of the end of 2007, capacity utilisation rate at the liquefaction end was 91%.

An unprecedented major expansion is underway globally in both liquefaction and regasification facilities. Some 80 bcm per year of liquefaction capacity is planned to be added in 2007, 2008, and early 2009, representing a 30% increase and taking the global liquefaction capacity to 330 bcm per year. In the regasification side, an even larger 180 bcm is to come online during the next two years or so, expanding the global capacity by a third to more than 700 bcm per year. As the expansion is unbalanced, regasification capacity is likely to be underutilised relative to liquefaction.

The expansion seems unlikely to unfold as planned and scheduled. There are indications of project delays across the industry caused by shortage of skilled labour and higher material and engineering costs. Even when projects start operations, initial troubles, as well as occasional shortages of feedgas, often prevent them from producing at design capacity for a prolonged period. Having production capacity no longer means actual production is there, as was the case 10 years ago.

After only one final investment decision (FID) was made in LNG production in 2006 for Peru LNG (6 bcm per year from 2010), which was revealed in January 2007, three such decisions were made in

Table 16 Unprecedented expansion of the LNG industry

	Liquefaction	Regasification
2007	RasGas II 5 (6.4 bcm), Equatorial Guinea (4.6)	Mugardos (3.6), Revithoussa (3.8), Teesside (4.0), Pyongtaek 2 (4.3)
2007-08*	Snøhvit (5.6), Nigeria 6 (5.6)	Zeebrugge+ (4.5), Northeast Gateway (4.1),
2008-09**	NWS 5 (6.0), Qatar (21.2), Sakhalin (13.1), Tangguh (10.3), Yemen (4.6)	Spain (4.4), Rovigo (8.0), Dragon (6.0), South Hook (10.6), Grain (8.7), Pyongtaek 2+ (4.3), Taichung (4.1), China (6.9), Dahej+ (8.2), Brazil (4.8), Cove Point+ (8.3), Cameron (15.5), Freeport (15.5), Sabine Pass (26.9), Canaport (10.3), Costa Azul (10.3), Fos II (8.3), Bahía Blanca (1.5)
Size	+80 bcm (60 million tonnes) per year in two years = +30% --> 330 bcm per year	+180 bcm per year in two years = +30%-35% --> More than 700 bcm per year

Source: Company information.
Notes: 2007-08* = Projects targeting 2007 - early 2008 start; 2008-09** = Projects targeting 2008 - early 2009 start.

Table 17 Start-up delays in LNG production projects

Project	Incident	Consequence
Snøhvit (Norway)	Heat exchanger leak	Only two cargoes in 2007, reduced output in 2008
Equatorial Guinea	Heat exchanger leak	Six week outage in October 2007 (missing seven cargoes)
Nigeria LNG 6	Gas field delay	Missed end 2007 target of the first delivery
North West Shelf	Electrical trouble	Third unplanned outage in three years
Segas (Egypt)	Feedgas shortage	Below-capacity output
Qalhat (Oman)	Feedgas shortage	Below-capacity output
Sakhalin II	Feedgas pipeline delay	Possible delay in start until 2009
Qatar mega trains	Construction delay Unknown scale	Several-month delays (Qatargas II-4 3Q 2008, RasGas III-6 1Q 2009)

Source: Company information.

2007 - Pluto LNG in Australia (6.5 bcm per year from 2010), the Skikda replacement train in Algeria (6.1 bcm per year from 2011), and Angola LNG (7.1 bcm per year from 2012). Taking into account capacity reduction in Indonesia and Alaska, and additions in Qatar, liquefaction capacity should increase by another 60 bcm by 2012, assuming the plans materialise as scheduled, to close to 400 bcm (compared with 150 bcm in 2002).

"Global" exchanges of LNG cargoes were accelerated, particularly from the Atlantic to Pacific regions, thanks to dynamic gas price movements during the year. The movement is sometimes called "diversion" as cargoes are transported to destinations different from the originally assumed ones. The "diversion" sales are sometimes carried out under short-term contracts or under spot transactions, and are not necessarily limited in an eastward direction to Asia; trade also happens in the Atlantic markets.

Table 18 Final investment decisions (FIDs) for LNG liquefaction projects in 2006 and 2007

	Capacity, start	Markets	Status
Peru LNG	6 bcm per year, 2010	Mexico, Asia	Final investment decision in 2006; construction
Pluto (Australia)	6.5 bcm per year, 2010	Japan, Pacific	Final investment decision in 2007; construction
Skikda (Algeria)	6.1 bcm per year, 2011	Atlantic	Construction contract in 2007; construction
Angola	7.2 bcm per year, 2012	United States	Final investment decision in 2007; construction

Source: Company information.

Qatar surpassed Indonesia as the world's largest LNG exporter in 2006. It continues to solidify its position by ramping up the 6.4 bcm per year RasGas II liquefaction Train 5 since the beginning of 2007 and adding six mega trains of 10.6 bcm per year capacity each from 2008 to 2011. Although there are signs of delays in construction and possible cost overruns. Qatar exported 40 bcm of LNG in 2007, followed by Malaysia's 31 bcm and Indonesia's 28 bcm.

In addition to RasGas II Train 5, Equatorial Guinea started LNG production in May 2007. Norway's Snøhvit - Europe and Arctic's first LNG export project - exported two cargoes in October 2007, after which the plant was temporarily shut down due to technical problems; it started again in February 2008. Nigeria LNG's Train 6 was completed in December 2007 and was ready for the first shipment in April 2008. Production problems in the early stage of operations have become common in LNG liquefaction projects. Not only decision making delays, but also construction, implementation, and commissioning delays are becoming commonplace.

New LNG importers are steadily growing. China, whose first receiving terminal commenced operation in May 2006, imported 4 bcm of LNG in 2007, compared to less than 1 bcm in 2006; India imported 12 bcm in 2007 at its two receiving terminals, compared to 8 bcm in 2006; and Mexico, where LNG imports started in September 2006, imported about 3.5 bcm in 2007. Argentina, Brazil, the east coast of Canada, and the west coast of North America (Baja California, Mexico) are expected to start receiving LNG for the first time in 2008.

A dockside regasification plant at Teesside, northern England, and a submerged turret buoy regasification plant offshore Massachusetts, United States, were completed in 2007. However, the Teesside facility has only received a partial inaugural cargo in February 2007 and the latter, the Northeast Gateway terminal, had to wait until May 2008 to receive its first commercial cargo after commissioning work was conducted in February. Another dockside regasification plant at Bahía Blanca in Argentina received its first LNG cargo in May 2008, starting operations in the southern hemisphere winter. It is clear

Table 19 Regional breakdown of LNG trades in 2007

		Origin				
		Pacific	Middle East	Atlantic	Total	Share
Destination	Asia	91	52	13	**156**	67%
	Europe	-	7	44	**51**	22%
	Americas	-	1	25	**26**	11%
	Total	**91**	**60**	**82**	**233**	
	Share	39%	26%	35%		

Unit: bcm
Source: IEA provisional estimates.

that the non-OECD market's ability and willingness to import LNG is growing.

A significant number of new countries will enter LNG markets as buyers and sellers in the new few years. Details are set out in Table 20.

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, not withstanding the massive increase in capacity, particularly to 2009. However, long-term prices may not continue rising 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 correspondingly large numbers of ships are delivered, the proportion of short-term cargoes will increase from levels around 10% early in the decade, to current levels of 20%, towards 30% early next decade. Pricing for those cargoes seems likely to be increasingly decoupled from that of long-term transactions and increasingly on a global basis.

Table 20 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)
2000-2007	Dominican Republic (2003), Portugal (2004), United Kingdom (2005), Mexico (2006)		India (2004), China (2006)
2008-	Canada (2008), Argentina (2008), Brazil (2008), Netherlands (2012), Germany (2011), Poland (2011)		Mexico (2008), Kuwait (2009), Chile (2009), Dubai (2010), Thailand (2012), Singapore (2012), Indonesia (2011+)
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)
2000-2007	Egypt (2005), Equatorial Guinea (2007), Norway (2007),		
Future	Angola (2012), Russia (2014), Venezuela (2015+), Brazil (2015+)	Yemen (2009), Iran (2014+)	Sakhalin (2008), Peru (2010), Papua New Guinea (2013+)

*For future importers and exporters, the year in the parenthesis indicates earliest possible start date.
**Hybrid = Producing countries which would be positioned to routinely supply both the Atlantic and Pacific region LNG markets.
Source: IEA.

Evolving value chains and changing business models – portfolio approach and secondary marketing

The rapidly changing world of LNG

The traditional international LNG business started as a point-to-point value chain, with very little flexibility for buyer, seller or volumes. Now both sellers and buyers are working with multiple counterparties. Lifestyles have changed in the business. While projects still need commitments (markets for sellers and supply sources for buyers) to make them happen, different approaches are being used by both newcomers and traditional players.

Portfolio approach (supply) versus aggregator approach (demand)

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. Companies with regasification capacities or sales commitments in multiple consuming regions are also making free on board (FOB) offtake commitments to fill those capacities or to sell (or "divert") to higher paying markets in a more flexible manner than previously seen.

Projects where offtake arrangements are made in such a manner include recent African projects, as well as projects in Trinidad and Tobago and Egypt. In other words, those arrangements are most common in the Atlantic basin, taking advantage of circumstances where arbitrage is possible between consuming markets. Companies with LNG supply portfolios are making sales commitments at LNG receiving terminals in emerging LNG consuming countries, including Chile, Brazil, Hong Kong, China, and Singapore. The potential importers in those emerging consuming countries have been trying to attract LNG supply by inviting those companies with LNG supply portfolios, sometimes as an aggregator of demand and supply.

The strategy of directing output to more favourable markets is pursued in different ways also in the Pacific region. Partners in Australia's Gorgon project 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). 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 are underpinning forecasts of more "spot" or short-term LNG sales.

Diversion of cargoes from one region to another

For the first time, as much as 6% of the Atlantic region's LNG production, 4.8 bcm, was diverted into the Asian market in 2006. This trend was accelerated in 2007 when the Atlantic to Pacific diversion more than doubled to 12.5 bcm. Diversion has also been made within the Atlantic region LNG markets as gas price relativities within different parts of these markets changed dramatically during the year. In addition, some medium-term and long-term agreements which were originally assigned to Atlantic markets on a long-term basis, have been signed to sell LNG into Asian markets.

Growing share of hybrid and long-haul LNG supply

Reflecting higher gas commodity prices and improvements in the economics of transportation by larger LNG carrier ships, the share of hybrid LNG supply sources from the Middle East which can routinely supply both the Pacific and Atlantic region markets is growing. Shipping distances from Qatar to North Asia or North Europe are 11 000 km or longer, while those between Algeria and Mediterranean Europe are around 1 000 km or sometimes less, and those between Southeast Asia and North Asia are mostly less than 5 000 km. The global average shipping distance of LNG in 2007 was 6 700 km, compared to 6 300 km in 2006 and 5 700 km in 2000. It could be 8 000 - 8 500 km in 2010.

Evolution of pricing

While the cost of shipping has historically separated Atlantic and Asia Pacific LNG markets, there are growing interactions between the two, especially because the Middle East is expected to play a bigger role in supplying to both regions. Despite this, the regional gas markets continue to maintain different features and each uses different mechanisms for LNG prices based on the fundamentals of each market. Even within the Atlantic Basin, markets such as the United Kingdom, Spain, Italy and the United States have different gas pricing structures. This appears unlikely to change in the near future. Consequently, neither the markets nor the suppliers appear to be driving the industry towards full commoditisation leading to a single global commodity price, nonetheless, some convergence of pricing may occur.

Japanese average imported LNG prices have been lower per unit of energy than those of crude oil for more than four years; furthermore the gap is widening. Historically, LNG prices were more expensive than oil so many industrial customers had not seen a price incentive to change fuel. Due to 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. In the first half of 2008, LNG was more than USD 5 per MBtu cheaper than crude oil in Japanese markets.

This current trend creates several notable changes both internally and externally: firstly, an accelerated shift to natural gas in industrial energy use; secondly, 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 finally sellers' arguments for price increases, especially in higher oil price ranges. More recently, Indian and Chinese LNG importers have paid expensive spot prices, again rolling prices into cheaper long-term contracts.

S-curve pricing to re-couple to oil prices in Asia

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. The question is to what extent the linkage is made and over what oil price range. In traditional contracts concluded before 2002, the rates of gas price increase and decrease with oil are slowed by half outside a certain oil price range so that buyers and sellers are protected from exceptional oil price environments both at high and low prices. 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 has 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.

Since 2005, after the surge in oil prices, pricing in the unprecedented high oil price range, where even the S-Curve mechanism is no longer applicable, has become the main issue, as LNG pricing at such oil prices was simply not anticipated in traditional pricing formulas. Sellers are generally insisting on steeper slopes to fill the gap. For new long-term contracts, sellers are proposing even higher slopes, as well as less price review clauses.

After seeing higher oil prices in recent years, the S-curve mechanism originally intended to protect parties from sharp fluctuations of oil prices seems less attractive to some sellers, as they tend to regard the mechanism as protection for buyers. Some sellers call this trend the movement towards a simpler pricing formula - simpler for all parties involved. While existing Asian buyers argue that high LNG prices (almost on an oil parity basis) will weaken price competitiveness of LNG, leading to reduced LNG demand, emerging buyers have been encouraged to make commitments at relatively higher prices partly because of higher oil prices forcing them to consider alternative energy sources including LNG.

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 favourable pricing arrangements for those buyers. A similar approach of tendering has been adopted by some sellers, as well as buyers in other emerging LNG markets, including Chile, Mexico, and Singapore.

In 2006, the North West Shelf (NWS) LNG venture in Australia, conducted contract renewal negotiations with some of its long-term buyers in Japan for sales from 2009. Buyers were invited to submit requests for volumes of LNG. The process resulted in increased prices, shorter contract duration and reduced volumes. Arguably the shorter contracts can be seen as favourable 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 seventh train ('SevenPlus' project) between the five selected bidders, reportedly based on a sliding scale with the highest bidding companies getting proportionately more volume. 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.

Earlier marketing activities in the decade targeting the United States' markets by NLNG Plus (Trains 4, 5 and 6) and Yemen LNG had lower percentages of the Henry Hub price when they were negotiated in 2003-04 and 2004-05. An earlier deal negotiated by Equatorial Guinea LNG in 2003 had an even lower percentage.

LNG production: delays and cost increases

As noted previously, the tight engineering and construction market has been blamed for project delays - in both decision making and in execution; as well as cost increases (in estimated costs for planned projects and actual material and construction costs for projects under construction). Environmental concerns are also adding pressures to manage CO_2 and sour components of feedgas streams, as more difficult and complicated gas reserves are set to be developed in the future.

While a major expansion of capacity will occur in the LNG export industry over the next few years, the main question for medium and long-term projections is from where, and how, the next generation of supply will come. Again, and as noted earlier, a final investment decision (FID) for LNG liquefaction project was made in only one case (Peru LNG) in 2006 and three were made in 2007 (the Pluto project in Australia, the Skikda Replacement project in Algeria, and Angola LNG). Hence from mid-2005 to early 2008, only four new projects were sanctioned. On many projects, FID has been delayed, as set out in Table 21.

One major factor in the tight engineering market has been sharp material cost inflation, particularly of steel. The Global steel price index in 2005 was 50% higher than 2003 and cost increases have continued apace into 2007 and 2008. Cement and other raw materials have also been affected. While the current wave of inflation started around the beginning of 2005, it was not until 2006 that the issue was widely recognised by LNG project sponsors.

Another factor is limited human resources - both in terms of the number of capable engineering companies and also of engineers, especially those experienced in project management. Skilled labour forces in subcontracting are also scarce for construction and commissioning during the latter stages of a project.

A small number of companies dominate recently completed LNG plants (grouped according to the proprietary liquefaction process used). These companies are JGC Corporation and Chiyoda Corporation, both of Japan; Kellogg Brown and Root (KBR) and Bechtel of the United States. Other companies include Snamprogetti of Italy; Technip of France; and Foster Wheeler and Chicago Bridge and Iron of the United States.

Despite the frequently discussed shortfall of skilled engineers with project management capabilities, these few engineering companies cannot easily expand their employee bases, as future opportunities are so uncertain. Each of the companies has a few thousand such employees. Thus, there may be a limit to the number of projects (including refineries and petrochemical complexes, as well as LNG) that can be undertaken globally at the same time.

One key project management skill of EPC contractors is procuring skilled labour forces in a timely manner. EPC contractors need to hire subcontractors from countries like Malaysia, Indonesia, Pakistan, the Philippines and Turkey to conduct civil, piping, and tank yard works as materials and components arrive at the construction sites. If the various project construction works take place at the same time, EPC contractors may find difficulties in procuring those labour forces, naturally causing waiting time, delays and extra costs.

Table 21 FID delays (selected LNG projects)

Projects	Notes
Snøhvit, Norway	Production was pushed back several times to 2007.
Peru LNG	Production target was pushed back to 2010, when FID was made in December 2006.
Skikda Replacement, Algeria	FID took three years after the explosion of the original trains as the estimated cost increased rapidly to USD 2.8 billion. Production target is 2011.
Angola LNG	FID was made in December 2007 with more than one year delay.
Nigeria LNG Seven Plus	The original decision target was 2006 when buyers were short-listed to start production in 2010. Production will not come until 2012 at the earliest.
Brass LNG, Nigeria	Shareholders have set a target of end 2008 for FID after passing the earlier third quarter 2007 target.
OK LNG, Nigeria	FID target was 2006 when the project development agreement was signed in February 2006. It has not been made as of March 2008.
Gorgon, Australia	After preliminary sales agreements were in place with Japanese buyers in 2005, the FID target has been postponed from the middle of 2006 to at least 2009.
Gassi Touil, Algeria (former El Andalus)	The original 2009 production target has been postponed. The new FID target was set at 2009 for 2012 production start.
Ichthys, Australia	The FID target has been postponed from the end of 2008 or the beginning of 2009 to the second half of 2009.

Source: media and company reports.

Table 22 LNG liquefaction plants since 1990s; process and EPC contractor

	APCI(1)	POC (5) (most by Bechtel)	Others
1990s	Bontang, Indonesia, 1993/1997, Chiyoda Bontang, Indonesia, 1998, KBR Das, Abu Dhabi, 1994, Chiyoda Qatargas, 1996-98, Chiyoda RasGas, 1999, JGC/KBR Nigeria, 1999, TKSJ (2) Oman LNG, 2000, Chiyoda/FW (3)	Atlantic, Trinidad, 1999	
2000s	NWS 4, Australia, 2004, JGC/KBR Damietta, Egypt, 2005, JGC/KBR/Technip RasGas III 3-5, 2004-2007, Chiyoda Nigeria 3-6, 2002-2007, TKSJ	Trinidad, 2/3/4, 2002/2005 Idku, Egypt, 2005 Darwin, Australia, 2006 Equatorial Guinea, 2007	Snøhvit, 2007, Linde (6)
2008-	Qatar mega trains, 2008-2011, Chiyoda/Technip NWS 5, Australia, 2008, FW Yemen, 2008, Technip, JGC/KBR Peru, 2010, CB&I 94) Pluto, Australia, 2010, FW Skikda, Algeria, 2011, KBR	Tangguh, Indonesia, 2008 (8) Angola LNG, 2012 Brass LNG, Nigeria PNG LNG	Sakhalin II, Russia, 2008, Chiyoda (7)

(1) Air Products and Chemicals Mixed Refrigerant Process.
(2) JGC/KBR, Technip, and Snamprogetti.
(3) Foster Wheeler.
(4) Chicago Bridge and Iron.
(5) Phillips Optimised Cascade Process.
(6) Linde Mixed Fluid Cascade Process.
(7) Shell Double Mixed Refrigerant (DMR) Process.
(8) Only one exception with POC done by JGC/KBR.

Table 23 Factors of the tight EPC market

Limitation of element	Explanation
Limited number of EPC companies	Only a handful of companies can get the job done.
Limited number of engineers with total project management capabilities	Not only technical skills, but also total project management expertise is required. Companies cannot expand engineer base beyond a certain size.
Limited number of subcontractors	Labour forces are needed at the right time.
Environmental concerns	More complicated gas reserves are to be developed (more CO_2, sour and other impurity contents in feedgas stream).
More participants in larger projects	Everybody has to be convinced, meaning more money and time to align shareholder interests.

Capital costs of LNG liquefaction plants, which fell from approximately USD 600 per tonne per year of installed capacity to USD 200 in the 1990s, are now estimated at around USD 1 000 or even more for new plants seeking FID. It should be also noted that USD per tonne figures are highly dependent on site specific factors. Some cited figures include jetty and some utility facility costs, while others do not.

Completion times have also escalated. Plants constructed in 2005 and 2006 were completed in less than 3 years. For example, Darwin LNG in Australia took only 32 months from notice of construction in June 2003 to the first LNG delivery in February 2006. The Qalhat LNG in Oman shipped its first cargo in December 2005 after a construction period of 33 months.

While costs of regasification terminal projects are also rising, the impact of such cost increases is less acute, as a regasification terminal project tends to be a USD 0.5 to 1 billion project, compared to USD multi-billion nature of liquefaction plants. There are innovative ideas to reduce costs in receiving terminals, including onboard regasification applications, or dividing the project into phases (where the project starts with minimum facilities and builds up larger tanks later).

The current escalation of EPC costs is changing the nature of contracting. Traditionally, EPC contracts for LNG plants were awarded on a "lump-sum turn-key" (LSTK) basis, meaning that cost increases after the contract is awarded are borne by the contractor, although there are escalation clauses where certain percentages of cost increases can be absorbed by clients.

However, recent years have seen much higher cost increases, above and beyond originally anticipated levels. There are signs of financial strains among EPC contractors who were awarded LNG plant construction contracts on a LSTK basis, which has caused some to offer higher contracting prices for future projects, as they do not want to assume the risk of uncertain cost increases.

Some contractors have also begun to move from the traditional LSTK to more flexible contracting: "open book estimation" "re-inverse and lead items", or "modular construction." While these changes reduce risks for contractors, they may discourage project promoters from making commitments due to additional risks of cost increases.

Smaller-scale LNG projects

Another possible solution is smaller-scale LNG projects. In addition to base-load liquefaction LNG export plants of 3 - 8 million tonnes (4 - 11 bcm) per year capacity per train, peak-shaving liquefaction facilities of less than 100 thousand ton (0.14 bcm) per year are widely used around the world for domestic gas consumption.

Smaller-scale base-load export plants of 1-2 million tonne (1.36 - 2.72 bcm) per year, which were common in the early days of the LNG business in 1960-1970s, were not constructed in the 1980s and 1990s, as liquefaction technology advanced and train sizes continued to expand to reduce unit investment costs. However, as recently as 2004, a 430-thousand-tonne (0.6 bcm) per-year liquefaction plant was constructed in China for domestic supply.

As capital intensive mega-projects are generally becoming more difficult to develop, smaller base-load projects are worth examining. Such projects tend to have the following merits:

- Smaller feedgas and market requirements;
- Smaller capital expenditure;
- Potentially quicker decision making and implementation.

Although economics of scale would not be as good as for larger projects, meaning that the unit cost of gas may be more expensive, those smaller projects could also open the door for companies, including LNG consumer companies, that are much smaller than traditional LNG developing companies and have not had a chance to participate in LNG liquefaction projects. Due to the smaller scale, those smaller companies could have more control throughout the value chain of the project, providing more strategic LNG procurement. Fewer participants could also facilitate quicker decision making compared to larger scale ones involving more participants. When a project is of a significant size and involves more participants, greater resources, both financial and human, will be required to ensure all participants fully understand the project arrangements.

In addition to the Chinese inland LNG project mentioned earlier, there are several smaller-scale base-load LNG liquefaction export projects emerging. They are described in this section: the two Sulawesi projects in Indonesia; two of the CSM based LNG projects in eastern Australia; and Nordic LNG in Norway.

Some offshore LNG liquefaction projects are also being planned for developing relatively small and stranded gas resources:

- Flex LNG has developed a concept of LNG tanker onboard liquefaction using 90000 m³ class ships that the company has already ordered from Samsung Heavy Industries (SHI) of Korea. Flex LNG is seeking opportunities of 1 - 2 bcm per year projects in Nigeria and Asia.
- In September 2007, plans to develop floating production and storage operations (FPSO) for LNG were announced by two separate groups: a partnership of Dutch company SBM Offshore and German engineering company Linde AG, with LNG hulls to be provided by Japan's Ishikawajima Harima Heavy Industries (IHI); and a consortium of ship owner Höegh LNG, Aker Yards and ABB Lummus Global.

The massive size of the current expansion of LNG capacity is also contributing to the strain in the EPC market. After this current wave of construction nears its end, price pressures may moderate, but for the moment they remain considerable.

The financing business model of LNG projects and finance has developed in each regional market since the 1970s, however, financing models are changing, under the multiple forces of:

- High energy prices;
- Rapid construction inflation;

- The current problems in credit markets making private banks more risk-return conscious than before.

These issues are explored further later in this chapter.

Importing country developments

LNG regasification terminal projects used to be seen as a bottleneck of major gas markets a few years ago. Now they are not and there seems to be a significant number of terminals being built. The current planned regasification capacity is much larger than the planned liquefaction capacity globally. However, there is still uneven progress around the world. It will take a few more years to judge if this apparent weakness of the LNG value chain has been overcome. Delays in investment decision making, as well as construction and commissioning, are also seen in this sector, due to various reasons, which include local opposition to terminal construction, lack of long-term supply sources and scarce spare LNG cargo availability.

Different business models are emerging for LNG receiving terminals. Not only utility, pipeline and wholesale companies, but also purely merchant traders and IOCs, as well as NOCs of gas producing countries are now involved in receiving terminal projects.

New trends of onboard regasification

LNG onboard regasification technology has recently become popular around the world. This is due in part to its quicker implementation schedule when compared to conventional land-based LNG receiving terminals. Successful examples have been demonstrated 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. The company has also installed another offshore buoy and turret system offshore Boston in December 2007, although it had to wait for commercial operation until May 2008. Another dockside regasification terminal opened in Bahía Blanca, Argentina, in May 2008. Kuwait has a plan to open one in

Table 24 Regasification capacity by region (bcm per year)

Region	Operation	Construction	Planned	Proposed	Expected by 2010
Pacific Asia	375	59	53	23	442
Pacific America	10	5	11	26	16
Europe	120	70	98	112	191
Atlantic America	111	94	178	-	197
Global total	**617**	**228**	**340**	**161**	**846**

Source: IEA, company information, media reports. Data as of June 2008.

Table 25 Delays in regasification projects

Project	Delay	Cause
Zeebrugge expansion, Belgium	2007 --> April 2008	Construction delay
Northeast Gateway, Massachusetts, United States	End 2007 --> 2008	The United States Coast Guard (USCG) permission process, Cargo availability
Dragon, Wales, United Kingdom	2007 --> 2008	Construction delay
Fos Cavaou, France	End 2007 --> 2009	Construction delay, piping failure
Sabine Pass, Louisiana, United States	Cool down postponed for a few months, start up April 2008	Construction delay
Costa Azul, Baja California, Mexico	Cool down cargo on hold for two months, start up April 2008	Construction delay
Taichung, Chinese Taipei	January --> August 2008	Pipeline connection delayed by weather

Source: company information, media reports.

2009. They are also expected to be served by Excelerate vessels, although shore connecting facilities are or will be provided by local companies.

There could be at least a few more terminals with onboard regasification technology in coming years. To date, there are three operating LNG regasification vessels (LNGRVs) and seven more of these specially-equipped ships are on order and more are on the way. Excelerate Energy and its shipping partner Exmar dominate orders. Independent LNG ship owner company Golar LNG is adding onboard regasification on four of its vessels to convert them into onboard regasification vessels. Two of them are to be used in Brazil for two planned receiving terminals (one as a floating storage and regasification unit (FSRU) and the other one as a shuttle and regasification vessel (SRV)), and one is to be used as an FSRU in a project offshore Livorno, Italy, where Golar LNG itself has a 16% interest. The remaining one is to be used for a planned receiving terminal in Dubai, the United Arab Emirates, starting in 2010.

Peak demand times, utilisation rates for LNG terminals, seasonal storage issues

LNG terminal usage patterns differ by region, reflecting the structure of LNG demand in various markets. In 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. For example, total annual regasification capacity in Japan, Korea, and Chinese Taipei is more than double annual gas demand. Such redundancy also provides flexibility to meet unforeseen demand increases in

Table 26 LNG terminal regasification/storage capacity utilisation (2007)

	LNG imports/regasification capacity	LNG storage capacity/ (days of imports)
Asia	41%	32
Europe	56%	16
Atlantic America	38%	19
Total	**44%**	**26**

Source: IEA.

particular regions, as those countries do not have pipeline connections from major gas supply sources. In Europe, where large quantities of gas can be held in the system as this includes more underground gas storage facilities, LNG terminals can enjoy higher utilisation rates; the only existing terminal in Italy and the two existing terminals in France enjoy utilisation rates of more than 80%. In the United States, where LNG 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; however the Altamira terminal in Mexico has a relatively higher utilisation rate of more than 55%.

More waste heat utilisation in Europe next to terminals

More combined heat and power (CHP) plants are planned adjacent to LNG receiving terminals in Europe. Waste heat from power plants has been widely utilised in Japan, as well as in the LNG receiving terminals in Puerto Rico and the Dominican Republic. ConocoPhillips plans an 800 MW CHP plant next to its proposed 7.3 bcm per year LNG receiving terminal in Teesside, northeast England. The CHP plant could burn gas from the LNG facility and also provide waste heat to the LNG terminal for regasification. E.ON UK plans to build a 1 275 MW CHP plant at the Isle of Grain. The waste heat would be used to vaporise LNG at the nearby receiving terminal. Dutch utility Eneco plans an 840 MW gas-fired power plant in Rotterdam. The project is a joint venture with British power producer International Power. Waste heat from the plant could be used at the proposed LionGas regasification terminal adjacent to the power plant. Électricité de France plans to utilise waste heat from a nuclear power plant at its planned Dunkerque LNG receiving terminal in northern France.

Further details of receiving terminal developments are in Annex A.

Exporting country developments

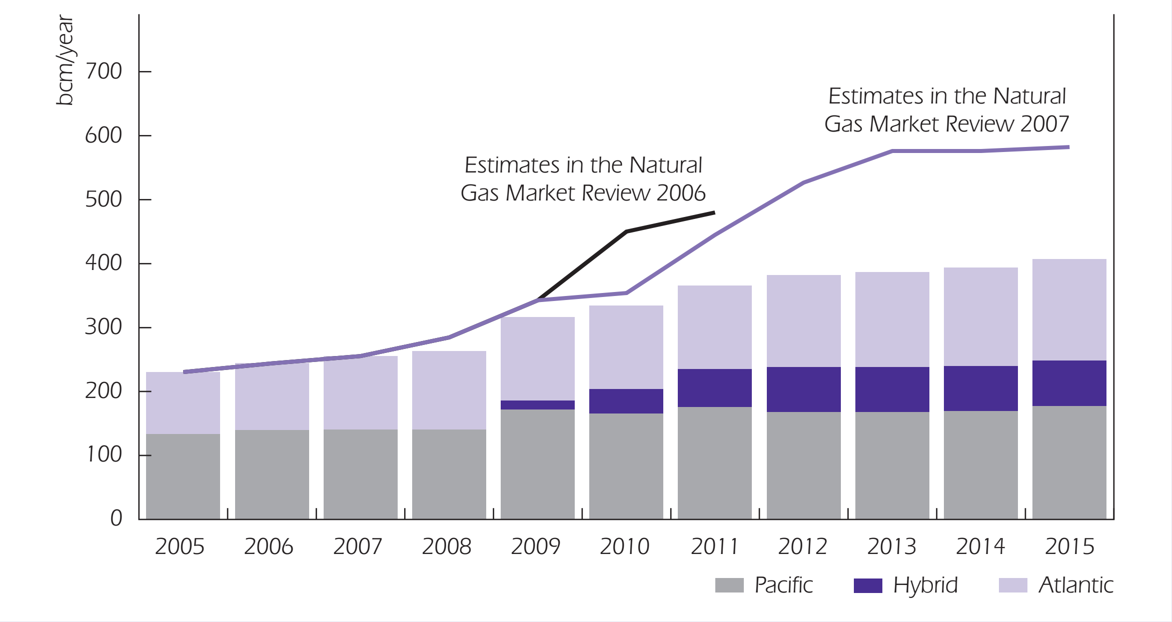
During a period from 2007 to 2011, a significant increase in LNG exporting capacity will occur. This section discusses these projects under construction and, beyond them, future projects under consideration, focusing on factors driving or discouraging them. Up to 2012, the forecasts incorporate projects under construction or for which FIDs have been taken. Beyond 2012 to 2015 new capacity is likely to come from Australia, Nigeria and Russia (Shtokman).

In the chart below, capacity additions until 2012 include projects for which final investment decisions (FIDs) have been taken. Capacity additions beyond 2012 include reasonably achievable projects. FIDs for those projects would be dependent on prevailing market conditions.

Qatar

Qatar is solidifying its position as the world largest LNG exporter. Its exports of 40 bcm in 2007 were 28% larger than those in 2006 and the all-time high for a single country's yearly LNG exports. Its exporting capacity of 41 bcm per year at the end of 2007 will be more than doubled to 105 bcm in the next years, with six "mega" liquefaction trains, 10.6 bcm each, starting production from 2008 to 2011. This is a remarkable achievement, given the industry has only developed in the last decade. Qatar will remain the LNG leader for many years to come. Output from these huge production facilities will be shipped by new mega-sized (Q-flex (210 000 m³) and Q-max (260 000 m³) tankers originally intended for destinations in the Atlantic basin, but initially used to deliver cargoes in Japan and Korea in late 2007.

Figure 17 Expected LNG export capacity by region



Source: company information, IEA analysis.
Note: Hybrid = Capacity which could routinely supply both the Atlantic and Pacific region LNG markets, not necessarily rigidly committed to particular markets at this moment.

While those mega train projects were originally intended for the United Kingdom and United States, some of their output is now to be diverted to buyers in Asia, including Japan, Korea Chinese Taipei, China, India, as well as future importers in Thailand, Singapore and Dubai. By selling some of the most recent volumes in Asia, the Middle East's largest producer is diversifying its markets in terms of geographic spread, and liquid and traditional market combinations. Qatari officials stated in March 2008 that the country envisages a roughly equal distribution of its output among the Asian, European, and North American markets.

Table 27 Qatar's LNG projects and destinations

Trains	Project	Start (previous target)	bcm per year	Basic destinations	Additional destinations	Partners
Qatargas			55.4			
1-3		1997-1998	12.9	Japan, Spain		QP, ExxonMobil, Total, Marubeni, Mitusi
4	Qatargas II	Q3 2008 (Q1)	10.6	United Kingdom	China (CNOOC), Chubu: 1.6 bcm per year 2008-2012	QP, ExxonMobil
5		2009 (2008)	10.6	United Kingdom	Total could send 5 bcm per year to France, North America	QP, ExxonMobil, Total
6	Qatargas III	2010 (2009)	10.6	United States	China (PetroChina), Thailand, Singapore	QP, ConocoPhillips, Mitsui
7	Qatargas IV	2011 (2010)	10.6	United States	China (PetroChina), Dubai, Marubeni, Itochu	QP, Shell
RasGas			49.4			
1-2		1999	9.0	Korea, Spain		QP, ExxonMobil, Kogas, Itochu, LNGJapan
3	RasGas II	2004	6.4	India, Korea, Spain		QP, ExxonMobil
4		2005	6.4	India, Korea	Korea: 2.9 bcm per year starting 2007	QP, ExxonMobil
5		2007	6.4	Spain, Italy, Belgium, Chinese Taipei		QP, ExxonMobil
6	RasGas III	2009 (2008)	10.6	United States	Korea: 3.1 bcm per year starting 2009	QP, ExxonMobil
7		2010 (2009)	10.6	United States	Chinese Taipei, India	QP, ExxonMobil
As of	2007		41.1			
As of	2011		104.8			

Source: company information, media reports.

The mega trains are not immune to the cost increases and delays plaguing the industry as a whole, although slippage to date has been relatively minor. It should be also noted that there is a major study being undertaken on the country's giant North Field on reserve integrity management. The study will not be completed until 2009, meaning that no new major project decision will be taken in the next two years at least. 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 . This de-facto moratorium is discussed further in the Middle East section.

Australia

With declining LNG exports from Indonesia, Australia may be able to secure a greater share of the Pacific LNG market, with several grassroots and expansion projects on the horizon. Though there are hurdles to clear, including environmental agreements, and especially high construction costs, project fundamentals are generally sound.

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

The fifth liquefaction train at the existing North West Shelf project is under construction. The 6 bcm per year unit is on schedule for commissioning in late 2008. Once it is completed, the venture will have a total production capacity of 22.2 bcm per year, out of which the venture will have flexibility volumes of as much as 2.3 bcm per year. Meanwhile, the venture's occasional troubles at the newest Train 4 might cause concerns about future performance of bigger, more recent liquefaction trains (earlier trains were 2.7 - 3.4 bcm per year in capacity).

North West Shelf existing contract renewals

The original sales contracts amounting to 10 bcm per year from the Trains 1 - 3 of the North West Shelf venture with Japanese foundation buyers are expiring in March 2009. Some of the foundation customers have been forced to receive smaller volumes than they currently import from the venture in the renewal deals. Prices look to be higher but are 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.

Bayu-Undan export building up

The second export project in the country at Darwin, Northern Territory, is operated by ConocoPhillips and started exports of LNG to its Japanese customers in 2006. The project is unique in several ways: 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 bcm per year) 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 environmental approvals have been granted for up to 13.6 bcm per year. Potential gas sources for possible expansion could include the Greater Sunrise fields (partly owned by ConocoPhillips and operated by Woodside), the Barossa, Caldita (also partly owned by ConocoPhillips) and Evans Shoal gas fields. Unusually for north-western Australia, the plant is well located close to the existing infrastructure of the city of Darwin.

Pluto – final investment decision, possible expansion

In 2007, a final investment decision (FID) was made on Australia's Pluto LNG project and agreements were concluded between its lead partner Woodside and the project's foundation buyers, Tokyo Gas and Kansai Electric of Japan, for their minor equity acquisition in upstream and liquefaction stages of the projects. The estimated cost now stands at AUD 12 billion, almost doubling the original estimate made in 2005, when the sizable gas reserves were found off western Australia. The partners expect production will start in 2010. This ambitious schedule would amount to one of the fastest LNG exporting projects ever developed. Woodside is retaining 0.6 - 1.3 bcm per year of the project's output for flexible marketing, out of its planned capacity of 6.8 bcm per year. Woodside indicated in February 2008 that it would like to reach a final investment decision (FID) on Train 2 of the Pluto project in 2008.

Gorgon – progress but significant environmental and cost hurdles remain

The Gorgon LNG project partners, Chevron (50%), ExxonMobil and Shell (25% each), are reviewing all aspects of the project. The LNG plant, to be located on Barrow Island off western Australia received federal environmental approval in October 2007. The cost of the project is said to have increased from AUD 11 billion in 2004 to about AUD 20 billion in 2007 for the original concept of two trains with 14 bcm per year capacity. In order to mitigate costs, the partners are planning a front-end engineering study (FEED) study which is expected to be completed in 2009, based on a three-train, 20 bcm per year design. That would delay first production at least until after 2014. Chevron said in March 2008 that Gorgon could eventually become a five-train mega project with a 50 year lifespan. High CO_2 content and environmental issues, as well as engineering and cost issues, are delaying this development.

Marketing efforts made considerable advances in late 2005 by signing up Japanese buyers for Chevron's share of output from the original plan of a two-train plant, assuming 2011 production start. Marketing arrangements for the remaining capacity, assigned to partners ExxonMobil and Shell, have been less clear. Shell signed a binding heads of agreement (HOA) with PetroChina in early 2007 for 1.3 bcm per year of LNG for 20 years, aiming to conclude an LNG sale and purchase agreement (SPA) before December 2008. Before then Shell had 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. Sales have also been discussed with Sempra Energy's 10.3 bcm per year Energia Costa Azul terminal in Mexico, where Shell has 50% of the import capacity. India's Petronet says it hopes to sign an SPA for term imports of ExxonMobil's share of Gorgon output.

Wheatstone: a stand-alone Chevron project?

In March 2008, Chevron announced a plan to develop an LNG project based on its 100% owned Wheatstone gas field off northwest Australia, adjacent to the Pluto gas field. While the company says it has decided that a standalone LNG project is the best option for the reserves after considering a GTL application or possible connection to the Pluto LNG plant at Burrup Peninsula, there is scepticism in the industry whether the company could seriously pursue big two LNG projects in parallel, or whether the standalone approach makes sense at a time when the state and federal governments are encouraging infrastructure sharing among energy projects.

"Major project facilitation status" on Ichthys LNG

The Ichthys LNG proposal, backed by Japan's Inpex Corporation, is based on gas reserves found in its WA 285-P gas block offshore northwest Australia. Inpex has begun talks with potential Japanese buyers for the 8.2 bcm per year of planned output from the project, which was previously scheduled to come online in 2012 but now is likely to start in late 2013 or 2014. Total of France agreed to take a 24% interest in the project and assume a technical advisory role.

Environmental planning is based on a site on the Maret Islands off the Kimberly coast, remote from existing infrastructure. This could be the first development in the Browse Basin. Inpex aims to start construction of the plant at the beginning of 2010, after making a final investment decision in the second half of 2009. Inpex responded to a federal-state initiative of an LNG project siting study in the Browse Basin, primarily targeting the Kimberley coast and effectively ruling out the company's preferred Maret Islands site, by indicating a possibility to pipe gas 850 km from Ichthys to Darwin in the Northern Territory, saying that it had signed a project facilitation agreement with the Northern Territory government.

Browse Basin developments

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 2013 and 2015. Woodside signed a non-binding agreement including key commercial terms with PetroChina for 2.7-4.1 bcm per year of LNG supply for 15-20 years from the Browse Basin gas reserves in September 2007. Woodside also signed key terms of agreement with Chinese Taipei's CPC in February 2008 for 2.7-4.1 bcm per year for 15 years.

Coal seam methane's appeal in eastern Australia

Australia's Santos announced in July 2007 a plan for a 4.1 - 5.4 bcm per year LNG export project at Gladstone in Queensland based on coal seam methane (CSM) from Bowen and Surat Basins, the first of its kind in the world. Santos targets export start up in early 2014. The plan has already been granted significant project status from the Queensland government. Malaysia's Petronas will join the project. In February 2008, BG and Queensland Gas announced a plan to build an LNG export plant of similar capacity at Gladstone, also based on CSM Basin reserves. In addition, Japanese trading house Sojitz and local player Sunshine Gas have planned a smaller 0.7 bcm per year facility in the Gladstone area, and Australian company Liquefied Natural Gas Ltd is targeting a 1.3 - 1.8 bcm per year facility at Gladstone's Fishermans Landing. Shell will join the project. CSM is dry with virtually no liquids.

Alaska

ConocoPhillips and Marathon Oil jointly filed with the United States' Department of Energy for a two-year extension of the export licence of the Kenai LNG facility in Nikiski, Alaska in January 2007. The existing licence expires in March 2009, with the project's sales deal with two Japanese utility buyers. In return for the extended export licence, the two companies agreed in January 2008 to supply gas to south-central Alaska utilities during peak seasons and to aid the development of the Cook Inlet gas reserves by supplying data and drilling new wells in 2008. The 2 bcm per year Kenai plant, the only LNG export facility in North America, was built in 1969 to commercialise gas reserves discovered in south-central Alaska. It was the first long-distance LNG export project in the Pacific and it provided 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 Darussalam

Brunei LNG, a joint venture between the Brunei government, Shell and Mitsubishi, has a five-train plant with a capacity of 9.8 bcm per year. A sixth train, probably with a 5.4 bcm per year capacity, can be planned if more gas reserves are discovered. The Lumut export plant started operations in 1972. Long-term contracts with Japanese and Korean buyers are up for renewal in 2013. The project company is negotiating contract renewals with existing buyers as well as seeking potential new customers.

Malaysia

Malaysia's LNG export in 2007 was more than 30 bcm. This makes Malaysia the second largest LNG export country in the world and the largest among the Asia Pacific LNG exporting countries. Petronas LNG Complex in Bintulu in the state of Sarawak is, with 31 bcm per year, one of the world's largest single concentrations of LNG production capacity. The location was selected because of its proximity to gas resources offshore Bintulu and Tanjung Kidurong port's strategic location. The first project, with 11 bcm per year production capacity, started construction in 1978 and exports to Japan commenced in January 1983.

Further gas discoveries and growing demand for LNG led to a second plant of 11 bcm per year, MLNG 2 (Dua) in 1995. A third plant with 9 bcm per year, MLNG 3 (Tiga), commenced in service in 2003. The MLNG 2 plant capacity is being expanded further to have an additional capacity of 1.8 bcm per year by 2009, bringing the total production capacity to 33 bcm per year.

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 and mid-term sales to India.

The development of LNG projects has been significant for Malaysia, not only because of the successful realisation of a strategic vision to monetise and to add value to the country's gas resources, but also because of the substantial spin-off gains to the country, including the transfer of skills and technology, the development of human resources and other socio-economic benefits.

Indonesia

Bontang contract extension negotiations with Japan

Indonesia's LNG exports were down 7% in 2007. After the country's Ministry of Energy and Mineral Resources released in May 2007 its natural gas balance report, which shows some scope for contract renewals with Japanese customers from the Bontang plant in East Kalimantan in the post 2010 period, Indonesia's state-owned LNG exporter, Pertamina, and the relevant Japanese buyers agreed to renew the contracts for ten years. Annual volume will be reduced to 4.1 bcm in the first five years and to 2.7 bcm for the rest, from the existing 16.3 bcm per year. In the natural gas balance report, a large amount of gas is nominally set aside for potential industrial use, for petrochemicals, and for new gas-fired power generation in the province, which are largely yet to go ahead.

The Tangguh project and its expansion potential

The two-train 10.3 bcm per year BP-led Tangguh LNG project in Papua, Eastern Indonesia, is expected to start up in late 2008, with commercial delivery beginning in early 2009. The venture has a contract with the promoters of China's Fujian terminal for 3.5 bcm per year, starting in 2008. Other long-term sales deals include two Korean sales which have already commenced (currently from other sources, notably Egypt) before actual start of production from the plant; one with Posco for 0.75 bcm per year and another 0.82 bcm per year with K-Power.

A further 5 bcm per year has been sold to Sempra at its Energia Costa Azul terminal in Mexico's Baja California from 2008. Up to half of the Sempra volume can be diverted to other markets, most likely in Asia. Another Japanese buyer, Tohoku Electric, who buys 1.1 bcm per year from Indonesia's Arun through 2009, signed, in May 2008, a purchase agreement for 0.16 bcm per year from the Tangguh venture for a period of 15 years from 2010.

Indonesia is also considering a third 5.2 bcm per year train at the project, which may come on-stream in 2014-15. The project partners plan to conduct further drilling to prove up reserves for the expansion. The partners also say that they might be willing to reserve as much as 2.7 bcm per year for the domestic sector, possibly through an import terminal proposed on the island of Java.

Central Sulawesi small-scale plan

Pertamina, Medco Energi (Indonesia's private upstream player), and Japan's Mitsubishi Corporation finalised a shareholders' agreement in December 2007 for the proposed 2.7 bcm per year Central Sulawesi LNG project, due to come on stream by 2012. Mitsubishi would own 51%, leaving Pertamina with 29% and Medco with 20%. 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 68 bcm of gas. Mitsubishi partly owns Medco. Two Japanese power companies are reportedly interested in buying from the project. The project would be the first in Indonesia to have separate upstream and downstream development. There is still some disagreement between Mitsubishi and the Indonesian partners on feedgas prices, which is delaying the decision making past the target of the first quarter 2008.

Masela Block - FPSO or pipeline to Australia

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 liquefaction plant starting around 2016. Inpex has two options for the reserves; a (floating) liquefaction plant in Indonesia, an idea that Jakarta apparently still favours, or piping the gas to an LNG plant in Darwin, northern Australian, which already hosts another 4.5 bcm per year LNG plant. The Japanese government has offered assistance to this project through financing by Japan Oil, Gas and Metals National and other means.

Natuna D-Alpha restructuring

In February 2008, Pertamina revealed that it would take over the development of the massive Natuna D-Alpha field from the field's former production-sharing contract (PSA) ExxonMobil. The gas could be piped to

Table 28 **Indonesia's LNG projects at a glance**

Area	At a glance	Issues
Bontang	Used to be the largest (30 bcm) in the world. Production declining	Japan contract renewal Exploration progress
Arun	Expected to cease in 2009	A few years extension?
Tangguh	10 bcm LNG expected from 2008 - 2009 to Mexico and Asia	A third train possible - reserves to be proven up in 2008
Central Sulawesi	Small scale LNG export plan (2.7 bcm). Targeting 2012.	Shareholder agreement concluded - Mitsubishi leads
South Sulawesi	Small scale LNG export plan, 4 trains of 0.68 bcm each	Reserves are not proven. Targeting 2009 start
Masela	4 bcm LNG possible	FPSO or piping to Australia? Inpex leads
Natuna D-Alpha	Huge offshore reserve - LNG or pipeline sales to Thailand	PSC revenue allocation, high CO_2 content

Thailand, or Malaysia's Bintulu LNG plant in Sarawak. The block contains an estimated 222 Tcf of gas reserves, but with a high carbon dioxide (CO_2) content of about 70%. About 1 300 bcm of gas is believed to be recoverable, but the separation of CO_2 in these volumes is a big challenge.

Papua New Guinea

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

Papua New Guinea currently has two active LNG export proposals. A proposed gas pipeline under Torres Strait to Australia's eastern states by ExxonMobil and Oil Search was scrapped in early 2007, after a major setback in 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 teamed up with BG to evaluate an LNG exporting project based on reserves not dedicated to the Australian line, but abandoned the plan in October 2007. The Liquid Niugini Gas consortium-grouping Merrill Lynch, Canada's InterOil and Clarion Finanz-plans LNG exports centred on a potentially major discovery in InterOil's Elk field.

On the first of these proposals, ExxonMobil and its partners signed a joint operating agreement in March 2008. This agreement paved the way to start the front-end engineering and design (FEED) work in the second quarter 2008, with first production targeted for late 2013. An agreement was reached on fiscal and technical terms with the government in May 2008. The project would commercialise the Hides, Angore and Juha gas fields, in addition to processing associated gas from the producing oil fields in the Southern Highlands and western provinces. The gas would be transported by pipeline from a gas treatment plant at the Hides field to a planned 8.6 bcm per year liquefaction facility located on the Gulf of Papua. The stakeholders of the project are ExxonMobil (41.6%), Oil Search (34.1%), Australia's Santos (17.7%), Australia's AGL (3.6%), Japan's Nippon Oil (1.8%) and local landowner group MRDC (1.2%). Ownership of the project could change slightly if the government joins as an equity holder.

The Liquid Niugini Gas consortium announced in February 2008 that it had selected Bechtel to conduct FEED work as well as engineering, procurement and construction for its planned 6.8 bcm per year liquefaction plant, which would be modelled on the fourth train of Atlantic LNG which Bechtel built in Trinidad and Tobago. A second train could be built, possibly simultaneously, subject to availability of gas.

Myanmar

Korea's Daewoo International and its partners - Korea Gas Corporation (Kogas) and India's ONGC Videsh and GAIL - considered an LNG exporting project as an option for resources in the Rakhine Basin offshore Myanmar in 2007. However, as Daewoo selected Petrochina as the preferred buyer, the gas would be likely to be transported through a proposed pipeline to China, instead of LNG.

Abu Dhabi, the United Arab Emirates

The Adgas project, a 7.9 bcm per year 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 a long-term basis, with some mid-term sales to Spain.

Oman

Oman, which started exports in 2000 to mainly Korea and Japan on a long-term basis, as well as some mid-term sales to Spain, from a two-train 9.8 bcm per year Oman LNG plant at Qalhat, added another 4.9 bcm per year Qalhat LNG train in early 2006. The plants have been underutilised for some time because of limited availability of gas. Although Oman signed an MoU with Korea Gas to supply up to 2.7 bcm per year by end-2008, there is little chance of increasing LNG production until more domestic supply or imports from its neighbours (Qatar or Iran) are available.

Yemen

The end of 2008 should see the start of exports from Yemen's first 4.6 bcm per year train, followed by a second train of the same size one year later. After first being proposed in the mid-1990s, a final investment decision was made in August 2005. Construction started in October, just before the EPC market crunch began to plague the industry. Estimated costs are said to have increased to USD 4 billion from the previous USD 3.7 billion. This cost overrun is small compared to the more than doubling in budgets experienced recently at other LNG projects in the world.

The project is the first for Total of France as operator and for Technip of France to assume a lead contractor role. This French combination is also seen in Russia's Shtokman project. In addition to Total with 40%, YLNG partners include; state-owned Yemen Gas (17%), Hunt Oil of the United States (17%), South Korea's SK Corp (10%), Kogas (6%), Hyundai Corp (6%), and Yemen's General Authority for Social Security and Pension (GASSP - 5%).

Of the country's 481 bcm proven gas reserves, 255 bcm is earmarked for the LNG project. About two-thirds of the LNG is planned to go to North America and the remainder to South Korea. Yemen's state-owned Safer Exploration and Production Company and YLNG signed an agreement securing gas supply from the Marib basin Block 18 for the LNG venture in January 2008. There had been concerns over gas availability and the sustainability of reservoirs on Block 18 since the control over the block was taken over by Safer from Hunt Oil, one of the partners in YLNG, in November 2005. Total provides Safer assistance in developing the block as a condition for project financing.

A third train is possible, subject to new gas availability and government consent.

Iran

Because of political pressures and concerns over international economic sanctions, as well as estimated cost increases, Iran's proposed LNG projects have not made physical progress. The Iranian oil ministry has given international companies a June 2008 deadline to make decisions whether to invest in their respective LNG projects and upstream development earmarked to those projects: Total and Petronas for the Pars LNG project; and Shell and Repsol for the Persian LNG project. In May 2008, the partners for both projects were negotiating, either to exchange phases of development, or to extend the LNG project deadlines.

Egypt

The Damietta LNG plant, which started LNG production from its first 6.8 bcm per year train in late 2004, receives gas through the state-owned Egyptian Natural Gas Holding (Egas) grid from a mix of gas producers, including BG, BP and Eni. The plant experienced feedgas reductions of 10%-20% in 2007. While it is certain that Egypt's domestic gas demand is rising, it is not certain whether this phenomenon is related to government pressure to further raise gas prices to the LNG plant. The partners want to proceed with a second train of similar capacity to the first. A framework agreement between the operating company Segas partners (Union Fenosa, Eni, Egyptian Gas Holding Co (EGAS), and Egyptian General Petroleum Corp (EGPC)) and BP was signed in March 2005. Production from the second train could start as early as 2012, if an FID is made soon.

Egypt's second export plant, the Egyptian LNG project at Idku, started exporting LNG in early 2005 and currently has two 4.9 bcm per year trains. BG, one of the major partners and buyers in the project, hopes to build a third liquefaction train at the plant. This also depends on the success of exploration efforts and allocation of gas to the domestic market.

Algeria

Algeria, which started exports back in 1964, has an installed production capacity of 27.2 bcm per year from 18 trains at Arzew and Skikda, excluding the three trains at the Skikda plant destroyed in an explosion in January 2004. The plants are operated by state-owned Sonatrach.

In March 2008, Sonatrach agreed with Norway's StatoilHydro to supply 3 bcm per year of LNG to the Norwegian company's capacity at the Cove Point LNG terminal in the United States from 2009. This is in line with the Sonatrach's plan to expand gas sales to the United States.

In July 2007, Sonatrach agreed with Kellogg Brown and Root (KBR) on a USD 2.88 billion engineering, procurement and construction (EPC) contract to build the replacement of the Skikda liquefaction train. The new train is to start operation in November 2011, assuming no further delays. The new train will have 6.1 bcm per year of nameplate capacity, greater than the three trains that were destroyed in the explosion.

The rehabilitation of the plant after the accident has been delayed by cost issues for almost three years. At the current estimate of USD 2.88 billion, the unit cost equates to USD 640 per ton of installed capacity, compared to USD 270 of the recently completed Equatorial Guinea's first train. Skikda's site, which also accommodates existing liquefaction trains, offers some cost savings in relation to marine infrastructure, pipelines and the upstream components, highlighting the price inflation in LNG liquefaction plant.

Algeria's other project, Gassi Touil (El Andalus), backed by Sonatrach and two Spanish partners Repsol and Gas Natural, had already looked unlikely to be on-line before early 2011 at best, (far behind the original target of November 2009), when in September 2007 Sonatrach announced that it had decided to cancel the accord with the Spanish. The engineering contractor KBR offered in early 2007 to build a single 5.4 bcm per year train together with the marine terminal and ancillary units for USD 3.95 billion, equating to nearly USD 1 000 per ton of installed capacity, which was thought to be prohibitively expensive. The project is now targeted for 2012.

Due to these delays in LNG projects, as well as potential delays of pipeline projects, Sonatrach postponed meeting its long touted 2010 export targets of 85 bcm per year (including pipeline gas and LNG exports, compared to 61 bcm in 2006) until 2012, the company said in March 2008.

Libya

The Marsa el Brega LNG plant in Libya is one of the oldest plants (starting in 1970) and is owned by National Oil Corporation (NOC). It used to have a nominal capacity of 3.1 bcm per year, although the country has not exported more than half of that capacity 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.

Italy's Eni, who has been the biggest foreign gas and oil operator in Libya since the years when tough international sanctions were imposed on Libya, signed a wide-ranging agreement with NOC in October 2007. It includes a plan to develop a 5 bcm per year LNG export plant at Mellitah in 10 years, as well as a 3 bcm per year capacity addition to the existing 8 bcm per year Greenstream pipeline to Italy.

Equatorial Guinea

Equatorial Guinea in West Africa exported its first LNG to Lake Charles in the United States from its 4.6 bcm per year export plant in late May 2007. Originally the project was due to start later, in October, so it is early. The gas is very competitively priced at USD 270 per metric tonne of capacity. Partners in the project include Marathon as the operator, state-owned Sociedad Nacional de Gas (Sonagas GE), Mitsui and Marubeni of Japan, for the first 4.6 bcm per year liquefaction plant at its Bioko Island site. There is a slight concern about Marathon's Alba field, which can only support the project for 12.5 years. BG Group has purchased the entire 4.6 bcm per year from the base project over 17 years from start up. The FOB contract allows BG to direct cargoes anywhere in the world. In fact, more than half of its production of 0.9 bcm in 2007 was diverted into the Asian markets, rather than the default destination of the United States.

For a possible second train of 6 bcm per year at the project, a Heads of Agreement was signed between Nigeria and Equatorial Guinea for gas supply from Nigerian National Petroleum Corp. (NNPC) in December 2006. 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 less than 100 km radius from EGLNG. Sonagas signed an agreement to receive pipeline gas from Cameroon's state-owned National Hydrocarbons Corporation in January 2007. However, the possible supply from Nigeria and Cameroon would depend on their own gas master plans under consideration. Marathon was named the leader in the study consortium for the proposed second train by Equatorial Guinea's Ministry of Mines and Energy in February 2008. In addition to the stakeholders of the first train, the team also includes E.ON and Union Fenosa Gas (UFG), who are probably potential buyers of some of the train's output.

Angola

Angola LNG's final investment decision was made in December 2007, (after being postponed several times) and one foreign partner, ExxonMobil, was replaced by Italy's Eni. The project is now owned by Chevron (36%), state-owned Sonangol 23%, Total, BP and Eni 14% each. The project plans to start production at its proposed 7.1 bcm per year plant in early 2012. The venture's preferred outlet is the Clean Energy terminal planned by Gulf LNG in Pascagoula, Mississippi, in which Sonangol has a 20% interest along with El Paso Corporation (50%) and Crest Group (30%). The terminal is due to open in late 2011, just before the liquefaction venture. At present attention is focused on securing additional gas supplies for a possible second train.

Nigeria

With the addition of Train 6 in December 2007, Nigeria's LNG liquefaction capacity of 30 bcm per year is the largest in the Atlantic basin. The train is expected to start commercial delivery in mid-2008. A final investment decision on the seventh and eighth trains, 10.9 bcm per year each, at Nigeria LNG (NLNGSevenPlus) has been postponed. Startup will be likely to be delayed by at least one year to 2012 or later. Brass LNG is also targeting production start up in 2012 or later. Total replaced Chevron in the project in 2006, and it plans to have capacity of 13.6 bcm per year from two trains. BG, BP, and Suez have each agreed to buy 2.7 bcm per year each from the project. The ownership of the project is NNPC (49%), ConocoPhillips (17%), Eni (17%) and Total (17%). The Partners hope to make a final investment decision by the end of 2008.

Olokola LNG (OKLNG), which groups NNPC (49%), BG (13%), Chevron (19%), and Shell (19%), plans a two-train, 15 bcm per year plant, which could be expanded to four-train, 30 bcm per year at a later date. The likely start up date for the production is 2013 or later.

Although production at Nigeria's existing LNG plant in Bonny Island has not been affected by ongoing violence in that country, there is understandable concern about security issues among LNG developers.

Russia

Sakhalin II received its first pre-commissioning cargo in early July 2007 from Indonesia's Bontang plant. A second pre-commissioning cargo arrived from Alaska's Kenai plant in early October 2007. The two cargoes were to expedite the venture's commissioning schedule by several months because its original feedgas is only expected to come several months later via a pipeline that has not been connected from the gas field.

The Sakhalin II project has estimated gas reserves of 500 bcm. Japanese customers have an advantage in transport costs by being relatively close to the exporting project.

Although the Sakhalin I and II ventures were "grandfathered" in Gazprom's monopoly over gas export that Russia's legislature 'Duma' confirmed in July 2006, Shell and its existing partners in the Sakhalin II venture, 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, faced with growing pressure from the state's environmental agency. 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 were seen by many Russians as unfairly advantageous to foreign shareholders.

After the share transfer agreement, Gazprom confirmed that all 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 Sakhalin I gas, although the project operator ExxonMobil says it has agreed to sell the gas to China via pipeline. Russia insists domestic supply is the priority for the Sakhalin I gas.

Table 29 Sakhalin I and II projects in the Pacific

Stakeholders	Marketing	Remarks
Sakhalin I - ExxonMobil, Sodeco (Japan), ONGC (India), Rosneft, Sakhalinmorneftegas	8 bcm per year piped gas or LNG Piped gas to China or Russia's domestic market; LNG call is made from India and Japan	ExxonMobil has planned to pipe gas to Northeast China, but Russia claims domestic supply is priority
Sakhalin II - Gazprom, Shell, Mitsui, Mitsubishi	13.1 bcm per year of LNG Planned volumes have been sold out on long-term basis to Asia and West Coast North America	50% + 1 share transferred to Gazprom LNG deliveries to start late 2008 or early 2009

Source: Company information.

Cargo trading activities

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

Shtokman LNG project

The Baltic LNG project, which was supposed to have a capacity of 7.2 bcm per year at a site near St. Petersburg by around 2010, could have been the company's own first LNG export venture in the Atlantic Basin. Gazprom invited Algeria's Sonatrach to participate in the project in January 2007 but discussions have ceased. Canada's PetroCanada, Italy's Eni, Japan's Mitsubishi and Britain's BP were reportedly short-listed as potential partners. In February 2008, Gazprom decided to abandon the project to concentrate on the giant Shtokman development in the Barents Sea.

Gazprom announced in October 2006 that it would proceed with the Shtokman project on its own rather than sharing the project. Subsequently in 2007, Gazprom selected Total of France and StatoilHydro of Norway as partners in the first phase development of Shtokman. Total and StatoilHydro have 25% and 24% stakes in the Shtokman Development company formed in February 2008 to operate the venture, while Gazprom will own and market all the hydrocarbons through its affiliate Sevmorneftegaz. Shtokman Development would be responsible for project engineering, construction, financing and operation during the first stage of 25 years. The first target is gas delivery to Europe through the planned Nord Stream pipeline in 2013 and LNG exports with one 10.2 bcm per year train are planned to begin in 2014, when Shtokman production would reach 23.7 bcm per year. A second phase has been proposed and could include another liquefaction train, and a third phase could include two more trains.

Table 30 Gazprom's Shtokman project phases

Phase, year(1)	Partners	Production, distribution (bcm per year)	Remarks
I 2013-14	Total 25%; StatoilHydro 24%(2)	1.2 domestic, 12.2 Nord Stream (2013-), 10.4 LNG (2014-)(3)	March 2008 FEED FID target: 2009
II 2018	Go alone	10.4 LNG(3), the rest pipeline	
III 2022	Go alone	Entirely LNG(4)	
IV 2026	Go alone	To be decided	Subject to additional gas discovery

(1) Each phase is expected to produce 23.7 bcm per year.
(2) Participation by Total and StatoilHydro is limited to building, operating and owning infrastructure.
(3) One LNG train each for the first and second phases.
(4) Two LNG trains for the third phase.

In March 2008, Shtokman Development selected France's Technip, Doris and United Kingdom's JP Kenny as contractors for FEED works for the first phase of the project.

There are expected to be significant technological and engineering challenges for developing the field and connecting pipelines, which will have to cross 600 km to the onshore treatment facilities at Teriberka in the Murmansk region over uneven seabed under icebergs and drift ice. Given the technical issues involved, the timeframe for initial delivery seems ambitious.

Norway

Norway's Snøhvit project started production in 2007 at the Hammerfest LNG plant in northern part of the country. The plant became the first LNG exporting facility in Europe and the Arctic region. Contractual deliveries were scheduled to begin in December. However, a leak at the project prevented the equity partners from benefiting from strong gas markets in Europe in late 2007. Two early cargoes left in November 2007 before the plant stopped LNG production for two months. After resuming delivery in February 2008, the plant is expected to be operated at 60% of the nameplate capacity for the rest of the year.

This project is very novel, has faced many technical challenges and has encountered considerable delays. The project expects to separate and inject CO_2 into the Tubaen reservoir beneath the gas-producing layers. As 5%-8% of Snohvit gas is CO_2, the project expects to sequester 700 000 tons per year of this CO_2 from the gas stream once regular LNG production starts.

In July 2007, Norwegian utility Lyse Gass and gas carrier operator Skaugen established a joint venture Nordic LNG, to provide a small-scale LNG supply chain for Scandinavian and Northern European gas markets. The annual production capacity will be 0.4 bcm in 2010 at Risavika, north of Stavanger. The LNG will be delivered to customers by a small 10 000 m^3 LNG carrier under construction in China.

Trinidad and Tobago

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' LNG markets in 2007 was 59%, compared to 67% in 2006. 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. 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, subject to meeting domestic needs for gas based industry.

Venezuela

After talk of exporting LNG for more than 15 years, Venezuela has seen little 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 a source for an LNG project. State-owned PDVSA signed a joint venture agreement with Argentina's Enarsa to build the Gran Mariscal LNG plant in Guiria in May 2008. There is also a possibility that the gas could be processed at Trinidad's nearby Point Fortin plant, if talks between the two countries advance in that direction.

Peru

The Peru LNG consortium, comprising Hunt Oil of the United States (50%), SK of Korea (30%) and Repsol YPF (20%) of Spain, is building a liquefaction plant on Peru's southern coast, which will produce 6 bcm per year of LNG. Feedgas will come from the Camisea fields in the southeast 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, expected to be completed in first half of 2010, will be the first in Pacific South America. The majority of the output from the plant is contracted to Mexico's planned Manzanillo terminal on the Pacific Coast. Some volumes may be sold to Asian LNG buyers.

Changing trends in LNG projects and finance

The following section evaluates the impact of the ongoing economic problems first observed in August 2007 (particularly the difficulties in credit markets) for financing of large scale LNG projects. It does this against the background of evolving financing structures and methods in the LNG industry in the last two decades, as well as recent trends in the industry, notably the marked inflation in project costs, and changing gas prices.

Historical context

The 1970s to the early 1990s

Japan has been the largest importer of LNG since the 1970s. Gas producing countries, national oil companies (NOCs), international oil companies (IOCs) and Japan established the business model for this "value chain industry". Substantial amounts of investment were devoted to the development of upstream, liquefaction facilities, related infrastructure, vessels and regasification facilities through the 1970s and the 1980s. Brunei realised the first LNG project in Asia, followed by Indonesia and Malaysia. In Oceania, Australia achieved a great success with the North West Shelf (NWS) project while Abu Dhabi became the first LNG producer in the Middle East. Korea and Chinese Taipei joined this business community as importers, and the LNG market in the Asia-Pacific region began to expand.

From the viewpoints of investment and finance, the specifics of this "Asia-Pacific LNG Business Model" constituted a "straight-line chain", which tied up specific sellers and the buyers of each project to mutual long-term commitments. The key elements of this business model were as follows:

- Early off-take commitment by buyers covering full or significant volumes produced from the project;
- Long-term off-take contracts with "take or pay clauses" (usually 20-25 years);
- Stable sales price mechanisms incorporated into the off-take contract (with a pricing formula linked to oil prices via an "S curve");
- Total investment planning for all segments of the value chain from upstream to regasification facilities;
- Total financial planning for each of the above-mentioned investments.

Multi-billion dollar investments were required to realise each project, and around three quarters of investment costs were provided by lenders as limited recourse finance on a long-term basis (usually 12-15 years). Limited recourse finance (usually referred to as "Project Finance") is the finance for which repayment primarily relies on the cash flow generated by the project with the project's assets, rights, and interests held as collateral and partial recourse to the borrowers or sponsors for some limited risks. Consequently, the three elements were essential for lenders in order to secure the future cash flow for repayment. Japanese governmental finance institutions played a significant role in enhancing private investment and finance for each segment of the value chain. With enormous efforts by related parties, the finance structure for LNG projects was established in the Asia-Pacific region. Appropriate risk sharing was negotiated and tied up in the "security package". Lenders accepted several post-completion risks, mitigating risks by the assignment of the long-term off-take contract. Sponsors could accept the risk of the plant completion by hedging the risk through signing the engineering, procurement and construction (EPC) contract with reliable engineering companies on a "lump-sum turnkey (LSTK)" basis.

Qatargas, the first LNG project in Qatar, initiated in the late 1980's, showed one of the best practices of this "Asia-Pacific LNG Business Model". Sponsors consisted of Qatar Petroleum (QP, the NOC of Qatar), IOCs and Japanese companies. Japanese utility companies made commitments for the long-term off-take of all products emanating from the project. JEXIM (currently JBIC) not only led syndicated loans for the debt portion of the liquefaction plant, but also extended sovereign loans to the Qatari government in order to finance QP's equity portion of the project and the related infrastructure development since the Qatari government had difficulties obtaining funding at that time.

The middle of the 1990s to the 2000s

The first change to this "Asia-Pacific LNG Business Model" has been observed since the middle of the 1990s. The European gas market, where pipeline gas supply had been dominant, was seeking diversification of supply sources. The North American LNG market was also anticipated to expand due to an increasing number of gas-fired power plants and declining domestic pipeline gas supply. In Asia, India and China started planning the import of LNG. Based on this anticipated rapid expansion of LNG demand in each region, many supply projects were planned and hence potentially competing with one another. However, Japanese users were reluctant to make early commitments for additional volumes while facing uncertainty of future domestic demand caused by regulatory restructuring and sharply reduced economic growth. Given these circumstances, the LNG business model was diversified.

Initially, the European LNG business model was similar to the Asia-Pacific model. European gas users committed to long-term off-take contracts with take or pay clauses and oil-linked price formulae, which traditionally prevailed in the pipeline gas business. However, from a financing viewpoint, country risk was one of the key issues to develop LNG supply projects, particularly in African countries. Incremental Algerian LNG projects had been carried out by state-owned Sonatrach, the NOC of Algeria, since the 1980s. The Algerian government provided funds for Sonatrach; sometimes using sovereign loans supported by ECAs (Export Credit Agencies) for the procurement of project equipment, but did not use project finance. In the early stages of the Nigerian LNG project, Shell, as the leading foreign partner of Nigerian National Petroleum Corporation (NNPC, the NOC of Nigeria), had to provide almost all the finance required. After the start of operations of Train 3 in early 2000s, several ECAs, including the ECGD (United Kingdom), SACE (Italy), US EXIM (United States) and NCM (Netherlands), and international private banks, started financing plant expansion in Nigeria. The African Development Bank (AfDB), the multilateral financial institution, supported the project as well. For Egyptian LNG, the European Investment Bank (EIB) supported syndicated loans in 2004 and 2005 by means of "Article 18", which is the guarantee facility designed to enhance cooperation between Europe and Mediterranean countries.

IOCs, including traditional ones and newly emerging international gas companies, were very confident about the future LNG market in the early 2000s. The United States' market seemed to be particularly attractive because demand was increasing and sales prices, which were largely determined on the basis of Henry Hub prices, were anticipated to be higher than those of other markets, even though they were likely to be volatile. Since 1999, the partners of the Atlantic LNG project in Trinidad and Tobago have been displaying a new business model, which is designed to deliver LNG to either European or the United States' markets to seek arbitrage opportunities caused by price differentials between these markets. In order to achieve such a flexible trade, sellers had to have a free hand in delivering LNG without long-term sales commitments to particular end-users and, at the same time, retain their own marketing networks capable of transportation and regasification for multiple destinations. This means that sellers have had to take all market risks not only as sponsors of export projects but also as off-takers of products. BG, BP and Repsol YPF, international partners in Atlantic LNG, were willing to take these market risks, and financed the projects by themselves. Oman has developed a hybrid model, which was partially based on the conventional Asia-Pacific model, whereby some share of product was off-taken by IOCs and Japanese trading companies for sale to multiple destinations.

Under these circumstances, "brownfield projects" took advantage of their competitiveness on both capital and operating costs. Indonesia, Malaysia and Australia increased their production capacity by de-bottlenecking and the expansion of trains in existing plants. At that time, major Asian users were still reluctant to commit themselves to additional long-term off-take, but they recognised the need to prepare for seasonal demand fluctuation, back-up supply for emergencies, such as possible electricity supply problems and possible demand increases in the near future. The cost competitive surplus of supply had corresponded to their needs and various types of transactions and contracts such as spot trades, swap trades, short or medium term contracts and option contracts were realised.

In this changing market, it was observed that several Asian users began to cooperate to procure LNG efficiently. For example, Korean Gas Corporation (Kogas) and several Japanese utility companies signed the "time swap agreement", which means the swap of LNG cargoes exploiting the differing peak demand seasons in each country. Swaps became more common, but "destination clauses" restricted flexibility.

From the onset, lenders were surprised at the new trend from the "straight-line chain" model to the multiple-destination or "flexible network" model. Lenders recognised they could mitigate the volume risk if IOCs accepted commitments to long-term off-take. However, how could the future price risk be estimated? The lenders' task became far harder requiring analysis of demand/supply projections and future prices in each region. Thus, they attempted to develop new financial structures in response to such a flexible business model. In the case of the Malaysia Tiga project, for example, flexibility for the repayment schedule was incorporated into the loan contract corresponding to the changeable future cash flow based on several transactions.

Assuming a rapid increase in demand in the Atlantic region and a steady increase in demand with some uncertainty in the Asia Pacific, Middle Eastern producers, Qatar in particular, were beginning to assume an advantageous position as "swing producers", capable of delivering LNG to both regions. Thus, Qatar planned production capacity expansions and sought to diversify their funding to obtain more attractive finance. RasGas was the first LNG project to be financed by project bonds issued in 1996, which amounted to USD 12 billion, with a 25-year tenor and a BBB rating by Standard & Poor's (S&P). Notwithstanding events such as the Asian financial crisis in 1997, Qatar succeeded in issuing serial bonds in 2006 and 2007 for the RasGas II and III projects collectively for a total amount of USD 22.5 billion, with 15-22 year tenors and an A rating by S&P. On the other hand, the Qatargas II and III projects used conventional project finance supported by ECAs with the most favourable financial margins. The reasons for the successful financing of Qatar projects can be summarised as follows:

- The competitive feedgas price;
- The competitive capital cost as a result of the scaled-up plants and vessels;

- The advantage of brownfield projects;
- The creditworthiness of sponsors and strong support from IOCs;
- The strong appetites of lenders and bondholders backed by high liquidity in global money markets.

Changing trends since 2004

The LNG business requires long lead times and negotiations. Investors need to have more than five years' foresight in order to be able to decide upon the investment. In the past five years up to 2008, one of the most unexpected events for the LNG business may be the dramatic change of oil prices, which has had a significant impact on the LNG market. Uncertainty for investors is expanding in numerous ways and is causing delays in making final investment decisions (FIDs) for new supply projects.

Changing gas prices

High oil prices have affected each regional LNG market in different ways because gas prices in the United States are determined on a "gas-on-gas" basis while Asian and European gas prices are primarily determined by oil-linked price formulae, albeit rather different in operation. Even in the United States' market, gas prices have increased but remain well below oil parity. In the Asia-Pacific market, the LNG prices of existing off-take contracts are cheaper than oil prices on an energy basis, thanks to the S curve price formulae. However, since spot LNG demand has been increasing for the last few years due to reasons such as cold winters and nuclear outages in Japan, Asian LNG buyers have paid high prices for spot cargoes. As noted earlier, many cargoes came from the Middle East and Africa, which were originally planned for delivery to the Atlantic market. Japanese users are facing renewal periods of existing off-take contracts. It is likely that the price formulae will be renegotiated and that resulting prices will be higher. In this current price environment, predicting future LNG price movements and flows is becoming increasingly difficult.

EPC cost escalation

Again as noted earlier, material costs have been increasing worldwide and engineering capacity is tight as well as skilled labour.

Table C-1 in annex C shows the "unit cost" (USD per tonne; capital investment amount installed annual production capacity) of current LNG projects, assuming for simplicity the amount of finance as the total amount of capital investment. Each project has its own specificities such as technology, location and also whether the project is a greenfield or a brownfield one. However, it is obvious that the capital cost of LNG projects declined until 2005, when it started to increase rapidly.

The unit cost of LNG projects amounted to about USD 600 per tonne in the 1980s, which subsequently decreased during 1990-2000, particularly in brownfield projects, such as Malaysia Tiga, of which the unit cost is estimated at USD 275 per tonne.

Projects undertaken in the early 2000s were realised at low costs. Egyptian LNG and SEGAS in Egypt amounted to USD 240-367 per tonne while Oman's

Qalhat achieved costs of USD 200 per tonne. In Qatar, the cost initially decreased as a result of scaled-up plants, but has recently increased. The average unit cost of RasGas II and III was estimated to be USD 347 per tonne whereas Qatargas IV is USD 732 per tonne.

The unit cost of recent projects such as Angola and Australian Pluto is reported to be USD 700 - 800 while Sakhalin II in Russia is estimated to be over USD 1 000 per tonne. This means that USD 3–4 per MBtu needs to be paid just to cover the capital costs for liquefaction, which were previously USD 1-1.3 per MBtu. Of course, costs of feedgas, operation and shipping must be added for delivered cost. Thus, the period of LNG prices around USD 5-6 per MBtu may be over. It was therefore understandable that investors were and remain hesitant in making FIDs for new LNG projects because such high cost projects would not be feasible under the gas prices based on existing formulae in Asia, as well as the Henry Hub, prevailing in 2006 and well into 2007.

The sharp escalation in cost also affects the type of EPC contract. These changes in contract type also seem to be having a negative effect on FID because sponsors have to take additional risks relating to the construction of costs under such contracts.

Changing gas producing countries

A noted earlier, the frontier of LNG supply projects is also broadening. Table C-2 shows the *Country Risk Classification* from the *Arrangement on Export Credits* by the OECD. New projects are planned and proposed in emerging countries, such as Equatorial Guinea, Yemen, Peru, Angola, Papua New Guinea (PNG), Libya and Iran. New project sites are not easy for investors and lenders to access due to physical, technical or political reasons. The changing relations between foreign investors and host countries are another trend. In Russia, Gazprom took over the controlling share in the Sakhalin II project in 2007. In Yemen, the National Assembly refused an extension of Hunt Oil's concession of the gas field that is marked to supply to the LNG plant under construction, and the NOC of Yemen took over the concession. Such incidents cause delays in project implementation. One of the key issues is the question as to who will take the political risk on the debt portion of project finance. However, a more serious issue is the question who can provide finance for the government or NOC with regard to their equity portion of the project as well as infrastructure development if it is necessary.

The increase in domestic demand in producing countries throws up a complex problem for LNG projects. In the case of Indonesia, the government has changed the priority of gas usage from export to domestic consumption, and announced reductions in LNG export volumes at expiry and/or renewal of LNG sales contracts. One of the reasons for the policy change is that domestic gas is required as an alternative to oil imports. More generally, domestic gas demand is increasing in many producing countries. Gas is increasingly required for generating power and water, fuels and feedstocks of petrochemicals, as well as for reinjection to oil fields.

Changing financial markets

Before the current economic problems first became clear in August 2007, the international financial markets had abundant liquidity. Even in the project finance market, lenders' strong appetites had resulted in severe competition and thin margins. In particular, in the Middle East and North Africa (MENA) region, oil revenue surpluses were driving industrial diversification. Consequently, many projects were launched and international banks, as well as Islamic banks, competed strongly to finance LNG projects. Under these circumstances, Egyptian SEGAS and Qatargas IV projects achieved financial close in mid-2007 with quite favourable margins of 60-90 bp[12] and 50 - 60 bp even for the post-completion period.

As far as the project finance market is concerned, the problems in credit markets over the period from August 2007 had the following outcomes:

- Banks' funding costs have increased around 20-25 bp (30-35 bp for some banks);
- Internal tension within banks has increased for risk analysis and the pricing of margins;
- Thus, the lending price (margin) is increasing and terms are tighter.

However, banks' appetites for LNG project finance are still positive because the asset of LNG project finance is categorised as being more sound and profitable compared to other assets such as acquisition finance. Up to mid-2008, a serious lack of underwriting does not seem to have been apparent, but higher pricing and good structures are required because banks are becoming more careful in assessing risks. In fact, over the period from August 2007, the "market flexibility clause"[13] has been activated, which was previously rare. It was often observed that prices were reviewed to increase up to the cap on this clause, which is usually 15 - 20 bp. Yemen LNG is the first LNG project which achieved financial closure on project finance terms in the current difficult financial environment. It was successful because of a well-structured project with strong support from Total as a sponsor and from ECAs, COFACE of France, KEXIM of Korea and JBIC and NEXI of Japan. But if the finance had been closed more quickly, sponsors would have benefited from lower interest rates. Most recently, finance arrangements are close to completion for Peru LNG project, which is strongly supported by multilateral financial institutions (Inter-American Development Bank and International Finance Corporation).

At present, many LNG projects are planned for emerging countries at a time when EPC costs are sharply increasing globally. In terms of financial resources, due both to decreased liquidity and the growing risk awareness of commercial banks following the subprime loan crisis, the role of ECAs and multilateral financial institutions is likely to become much more important in the future.

12. The basis point: a unit that is equal to 1/100th of 1% and is commonly used for calculating changes in interest rates, equity indexes and the yield of a fixed-income security.
13. This clause is incorporated into syndicated loan agreements, which defines that if banks are unable to sell exposure at syndication, they can increase margins and fees, and in some cases, structures may be adjusted.

OECD COUNTRIES AND REGIONS

Japan

Natural gas currently makes up almost 15% of Japan's total primary energy supply. Domestic production is low providing approximately 3.71 bcm, or only 4%, of gas consumption. The remainder, 91 bcm, is imported in the form of LNG as the country has no pipeline links with neighbouring markets.

The 93.5 bcm (67 million tonnes) Japan imported in 2007 represented an increase of 8.5% from 86 bcm (62 million tonnes) in 2006. This strong growth continued into the first half of 2008. The bulk of LNG imports are sourced from eight countries (Indonesia, Australia, Malaysia, Qatar, Brunei, the United Arab Emirates, Oman and the United States) under long-term contracts. About seventy per cent was sourced from just Indonesia, Australia, Malaysia and Qatar in 2007. Atlantic region suppliers (Egypt, Algeria, Nigeria, Equatorial Guinea, and Trinidad), provided nearly 5% of Japan's total consumption in 2007, compared to 2% in 2006. Russia is expected to be added as the ninth supplier in the near future, with Sakhalin. Spot supplies, notably from the Atlantic Basin, were a small but important component of meeting the relatively sharp demand increase in 2007.

The average LNG landed price was USD 7.71 per MBtu in 2007, compared to USD 7.10 per Mbtu in 2006. The average LNG price in 2007 was 64% of the average crude landed price (JCC). The LNG/crude price ratio was the same as that of 2006 although of course the absolute differential widened to more than USD 4 per Mbtu. The gap between crude and LNG prices is expected to be narrower in the future as higher long-term contract prices

Table 31 Japanese natural gas consumption

Unit: Million cubic metres	1970	1980	1990	2000	2003	2004	2005	2006	Change 1990-2006	Change 2000-2006
Electricity	1 381	18 170	39 537	56 060	58 120	55 870	52 844	58 086	47%	4%
Share	35%	71%	68%	67%	65%	63%	60%	60%		
Commercial and public services sectors	215	885	4 601	10 453	12 363	13 974	14 642	17 006	270%	63%
Share	5%	3%	8%	12%	14%	16%	17%	18%		
Residential sector	555	3 409	8 699	10 681	10 904	10 629	11 096	10 942	26%	2%
Share	14%	13%	15%	13%	12%	12%	13%	11%		
Industrial processes	1 735	2 491	4 729	6 299	6 796	7 310	8 293	9 121	93%	45%
Share	44%	10%	8%	8%	8%	8%	9%	9%		
Other	47	604	558	333	833	1 032	1 324	1 473	164%	342%
Share	1%	2%	1%	0%	1%	1%	2%	2%		
Total consumption	**3 933**	**25 559**	**58 124**	**83 826**	**89 016**	**88 815**	**88 199**	**96 628**	**66%**	**15%**

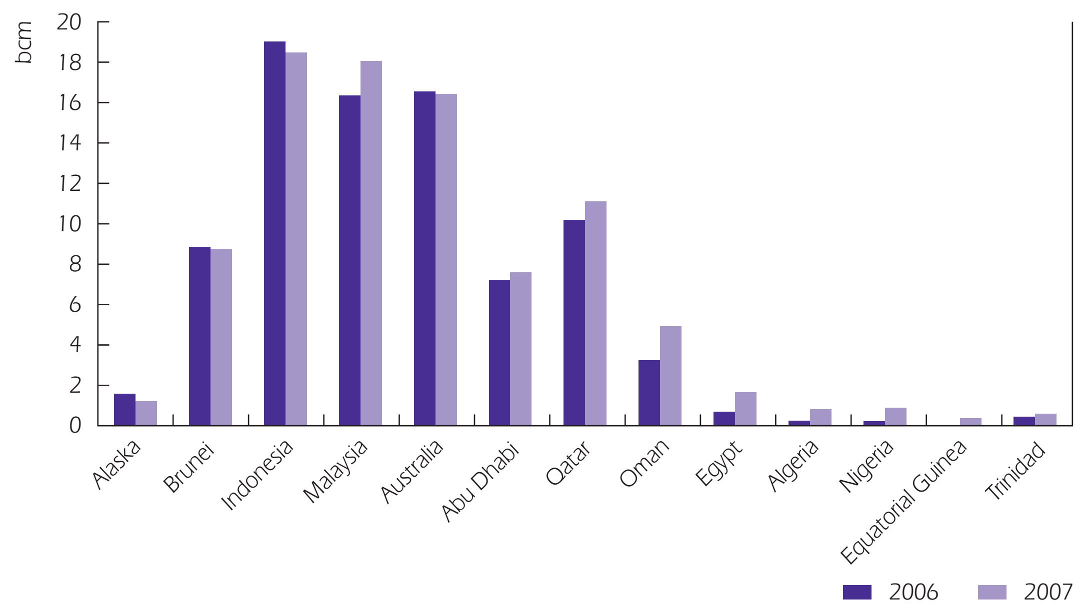
Source: Natural Gas Information, IEA/OECD Paris, 2007.

are negotiated. Japan paid USD 27 billion for its total LNG imports in 2007, compared to USD 23 billion in 2006.

Total consumption of gas was almost 94.58 bcm in 2007, representing a 7% increase from 2006 (87.88 bcm). In 2007, 61% of LNG consumption was for electricity generation, a share of total gas demand that has been declining since its peak in the 1980s as the commercial and industrial sectors have found gas more appealing due to its price advantage over oil. Natural gas provides about one-fifth of Japan's power production. In 2007, the share of thermal power generation increased to 51% of the total generation from 47% in 2006 because of reduced operations of nuclear[14] and hydro power plants. These factors combined with strong growth of power demand due to reduced availability of nuclear and hydro led Japanese electric utilities to increase their LNG consumption 13% year-on-year to 56 bcm in 2007. Japanese LNG imports look set to increase by around 35% to 2030, much faster than any other major fossil energy source, chiefly on the back of a more than 50% increase in gas-fired power over the same timeframe. Any faltering in ambitious nuclear plans (growth of 42% to 2030 planned) will put further pressure on fossil-fired electricity.

Less than 20% of natural gas is used in the commercial and public services sector and 11% in the residential sector. While

Figure 18 **Japan LNG imports 2007, in comparison with 2006 (by source)**



Source: IEA.

14. Japan currently has 55 nuclear units (totaling 49.6 GW of capacity). In addition two reactors are under construction. As of March 2008, 26 units of the total 55 units are operating normally while the remaining 29 units are under maintenance shutdowns.

residential gas consumption remains modest, consumption has continued to grow. About 26 million households have natural gas connections.

Structure of the gas industry

As noted above the majority of natural gas is imported by Japan's electricity companies for power generation. These utilities, and some large industrial users, import their gas independently from the city gas industry. Electric utilities also supply LNG to other new entrants to the gas market. At the same time gas companies have also edged their way into the electricity market.

Vertically integrated regional companies form the basis of the city gas industry and by the end of March 2007 there were 213 general gas utilities in Japan, of which 33 were public utilities. However, three major utilities Tokyo Gas, Osaka Gas, and Toho Gas share around three-quarters of the market. In 2007, Tokyo Gas had a market share of 36%, Osaka Gas 27% and Toho Gas 11%. In addition to the general gas utilities, there are also over 1 600 small, community gas utilities that feed 1.5 million supply points.

Japanese gas import companies procure more than 90% of their LNG under long-term contracts. They are preparing to meet expected growth in natural gas demand by concluding additional long-term contracts with new gas development projects. In addition, these companies import natural gas under short-term contracts or on a spot basis in the event of a sudden demand expansion due to factors such as severe winter weather, or unexpected power outages.

Although most pipelines in Japan are owned by gas utilities; some power utilities and domestic natural gas producers own pipelines as service providers. The owners are responsible for the management and maintenance of pipelines and grids. Some LNG terminals are owned individually by power utilities and gas suppliers while others are owned in co-operation through joint ventures.

LNG facilities

Japan has 27 operational LNG terminals; with 6 more planned or proposed to come on line from 2010. The country has a total import capacity of nearly 240 bcm per year, the largest LNG import capacity in the world. It also has over 14 mcm of LNG storage capacity (equivalent to 9 bcm of natural gas) held at LNG regasification terminals in above-ground and below-ground cryogenic tanks. Japan does not have underground storage of gas in its gaseous state, such as in Europe and the United States, as there is very limited availability of locations that satisfy the necessary geo-technical conditions. LNG storage in tanks is very expensive when compared to underground gas storage.

Gas market regulation

Gas production facilities and equipment, as well as gas businesses are regulated by the Gas Business Act. The use of LNG outside the scope of the gas business is regulated by other relevant laws such as the Electricity Utilities Industry Law and the High-Pressure Gas Safety Law. Regulations are enforced by the Ministry of the Economy, Trade and Industry (METI).

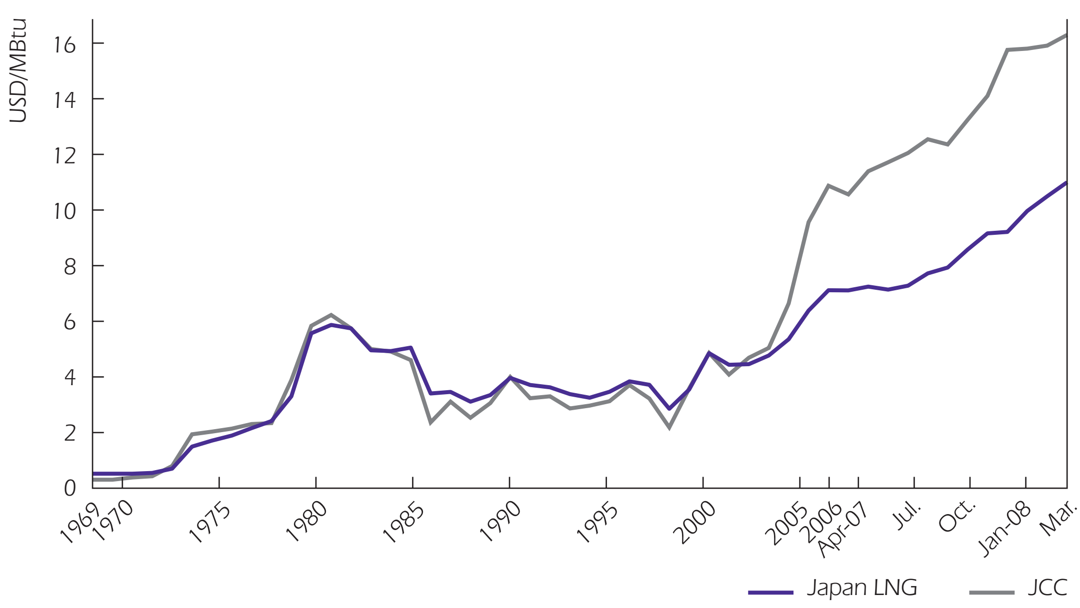
Liberalisation of the gas sector began in 1995, and has been extended such that the liberalised share of the gas market now accounts for approximately 60% of gas sold in Japan. In addition, the amended Gas Business Act, that came into force in 2004, requires all gas utilities to ensure third-party access (TPA) to their pipelines and established the category of gas pipe service provider business. The guidelines on appropriate gas trading were partially amended in order to ensure the neutrality and transparency of the third-party access system and make effective use of LNG terminals.

Prices

Historically, Japan has had higher gas prices for industrial customers than most IEA countries owing in part to the high cost of shipping natural gas over relatively long distances. When compared with the United States and Europe, there is relatively lower gas consumption in the residential sector. However, in recent years, as international prices for natural gas have risen, the disparity in prices has shrunk. Prices for residential customers, however, remain above prices for other major industrialised countries.

The fact that many long-term gas supply contracts were concluded in an era of relatively lower oil prices means that supply from these sources is currently relatively cheaper than oil. Hence the differential between current oil and LNG prices is growing. This strongly encourages gas use, most notably in the industrial sector. This

Figure 19 **Japan LNG versus JCC prices**



Source: IEA.

Note: Japan's fiscal year: April to March. Fiscal year average for 1969-2006, and monthly prices for fiscal 2007.

gap, however, is expected to narrow as LNG purchase contracts are renegotiated and producers demand higher prices.

Security of supply

Japan has been a pioneer in the import of LNG – it received its first shipment of LNG in 1969 and remains the world's largest LNG importer. Japan is also a significant coal buyer, as well as the world's third-largest importer of oil, following the United States and China, but unlike these two it has almost no indigenous fossil fuel production. With such a large reliance on imported fossil fuels, Japan has made security of supply a top policy priority. Japan's Basic Act on Energy Policy was ratified in June 2002. The act specifies that all energy policy should take due consideration of the need to secure stable energy supply, to ensure environmental suitability and to use market mechanisms. Based on this act, Japan's Basic Energy Plan was formulated in order to promote energy supply and demand measures on a long-term, comprehensive and systematic basis.

Ongoing changes to develop a more competitive gas market will enhance market signals for the private sector to secure sufficient gas supplies and allow trading across regions to improve efficiency, flexibility and security in the gas sector.

In order to enhance supply security in the event of an emergency, the government provides assistance for the construction of pipelines inter-connecting some terminals. Given the high cost of LNG storage and the country's geology, along with the difficulties of processing boil-off gas, LNG stockpiling is currently not used as a primary tool to ensure supply security as much as oil, nor is it expected to be used for this in the future. Nevertheless, Japan can rely to some degree on existing inventories – the voluntary stocks of private companies held at LNG terminals which are currently equivalent to 20 to 30 days of consumption. In addition, the government is investigating the possibilities for strategic storage (including medium- and long-term prospects for underground storage). Instead, as its primary means of maintaining supply security, the country maximises its diversity of supply sources, contract flexibility, surplus regasification capacity (which means tankers can be diverted to areas of need), and spot market purchasing.

As part of the Basic Energy Plan, the government is making long-term efforts to facilitate the procurement and internal distribution of natural gas. Given the expected increase in global LNG demand, utilities and the government are working to enhance their bargaining power with producing countries by strengthening Japan's comprehensive relationships with these countries. Beside this, Japan is making efforts to diversify supply sources in order to secure stable supply from overseas. To address the relatively underdeveloped domestic gas supply infrastructure, which lags behind other countries, and to further develop gas distribution, the government is promoting the development of gas pipeline networks and their interconnection. Third parties are encouraged to be involved in these developments through grants that give incentives for investment with the support of relevant administrative entities.

If gas supply is temporarily interrupted, Japan is able to respond through a combination of measures including the flexibility provided by Japan's diversified long term LNG supplies from eight countries:

- Voluntary liquidation of gas stocks (equivalent to about 20-30 days) by private companies;
- Use of excess supply capacity from other international LNG exporting projects (it is estimated that around 10% excess supply capacity is available in each project);
- Mutual accommodation among LNG importers, such as LNG cargo swaps, as well as LNG volume exchanges in case of companies sharing the same LNG import terminals, in the face of differing storage or demand conditions between companies.

While Japan's LNG procurement relies largely on the efforts of private companies, the government is also making efforts to diversify supply sources and strengthen its dialogue and policy interaction at all levels with gas-producing countries.

North America

The combined Canadian and United States natural gas markets form the largest integrated natural gas market in the world, with Canada providing about a quarter of the combined gas production. The market is robust, and has proven itself to be remarkably resilient in recent years. It provided reliable service through several challenges, including severe weather during hurricanes in the Gulf of Mexico in 2004 and 2005, that caused major disruptions of production and transportation facilities, lasting over a number of months.

In 2007, United States consumption was 653 bcm, up 6.5% on 2006, and the highest since 2002. This consumption was largely met from domestic sources (547 bcm), with the balance coming from LNG imports (almost 22 bcm) largely concentrated in the period from March to August) and pipeline gas, 110 bcm, from Canada.

Recent market evolution

Prices continued to rise over the year to average nearly USD 7 per MBtu, more than double those of 2002. The year 2007 saw a near doubling of oil prices. Despite this, North American natural gas priced at Henry Hub was much less volatile, averaging around USD 7.11 per MBtu for the near-month contract most of the year, about 3% above those in 2006. High storage levels were a key factor in stabilising prices.

However, since late 2007 and into early 2008 significant rises in gas prices have occurred. The average spot price at Henry Hub for the first quarter of 2008 was USD 8.66 per MBtu with prices exceeding USD 10 per MBtu on a number of occasions. As markets enter the shoulder season, or the period between winter and summer when storage operators refill gas storage in advance of the next winter period, prices are often quite weak. However, prices have continued to rise steadily in 2008 to over USD 13 per MBtu in the second quarter. Although supply has responded strongly, demand has also been robust.

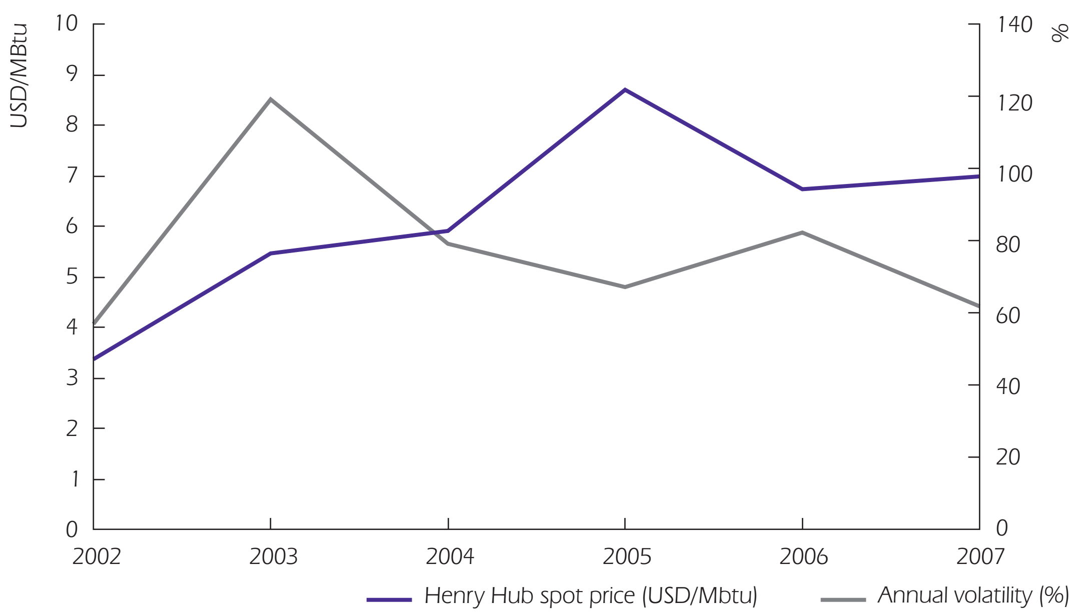
Figure 20 **Evolution of Henry Hub prices**

Source: ICE.

The impact of these changes has been seen in both imports of gas and changing usage patterns. Natural gas was significantly cheaper than oil for the same heat content in most parts of North America over 2007. These factors influenced gas consumption in three ways; firstly more gas was consumed by gas-fired power generators; secondly, plants capable of switching fuels ran on gas where possible; and finally, domestic consumers used more gas to heat their homes over the winter months (winter months of 2008 were the coldest for seven years).

With the development of Rockies Express pipeline, a major and persistent price difference between producers in the Rockies and customers in the West and Midwest of the United States can be eliminated (see also Investment in new supply projets chapter). Currently, the largest remaining price disparities in the United States generally occur in the northeast. During severe winter weather, New York and New England have long seen occasional periods when local prices rose far above those of other regions, including Henry Hub. Over the month of December and into January 2008 prices in the northeast averaged USD 11.51 per MBtu and reached peaks of USD 17.50 per MBtu at times, compared to an average of USD 7.12 per MBtu at Henry Hub over the same period. In 2007 alone, gas prices in the northeast were at least USD 5 higher than those at Henry Hub on 30 separate days. By contrast, in the six years before 2007, north-eastern prices were that much higher than the Henry Hub for a total of only 33 days.

Figure 21 **Decline in price volatility despite higher prices in the United States**



Source: EIA.

Prior to 2007 wholesale natural gas prices over previous years had been volatile, fluctuating significantly on a daily basis as well as displaying erratic monthly and seasonal price averages. Market tightness has led to spot prices responding quickly and sometimes significantly to even relatively small changes in demand, transportation constraints or other market conditions. Prices are driven by market conditions that include high crude oil prices, a growing natural gas production response (especially for unconventional sources) relative to record drilling levels, continued strong demand, and ongoing vulnerability to major supply disruptions such as hurricanes in the Gulf of Mexico region.

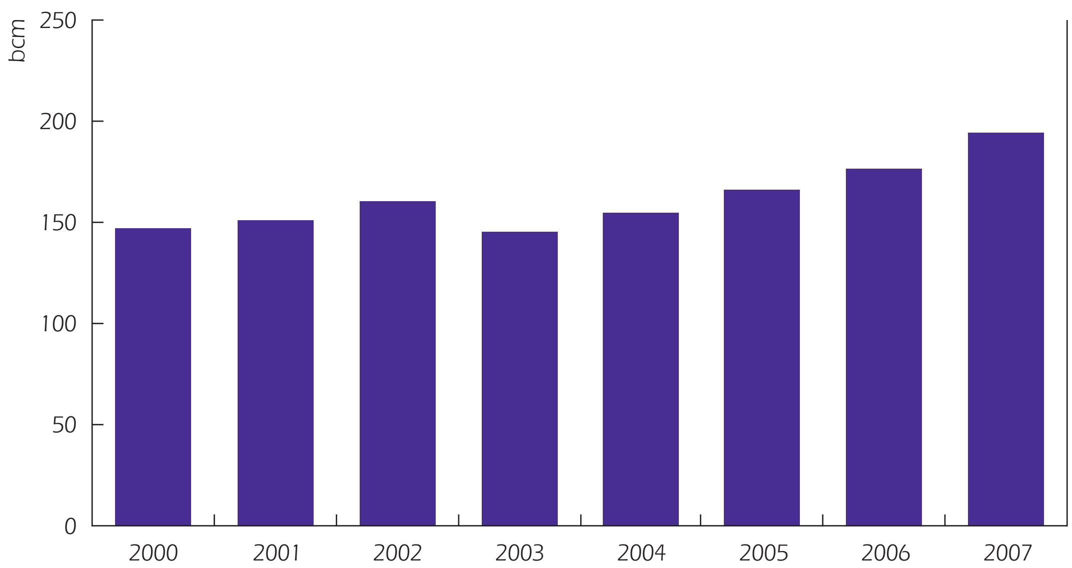
Markets demonstrated less volatility in 2007 than had been the case in recent years. This reduced volatility is a reflection of the absence of supply disruptions and the subsequent recovery periods that had been a feature of recent years' markets. The availability of LNG in the earlier part of the year and large volumes in storage also impacted on prices. The difference between the maximum and minimum prices over the year was also the lowest since 2002.

Consumption

Natural gas consumption in the United States was up 40 bcm in 2007 when compared with the previous year, the first year-on-year consumption increase seen since 2004. All sectors of the gas consuming economy saw higher use but the greatest increases were in the power generation and residential sectors. Electricity generators burned a record 194 bcm of gas last year up 10 % on the previous year. Residential gas consumption was significantly up in 2007 (8.2%). Consumption in the first quarter of the year was up 10.8 % despite mild temperatures, a pattern repeated in November and December 2007. Growth in the industrial sector was less spectacular at 2.1 %, perhaps reflective of the current trends within the overall manufacturing economy, but also highlighting this sector's greater sensitivity to the price increases seen in recent years.

The large increase in power generation demand is partly due to the large levels of gas capacity additions in 2007 as well as to markedly hotter summer weather. Although the overall level of capacity additions in 2007 was down on previous years, almost 11 000 MW of new gas capacity was added over the year, accounting for almost half of capacity additions. Gas became the number two source of electricity generation in 2007, ahead of nuclear but behind coal. Capacity additions of approximately 70 000 MW are planned over the period 2008 to 2011 of which a little over half, or 36 000 MW, are gas-fired (compared to 43% or almost 30 000 MW for coal) in all likelihood increasing the importance of gas-fired power in the medium term. Plans for incremental coal capacity often evolve into incremental gas additions as siting and permitting remain problems for coal. The Federal Energy Regulatory Commission (FERC) has attributed the slowdown of investment in new generation on the uncertainty about the future treatment of greenhouse gases, especially carbon dioxide and has cited the cancellation of many proposed coal projects in 2007 as testament to this view.

Figure 22 **United States' gas consumption for power generation**



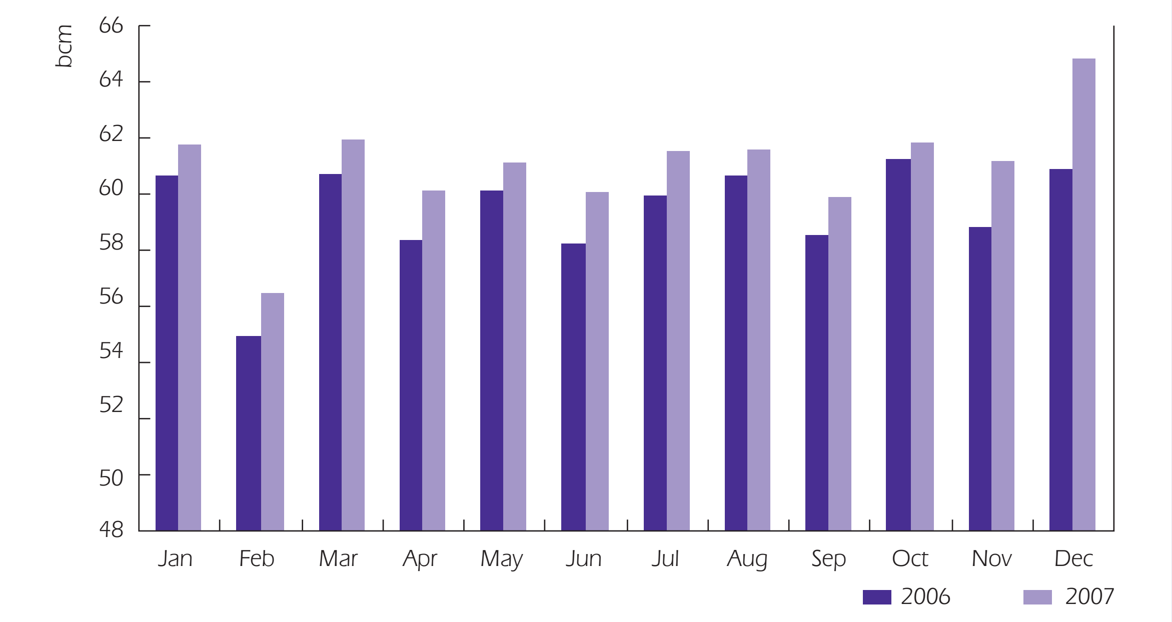
Source: IEA.

Natural gas production

Indigenous production in the United States in 2007 was up 4.3%, or 23 bcm, on 2006 levels reaching 547 bcm, the highest level of production recorded since 2000. Canadian production in 2007 was 183 bcm, down 2.7% on the previous year. Canada exported 60% of its total production to the United States.

The continued decline in production from the Federal Gulf of Mexico was evident for the sixth consecutive year, notwithstanding the connection of the 10 bcm Independence Hub. Production from the region totalled 78.5 bcm in 2007 a decrease of 4.73% from the previous year. Production in the region for the first four months of 2008 has remained static at 26 bcm. Also, production in some other major producing States, such as New Mexico and Louisiana, was down on previous years. New Mexico, where output had been reasonably constant over the previous six years, recorded a 6.3% decrease in production down from 46 bcm to 43 bcm. However, these reductions were offset by substantial gains in Texas, where a 10.5% increase over 2006 production levels was recorded taking production to 173 bcm and Oklahoma, where production rose 6.8% to 51 bcm. Production increases were most marked at the end of 2007 and have continued into 2008, with production in Texas up just over 15% over the first four months of the year and up 6% in Oklahoma, as producers have responded quickly to prices in the USD 10-11 per MBtu range. First quarter production in the United States in 2008 increased 9% when compared to the corresponding period

Figure 23 **Gas production in North America**



Source: IEA.

in 2007. This gas is increasingly being sourced from unconventional sources (see later section on New Technologies), such as the Barnett Shale in Texas. If this trend continues it will have global significance as it will reduce United States' demand for LNG imports.

According to data published by Baker Hughes[15] the increase in onshore production occurred as the number of rigs drilling natural gas prospects peaked late summer and then levelled off after a slight fall, ending an upward trend that began in mid 2002. The levelling off occurred largely in the final quarter of the year when weekly rig counts were below levels observed in the summer and at times below those of the same time the previous year.

The average number of rigs drilling for natural gas was 1 465 in 2007, which was approximately 94 rigs more on average per week than in 2006 or roughly 80% of all drilling activity in the United States. The numbers of rigs drilling set a new weekly record in 2007, reaching 1 523 for the week ended August 31. Meanwhile, the number of rigs drilling for natural gas offshore decreased over the year reflecting the trend of falling output in the Federal Gulf of Mexico region. Conversely rig numbers in Texas and Oklahoma showed increases in drilling activity consistent with increased output.

In Canada the average weekly number of rigs drilling for gas was 215, down significantly from the 2006 average of 359 rigs per week. The great bulk of Canadian drilling occurred in Alberta with the majority of the remainder in British Columbia and Saskatchewan. In contrast to the United States, production was down nearly 3% over 2006, although export growth remained strong.

In Canada, the Western Canada Sedimentary Basin (WCSB) – an area that includes most of Alberta and parts of British Columbia, Saskatchewan, and Manitoba – accounts for almost all Canadian output. Output increased by more than 60% over the 1990s. Increasing natural gas prices in recent years have motivated increased drilling activity in the WCSB, even though average returns from each well have declined. Producers in the WCSB have been experiencing difficulty in maintaining natural gas output in an environment of rising production costs and declining well productivity. Even as Canada has been experiencing these supply strains, Canada's domestic natural gas demand for oil sands operations in Alberta and for gas-fired power generation in Ontario is increasing, also tending to make less natural gas available for export.

Imports and LNG

Total natural gas imports to the United States reached a record high of 130 bcm, an increase of 10% over 2006. Increases in both pipeline imports from Canada and seaborne LNG contributed to the increase. The volume of natural gas imports in 2007 continued to equal about 16% of United Sates natural gas consumption, a ratio that has remained relatively stable throughout the past decade.

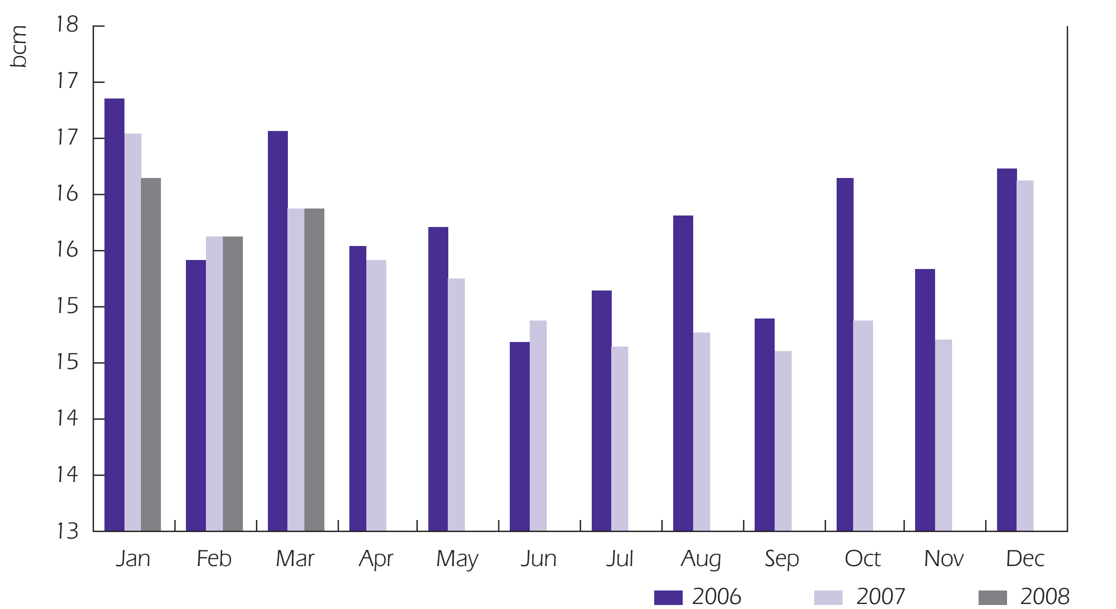
15. US Rig Report for March 28, 2008 - Current & Historical Data, Baker Hughes.

Canada is the third-largest producer of natural gas in the world and the number one supplier of natural gas to the United States accounting for 82% of all United States imports. Canada produced 183 bcm of natural gas in 2007 and exported 110 bcm to the United States, an increase of 7.7 bcm or 7.6% over 2006. Small volumes of gas, 12.24 bcm, also moved from the United States to Canada over the year and these volumes represent over half of all United States gas exports over the year.

United States LNG imports reached a record high of 22 bcm, which was 32% higher than the previous year and well above the previous high of 18.45 bcm recorded in 2004. This increase, however, fails to tell the full story as imports of LNG were very high over the period from March to August 2007 but fell sharply in the final third of the year. The United States received record amounts of LNG over the first two thirds of the year partly because United Kingdom and Spanish prices were lower than American prices, and partly because of the huge demand from power generators and domestic customers. Essentially, Henry Hub played the role of swing consumer as spot prices provided an opportunity. This trend reversed in the latter third of the year as competing markets offered higher prices and by December the United States had the lowest LNG imports for any month since 2002.

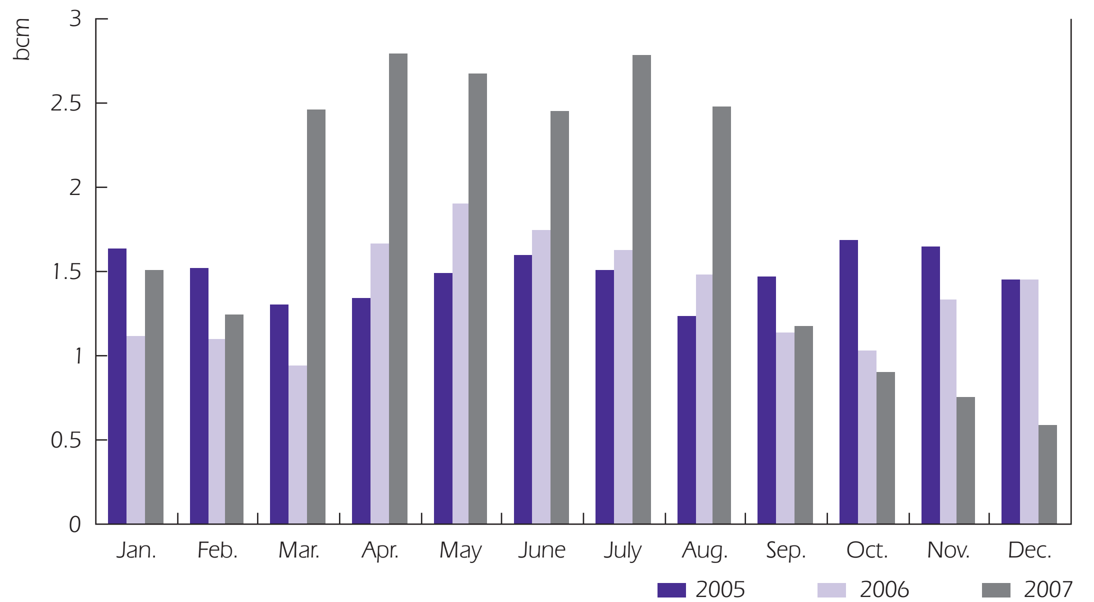
LNG imports to the United States were sourced from six different countries in 2007 as compared to the four that provided supply over the previous year. Trinidad and Tobago remains the largest source with 58% of total annual LNG imports.

Figure 24 **Canada natural gas production (2006 - 2007)**



Source: IEA.

Figure 25 **Annual LNG imports to the United States**



Source: IEA.

Imports from Trinidad and Tobago reached record levels following the expansion of liquefaction capacity at the Atlantic LNG facility at Port Fortin. With the completion of the 7.1 bcm Train 4 in December 2005, the total production capacity of Atlantic LNG is more than 20 bcm.

Egypt and Nigeria remained important sources of LNG imports over 2007. Egyptian imports were down slightly at 3.24 bcm while Nigeria increased its exports by 66% to 2.7 bcm. Smaller volumes were received from Equatorial Guinea and Algeria while spot volumes arrived from Qatar.

Five LNG import terminals operated in the continental United States during the year. Southern Union Company's Trunkline LNG terminal in Lake Charles, Louisiana, received the largest volume of any United States terminal with receipts totalling 7.1 bcm. The Everett, Massachusetts, facility (owned by Suez Energy North America) received the second biggest volume at 5.2 bcm.

The Everett facility received shipments at a relatively constant rate during the year as did Elba Island, Georgia, which is supplied under long-term contract arrangements. However, the other facilities received LNG shipments that varied in size throughout the year, with peaks for the year occurring during June through August. The pattern of United States's LNG imports reflected the pattern of global demand during the year. A mid-year increase in deliveries occurred at a time of relatively low demand for LNG in other parts of the world.

Canaport LNG is constructing an LNG receiving and regasification terminal in Saint John, New Brunswick. The 10.3 bcm facility will begin operations in late 2008, becoming the first LNG regasification plant in Canada.

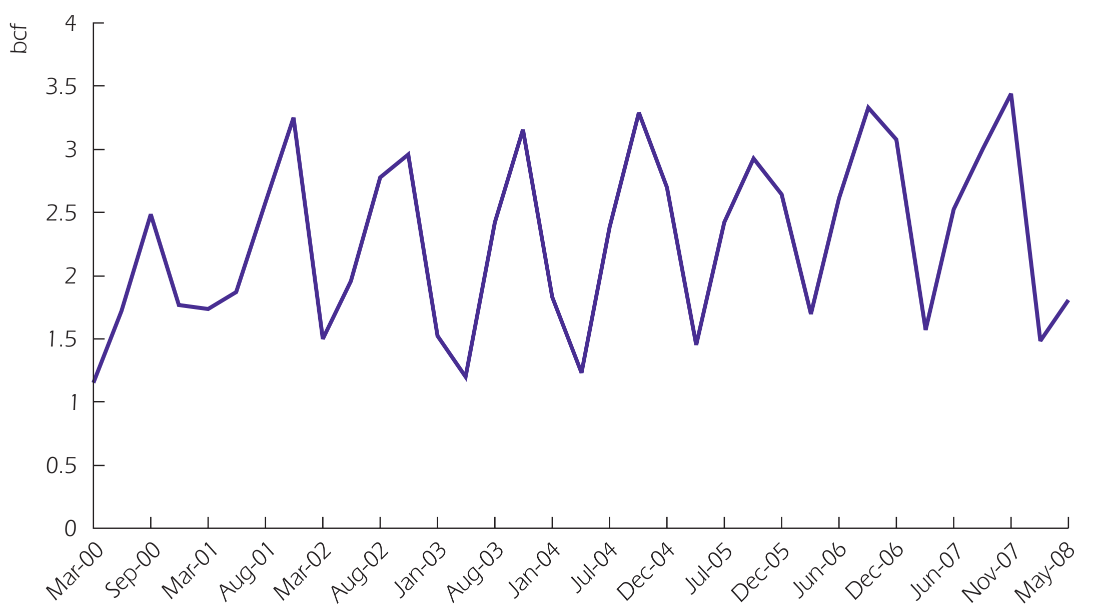
Storage in the United States

Recently, the Energy Information Administration (EIA) estimated a maximum effective working gas storage capacity available in the United States of 110 bcm. Most existing gas storage in the United States is in depleted natural gas or oil fields, because of their wide availability. Conversion of a field from production to storage duty takes advantage of existing wells, gathering systems, and pipeline connections.

In some areas, most notably the Midwestern United States, natural aquifers have been converted to gas storage reservoirs. The large majority of salt cavern storage facilities have been developed in salt dome formations located in the Gulf Coast states. Salt caverns provide very high withdrawal and injection rates relative to their working gas capacity.

Gas storage levels for the six years from 2002 to 2007 have averaged over 90 bcm at the start of the heating season at the beginning of November. Since 1998, an inventory of underground natural gas storage in the United States has developed in response to market requirements for the service. Over the past years, little or no operational disruptions have occurred in the natural gas market place as a consequence of a lack of either working gas capacity or injection/withdrawal capability. Up to 2010, more than 83 additional underground natural gas

Figure 26 North America storage inventories



Source: EIA.

storage projects have been proposed for development. Completion of these projects would represent a 6% increase in working gas storage capacity in the United States by the end of the decade.

Despite the higher consumption of natural gas, particularly during the heating season months, natural gas storage inventories were relatively high throughout 2007. At the beginning of 2007, natural gas inventories were 87 bcm, the highest level since 1982 when inventories started the year at similar level. Working gas in storage continued to exceed the five-year average inventories throughout the year, at times exceeding the previous five-year (2002-2006) maxima. High storage inventories at the onset of 2007 underpinned above-average stocks during the year, keeping downward pressure on prices through much of 2007. Net withdrawals during the year exceeded the five-year average withdrawals by about 11%.

Infrastructure development

Traditionally the United States interstate pipeline system has expanded quickly to meet changing patterns of supply and demand. A large number of natural gas pipeline projects were completed in North America in 2007 with the majority of the pipeline additions in the United States. According to the preliminary data provided by the EIA, a total of 51 pipeline projects with a value of USD 4.1 billion were realised in the United States, adding a total capacity of 155 bcm per year. The added capacity was 18% higher compared to 2006 and almost doubled the added capacity of 2005.

The most important projects include:

- New phases of the Rockies Express (REX) Pipeline linking Wyoming and Colorado gas production to markets in the upper Midwest. REX West began service in January 2008 and levelled prices between Wyoming and the Midwest. Historically, Wyoming prices often fell to low levels, even reaching one cent per MBtu when the Cheyenne Hub was disrupted.

- Improved connection between East Texas and Louisiana across the traditional barrier of the Sabine River. Combined, these projects now move volumes of incremental gas from East Texas to eastern markets and have reduced the price differences between East Texas and Louisiana.

- Independence Hub connects up to 10.3 bcm per year of new production in the Gulf of Mexico with onshore pipelines.

- Cypress's initial phase connects LNG supplies at Elba Island, Georgia, to northern Florida, providing new supply for the growing Florida market, especially in the summer months. The pipeline, originally planned in 2000, adds diversity to Florida's supply, a key consideration after the hurricanes in 2005.

During the period 2007 to 2010, the United States' natural gas industry is expected to almost double its level of investment in pipeline infrastructure upgrading compared to levels seen between 2002 and 2006, providing a 13% deliverability increase. Pipeline companies have proposed nearly 200 projects that could provide significant additional capacity to the national network by the end of the decade. Much of the planned expansion is based on the presumed need to serve growing markets for electric power generation, particularly in the west, where utilisation levels on pipelines delivering gas to California have exceeded 95% on a continuing basis.

While capacity additions were a common occurrence in the United States this was not the case in Canada. Currently the network has adequate capacity in place on existing natural gas pipelines. Most National Energy Board (NEB) regulated gas pipelines have some excess capacity, even during the peak winter season. Pipeline utilisation declined for most pipelines in 2007. Stagnating or declining conventional supply from the WCSB, growing demand within western Canada, and competition from other supply basins, particularly in the western United States, resulted in reduced flows on pipelines transporting gas from western Canada.

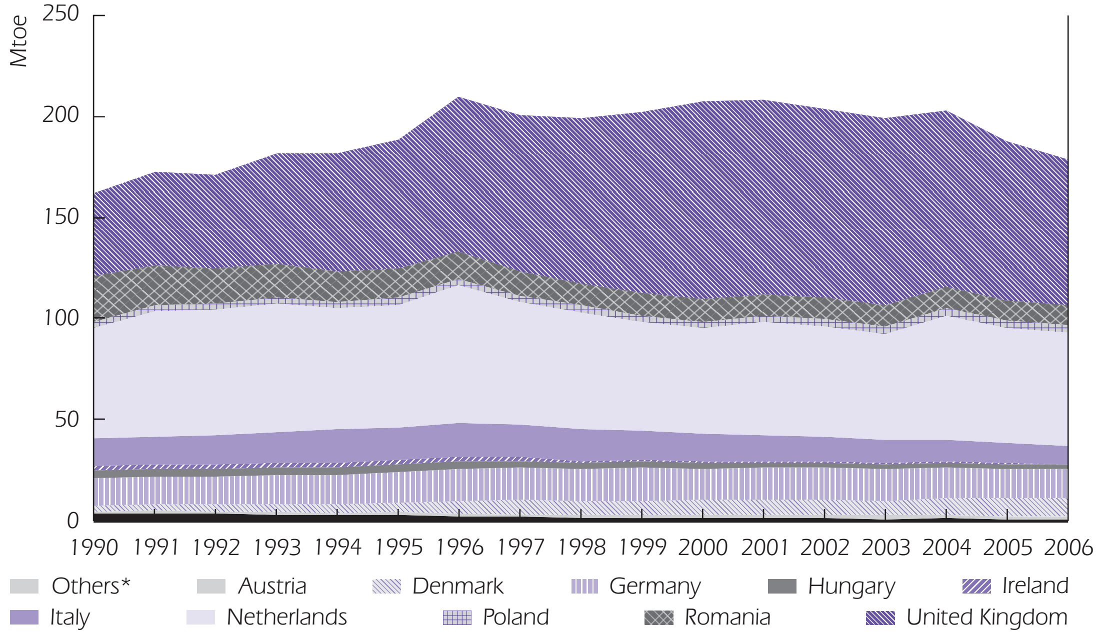
European Union

Within the European Union (EU), gas production, supply and user infrastructure have tended to be developed on the basis of individual countries' own reserves, and in relation to diverse national energy policies. Hence gas use tends to vary markedly between countries both in its contribution to total primary energy supply (TPES), and in final consumption. Because of this historical growth pattern, cross border trade, except for transit agreements, has only grown slowly even when domestic supply has declined. A notable exception is the Netherlands, where international gas trade has been an important feature of that country's gas development. The European gas network has been built along major transit routes, east-west with Russian gas imports and, for Western Europe, from the north with Norwegian and Dutch gas supplies, and from the south with Algerian and Libyan pipelines. Within the EU, internal non-transit interconnections are underdeveloped and frequently congested.

Thus while it is difficult to generalise on gas use within the EU, some broad observations can be made. Natural gas has been an important source of energy diversity in EU energy supply, growing from 10% of TPES in 1973, to 18% in 1990, and 25% in 2005. In the period between 1990 and 2005 gas use grew by 50%. The United Kingdom, Germany and Italy are the major gas users. The importance of gas in TPES varies from, for example, 23% in Germany, to 35% in the United Kingdom, Italy 38% and Hungary 42%. In Spain, gas has moved from barely 8% of TPES to 22% over the course of the decade to 2006.

Gas provides some 28% of industrial energy needs EU wide, and more than a third of residential and commercial needs, being especially important in space heating. In the power sector its role has increased sharply from barely 7% of power output in 1990, to 16% in 2000, and more than 20% in 2005. Moreover, this trend is expected to continue, growing further to 25% by 2010, and becoming the second most important source of power behind coal and ahead of nuclear. By 2020, gas-fired power output is forecast to reach 1100 TWh, up from 660 TWh in 2005. In Italy, gas accounted for 44% of power in 2005, and is forecast to grow to over 60%

Figure 27 **EU-27 gas production**



*Others include Belgium, Bulgaria, the Czech Republic, France, Greece, the Slovak Republic, Slovenia and Spain.
Source: European Commission.

early next decade. The United Kingdom's pattern looks quite similar, rising from nearly 40% to 60% of power generation by 2020. In Germany gas-fired power is expected to increase from around 10% to 25%, an increase of nearly 100 TWh over the next decade, a similar absolute increase to that of the United Kingdom. Gas has become the preferred choice for new power plant investment in most EU countries, and in several cases the default option, as new nuclear plants are often formally prohibited, and coal plants difficult to develop even in traditional coal using countries. Gas-fired plant has many advantages, including relatively small size and low capital cost, hence minimising risk, plus a smaller environmental and greenhouse gas footprint. Its flexible operation makes it the preferred choice to meet Europe's increasingly peaky and seasonal power demand, plus the obvious technical and economic choice to back up intermittent renewables generation such as from wind.

The accession of 12 new Member States in 2004 and 2007 has had a significant impact, particularly with regard to import patterns and where the gas is sourced. A number of these states have a high level of dependence on gas in their TPES (Romania, Latvia, Estonia, Lithuania, and Slovakia). Most of the new Member States are countries that have previously been under the Soviet sphere of influence, and receive gas mainly from the former Soviet Union, often via only one pipeline.

Supply

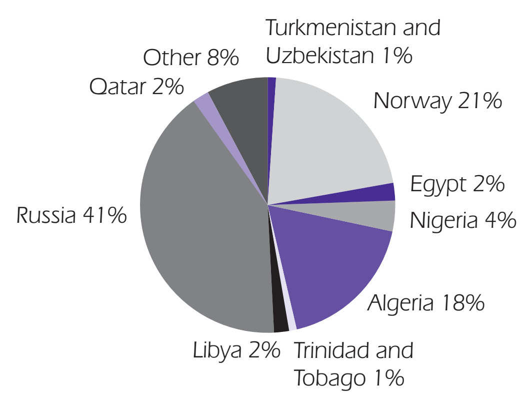
The major EU gas producers are the United Kingdom and the Netherlands, producing 70% of EU gas output. Other significant producers are Denmark, Romania, Germany and Italy producing almost all of the remainder.

EU gas production peaked in 1996, plateauing until around 2004. United Kingdom production peaked in 2000, production declining rather more rapidly than anticipated in recent years, so that 2007 output was around two-thirds of that in 2001. Recently, production falls in the United Kingdom have averaged between 8 and 10% per annum reducing gas output in 2007 to 76 bcm. This trend seems set to continue, with EU production dropping in line with its mature status; falling around 12% in 2005 – 2007, to the point where 2020 output is expected to be about 56% of 2004 production.

Natural gas imports

Gas imports have been an important feature of Europe's gas supply for some decades, firstly from Russia, via pipelines through Ukraine and Czech and Slovak Republics, and more recently Belarus and Poland. Pipeline imports arrived in southern Europe from Algeria in the early 1980s. Norway started exporting gas via pipeline in the 1970s, but has recently sharply raised volumes by around 70% (or 35 bcm) between 2001 and 2007, to 85 bcm. In early 2008 exports rose by nearly 20% compared with the same period in 2007. LNG has become a more prominent import vector in recent years, notably in Spain. By 2005, the EU imported 57% of gas consumption. Main import sources for gas supplies to Europe are Russia (24% of consumption), Norway (15%) both by pipeline and Algeria (11%), by both pipeline and LNG. LNG imports were about 13% of total gas needs, with the major suppliers being Algeria, Libya, Qatar, and Nigeria.

Figure 28 EU gas imports (2006)



Source: EC.

Pipeline import routes to the EU are mainly from Russia directly and via Ukraine and Belarus, from Norway, from Algeria via Morocco and Tunisia, from Libya, and from Iran/Azerbaijan via Turkey. The total annual entry capacity is about 375 bcm. The EU has 14 LNG terminals in operation with a total capacity of around 103 bcm. Gross import capacity is thus almost 480 bcm, with most of the unused capacity on the lines from Russia. This is probably sufficient to meet import needs up to early into the next decade, at least on an annual basis. New supply projects are being built, notably pipelines from North Africa, and a significant number of new or expanded LNG terminals, with further proposals being advanced (*e.g.*

new pipelines from Russia and the Caspian region and additional LNG capacity, notably in Northern Europe).

By 2015-2020, LNG imports could be between 120 - 140 bcm, more than double current levels. IEA analysis indicates that the demand for gas imports by pipeline could be as high as 400 – 420 bcm per year by around 2020. Norwegian exports then are likely to be around 120 bcm, although the resource base could probably supply more. Pipeline supplies from North Africa and Russia, plus other new sources, would therefore need to make up 280 - 300 bcm in 2020. In 2005, total imports from Russia, Algeria and Libya were respectively, 140 bcm, 37 bcm, and 5 bcm, for a total of 182 bcm. Gas demand projections are uncertain however, and it is possible that achieving the EU's March 2007 energy policy commitments could reduce projected volumes, if additional, for example renewable capacity, replaces natural gas.

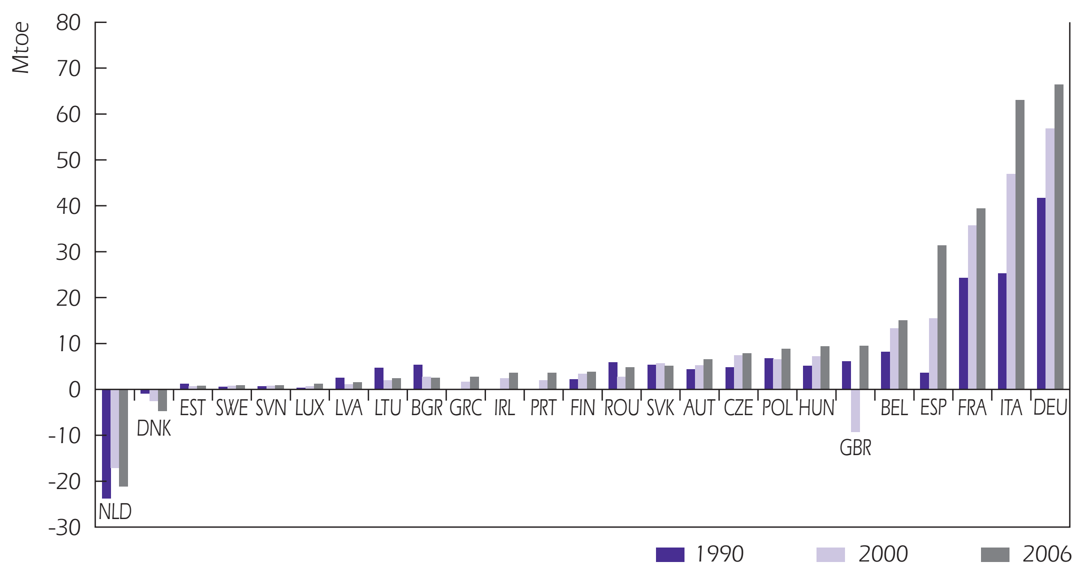
Exports

Internal exports of gas within the EU total around 80 bcm, and are dominated by the Netherlands, accounting for nearly two thirds of the total. These can be expected to decline by the middle of the next decade. United Kingdom, Denmark and Germany account for almost all of the remainder, with the United Kingdom and Germany being net importers.

Outlook

Clearly the outlook is for gas to play a growing role in meeting EU energy needs, and for a growing relationship with the

Figure 29 **EU-27 net imports of natural gas**



Source: Eurostat.

electricity sector. Gas prices will almost certainly determine electricity prices in large portions of EU markets for much of the year. Gas and electricity security will become increasingly intertwined. At the same time EU production will decline further and imports will rise, to 63% of supply in 2010 to 77% in 2020, in net terms up from about 320 bcm in 2004 to some 540 bcm in 2020.

Infrastructure

The increasing need to import gas necessitates not only additional supply infrastructure but also greater interconnection between EU countries to enable the large increments of imported gas to be absorbed efficiently within Europe, and to provide access to LNG supplies to countries without seaborne terminals.

While a number of new importing projects are planned to meet Europe's growing needs, few internal network interconnections are being built. Regional market integration is a prerequisite for a successful competitive market – for example, inter-state integration in the United States market allowed substantial increases in regional hub development and supply competition. In the European Union, the "gas islands" of south-east and north-east Europe are not interconnected to the necessary extent and existing interconnections often constitute bottlenecks at a regional market level. An increase in internal interconnection investment will benefit overall competition levels within the European market and contribute to security of supply.

An additional factor concerns storage. Currently EU storage capacity is relatively high; covering about one seventh of annual demand, compared to North America's one-fifth. Within this gross figure, significant variation exists between countries, with Germany, France and Italy with high storage levels, while other countries are less well supplied (*e.g.* Belgium, Spain or the United Kingdom). This reflects, a lack of suitable geology, plus a recent history of available production able to supply swing volumes. There is also a large variation among countries in the type of storage, between depleted oil and gas fields (generally more suited to seasonal drawdown) and aquifers and salt caverns (more suited to the fast draw down that gas-fired power generators may need).

Storage investment in many EU countries has been slow and remains inadequate in some areas, because of a combination of local environmental problems, or planning issues, plus lack of suitable geology, or lack of market signals, such as variation in seasonal or diurnal prices. The latter is connected to the linking of gas prices to oil prices, which disconnects them from market fundamentals – a situation that is fundamentally different from that in other IEA gas markets, in particular North America. The declining ability of domestic production to respond to demand swings as production declines, plus the need to respond to sharper demand changes as gas becomes more important in the power generating system, means that the EU needs to build more diverse storage, preferably close to consumers. Geographical concentration of storage need not be a problem as long as the EU market can flexibly move gas to markets where it is needed. However, recent experience shows this is not currently the case.

Market reform[16]

Negotiations between the EU authorities, the Member States and the market stakeholders during the 1990s culminated in an Electricity Directive (96/92/EC) and, two years later, in a Gas Directive (98/30/EC) introducing a first set of common rules for the EU energy markets. On natural gas, the new legal framework was aimed at opening gas networks to third parties (TPA), allowing free choice of suppliers for eligible customers. This was to be achieved through unbundling of the network activities of the vertically integrated historical gas operators from the storage and retail functions, thus allowing retail competition through the natural monopoly network. The EC encouraged the industrial reorganisation within each country to be supervised by an independent regulatory authority, but this was not mandated.

The EU member states could (and did) choose different approaches to implement these reforms, negotiated or regulated TPA, accounting unbundling, legal unbundling or complete separation, and ex-ante or ex-post regulation of the market. However, overall equivalent economic results and market opening were required between national markets. Derogations were possible if:

- the reforms were contrary to existing public service obligations, to long-term take-or-pay obligations, to security of supply prerogatives, or were likely to create other economic difficulties;
- the national or regional market was not sufficiently interconnected with other EU markets, or had only one external supplier and no indigenous resources;
- the national or regional market was in need of substantial investments (as in the case of emerging and developing markets).

In practice only two countries asked for such derogations, Luxembourg and Greece.

The analysis made by the Commission on the implementation of the First Gas Directive revealed an unequal level of market opening, tariff and third party access problems, concentration of gas production and imports. For these reasons, competition at this stage was not effective, and consumers were seeing little benefit. Further structural measures and full market opening were deemed necessary in order to advance towards the initial objectives of lower prices and efficient markets. The Commission deemed the outreach of this First Directive insufficient as few signs of effective competition were seen.

The EU Council at Barcelona in March 2002 decided on full market opening for industrial gas consumers in 2004 while total market opening was intended for 2007. A year later, the Second Gas Directive was adopted (2003/55/EC). Concomitant to a Second Electricity Directive (2003/54/EC), the new EU gas law mandated regulated TPA as the basic rule (for all existing infrastructure) as well as moving the level

16. This section is partly based on the IEA information paper "Development of Competitive Gas Trading in Continental Europe", published May 2008.

of unbundling of transmission system operators (TSOs) to the level of legal (but still not full) status. The role of independent regulators was also reinforced.

The subject of pipelines in the liberalisation process was handled with caution – new pipeline projects were granted a possible temporary exemption from TPA in order to make the investment attractive. But the question of whether temporary TPA exemption would be sufficient to trigger the necessary investment to meet growing demand and import needs, and to develop the much needed pan-European gas networks, remained unresolved.

By 2003, it was increasingly clear that competition in Europe was still very slow to develop. A new series of benchmarking reports made by the Commission in 2004 and 2005 (third and fourth) pointed out a number of issues that seemed to impede the creation of a truly competitive and functioning energy market in the EU:

- In the absence of increased interconnection, new suppliers were not able to enter markets, and gas could not circulate freely from one point to another;
- Competition between suppliers was difficult to achieve on a national basis where one import source often dominated the market (to the extent that a wider European natural gas market could be created, this concern might be alleviated);
- Prices had not fallen as expected, while regulated end-user prices distorted market functioning;
- Investment was an issue, especially in cross-border interconnections;
- The industry structure was far too concentrated, and TSOs were not sufficiently independent.

In particular, long term take-or-pay contracts were singled out as a problem, contributing to market foreclosure. The Commission also recognised that reforms were being enacted legally, but that some member states were (perhaps intentionally) reducing their effectiveness, noting that "member states need to give careful consideration to ensure that in their implementation of the Directives in practice, they pursue their spirit and not only their letter". On the positive side, a number of import projects, including LNG terminals, were progressing.

The sixth benchmarking report was issued in January 2007 and provided a global overview of the future energy policy of the EU. It envisaged a "third package" of legislative proposals for the European gas and electricity markets, which emerged in September 2007. Key features of the 2007 report were:

- A high concentration in the sector;
- A high degree of vertical integration. In particular, the fundamental conflict that arises when new large suppliers seek to use pipelines in competition with the network owners;
- A lack of transparency, especially on sensitive pipeline or gas storage capacity, actual storage levels and flows;

- A market still built on national lines with little integration, consequent lack of incentives for existing incumbents to invest in expanded network, supply or storage capacity, especially if that brings competition to markets.

The EU Commission proposed tough measures such as complete de-integration of the gas operators through ownership unbundling of the transportation, distribution and storage functions and the creation of a European regulatory agency. Proposals were also advanced to break down the technical barriers to facilitate cross border gas flow, through greater co-ordination of system operators. On a practical level the solutions put forward concerning investment between national markets and TSO cooperation are left to the Member States' bilateral cooperation and initiatives.

Cross-border trade is a key pillar for putting competitive pressure on prices. Against this background, sufficient network capacities are one of the main drivers for allowing liquid trade. Thus investments are needed to overcome bottlenecks. The EC has undertaken a number of activities under the umbrella of the Regional Initiatives with the operational support of ERGEG[17], *e.g.* the South and the South East Gas Region.

Security issues have become more prominent in gas discussions, but by no means undermine the argument for urgent progress in market reform. On the contrary, interconnections such as those described above also strengthen the resilience of the EU gas grid, its ability to absorb both supply and demand shocks. The EU supports the development of new pipeline projects that are of European interest and contribute to diversification of sources and/or route via TEN-E (Trans European Networks-Energy programme). The development of LNG terminals, contributing to the diversification of sources is supported mainly through TPA waivers. In the case of an EU emergency the directive foresees an EU coordination mechanism (emergency action plan) to be defined. The Gas Coordination Group, established in 2006, is the platform to discuss EU relevant security of supply developments; it is lead by the European Commission. Dialogue with supplier countries plays an important role.

One additional step on the way towards competitive energy markets was achieved on 1 July 2007 with the full opening of national retail markets. From a legal perspective all European consumers are now able to choose their supplier and benefit from competition. Retail markets are not yet well developed, mainly because of limited access to gas supplies for new entrants. Entry of new producers to the supply portfolio remains essential for both competition and security of supply. LNG plays an important role in this respect. While the rates of larger customers switching continue to rise, small business customers and households in most cases still have limited possibilities to exercise their right to choose a supplier.

17. The European Regulators' Group for electricity and gas (ERGEG) is an Advisory Group of independent national regulatory authorities and assist the European Commission in consolidating an Internal Market for electricity and gas.

In summary, the process of gas market reform has now run for a full decade, with at best mixed and incomplete results, notwithstanding vigorous efforts by the European Commission to implement meaningful reform. The benchmarking report shows that many weaknesses remain in the functioning of gas markets, adding to the difficulties of spurring upstream competition between the major external suppliers. The current market circumstances show strong upward demand pressure, within the context of a tight global market for gas. Lack of investment in infrastructure – both for supply, flexibility and internal interconnection – is weakening European Union energy security, and removing a potential source of downward pressure on prices. The need for vigorous reform has never been greater, if European Commission consumers are to benefit from competitively supplied gas in a secure and reliable manner. These matters are further discussed in a recent IEA Information Paper, "Development of Competitive Gas Trading in Continental Europe" (May 2008).

Germany

Demand

Germany is the largest gas market in OECD Europe. In 2007, domestic demand totalled 97.5 bcm. Demand for natural gas decreased 2.3% when compared to 2006 (99.8 bcm). This decline in consumption is notably due to the relatively high level of gas prices and mild winter of 2006/07.

Demand outlook

Future demand in the power sector is expected to grow as there are several plans for new gas-fired power plants to replace existing power plants: 40 000 MW of all types of capacity has to be replaced in Germany by 2020, which equates to almost one third of the existing generation capacity. Despite the fact that the German government is promoting renewable energy projects and there are plans for additional coal-fired power plants, expectations are that the share of gas-fired power generation will increase, not least because of the decision to phase out nuclear power plants prior to the end of their operating lifetime. In addition, several proposed coal projects have been cancelled because of investor withdrawal as a result of rising costs and ongoing protests of project stakeholders. For example, the citizens of Ensdorf in the south-western state of Saarland successfully obstructed plans by RWE to build a coal-fired power station in November 2007. Progress on other coal-fired projects is slow because of long approval processes. This recent history of coal projects will impact on future coal replacement decisions. Demand from domestic consumers for space heating is expected to decline as energy efficiency of houses improves. Germany's building stock is already relatively efficient because of strong building codes which currently exceed the EU directive's[18] minimum requirements (for buildings larger than 1 000 m^2). Expectations are that they will continue to exceed them in future years and this will have a restraining effect on gas demand.

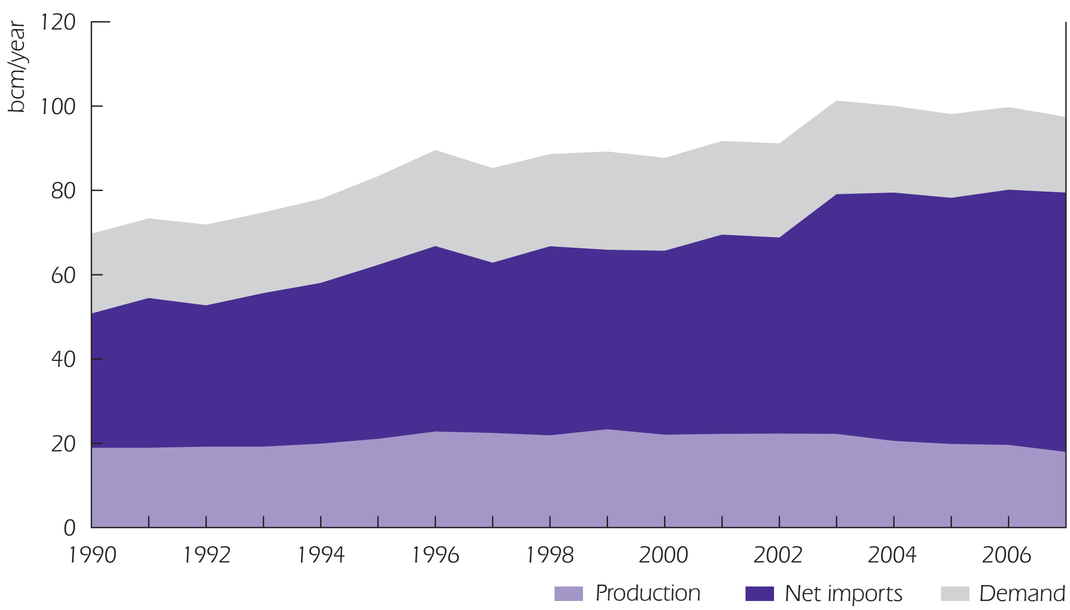
18. Directive 2002/91/EC of the European Parliament and of the Council of 16 December 2002 on the energy performance of buildings.

Development of gas demand for the industrial sector relies heavily on growing awareness of environmental concerns and related regulation and technological development. Because climate protection is one of the focal points of Germany's policies, the German government has adopted an integrated energy and climate programme. Part of this programme includes ambitious targets regarding greenhouse gas emissions. To achieve these targets, Germany has to double its energy efficiency by 2020 and significantly expand renewables. For this reason, more stringent regulation is expected to increase incentives to invest in innovative technologies and also to initiate a downward trend in fossil energy use.

Supply

Germany has the fifth-largest gas reserves in Europe after Norway, the Netherlands, the United Kingdom and Romania. Recent estimations of Cedigaz[19] show Germany's natural gas reserves are 155 bcm. Nearly all of Germany's reserves are located in the north-western state of Lower Saxony between the Dutch border and the Elbe River. Germany's sector of the North Sea also holds considerable natural gas reserves. Germany produced almost 18 bcm of natural gas in 2007, which equals roughly one fifth of current domestic demand. Production has declined slightly since the late 1990s because of difficult producing conditions and also due to

Figure 30 ***Natural gas demand and supply in Germany***



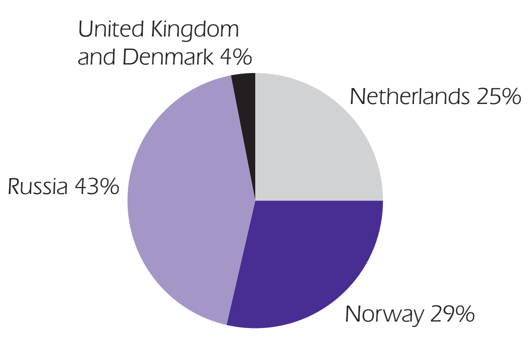
Source: IEA.

19. The players on the European Gas Market: 2008 Edition, Cedigaz, February 2008.

environmental regulations which have had the effect of reducing production in Germany's off-shore area.

Due to the interaction between deteriorating domestic production and almost static domestic demand, there has been an unavoidable upward trend in imports over recent years. Total imports in 2007 are 17% higher compared to import levels in 2000. Russia was the largest source of imports (43% of total imports), followed by Norway (29% of total imports) and the Netherlands (25%). Denmark and the United Kingdom are supplying relatively small volumes.

Figure 31 **German gas imports by origin (2007)**



Source: IEA.

Domestic production is expected to continue to decline due to production and regulatory conditions. However, the current high level of gas prices may make additional or more advanced extraction techniques viable which may counter the effect of production decline over time. Conversely, should there be no recovery in domestic production, imports will continue to increase. Anticipating this, Wintershall and Gazprom have agreed to extend Gazprom's supply contract by 35 years to 2043.

Infrastructure: pipelines and storage facilities

The total length of the German grid is about 380 000 km. Of this approximately 103 000 km is made up of high-pressure pipelines, 150 000 km of medium-pressure pipelines and 127 000 km of low-pressure pipelines. Five companies control the high-pressure gas system in Germany: E.ON Ruhrgas, Wingas, VNG/Ontras, BEB and RWE. In November 2007, BEB and Dutch gas infrastructure company Gasunie announced that BEB's 3 600 km high-pressure gas transport network will be purchased by Gasunie once German authorities approve the arrangement. New infrastructure is being considered – Nord Stream, a bilateral agreement between Germany and Russia intends to bring up to 55 bcm per year of gas from Siberian gas fields (see Investment in new supply projects chapter).

There are 14 major import entry points in the German gas network: Ellund (supplies from Denmark); Emden and Dornum (supplies from Norway); Bunde, Winterswijk, Zevenaar and Bocholtz (supplies from the Netherlands); Eynatten (supplies from the Netherlands and United Kingdom); Burghausen, Oberkappel, Waidhaus, Deutschneudorf, Olbernhau and Mallnow (supplies from Russia). Total entry capacity to the German market is 22.4 mcm per hour, or 196 bcm per year. There is limited firm transportation available at almost all entry points till 2010.

Map 5 German gas import entry points

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: Gas Transmission Europe, Gas Infrastructure Europe, October 2007, company information, IEA analysis.
Note: Maximum flow rate at Emden equals total maximum flow rate at the entry minus capacities destined for the Netherlands as per 1 January 2009.

Germany has the largest natural gas storage capacity in the European Union and the fourth-largest in the world. This capacity is spread among 47 facilities. Wingas is currently building two additional large underground storage sites, one at Rheden and a second at Haidach (at the border with Austria). The latter is being developed jointly with RAG of Austria. When complete these will be amongst the largest storage sites in Europe.

Regulation, competition and liberalisation

In 2005 a number of changes were made to energy industry legislation to help improve conditions for competition in Germany's gas markets in accordance with the European Union's second gas directive. As a result of these changes, regulation of the downstream natural gas market is carried out at federal level by the Bundesnetzagentur (BNetzA), by regulatory authorities in the individual German Länder and by the Bundeskartellamt, the Federal Cartel Office.

An initial focus of the BNetzA has been grid fees, which are currently subject to ex-ante regulation. The BNetzA has also developed a new entry-exit model; the so-called 'two-contract-model', which enables customers to transmit gas across grid levels and across grid operators within market areas with just one entry contract and one exit contract. The new system was fully implemented in October 2007, although there are still implementation problems particularly within smaller companies. The BNetzA is also responsible for supervising the implementation of unbundling of transportation and trading activities in accordance with the Energy Industry Act of 2005.

Despite the new regulatory regime, competition has not flourished. This is evidenced by recent price increases which, according to the Bundeskartellamt, would not arise in an efficient, functioning and competitive market. For this reason, it commenced proceedings against 35 gas suppliers on suspicion of abusing market power in March 2008.

Network access is the key issue hindering the development of competition. It has been very difficult to promote effective competition when incumbents control national and regional transmission networks and distribution networks remained under local authority monopoly. Lack of competition between regional players has helped maintain the rigid structure of the German market despite a 100% market opening in October 2006. Lack of transparency on capacity utilisation and very complex TPA rules have prevented new competitors from entering the market, as new entrants often find that gas or network capacity is unavailable. The storage market also suffers from similar barriers to entry.

In 2008, BNetzA is planning further changes in national regulation which could have an impact on the development of competition in the German market. For example, the regulator aims to introduce major changes to the balancing regime. At the moment, suppliers need to balance gas inputs and gas outputs on an hourly basis. Many trading companies have asked for simplified rules because there are no hourly products available on the market. Furthermore, there are proposals to cut the number of separate market areas. Many gas companies – especially those without their own networks – will welcome a decrease in the number of market areas by 1st October 2008, the start of the new gas year.

Italy

Demand

Total natural gas demand in Italy has more than doubled over the last 20 years, and from what was a locally-supplied industry the Italian natural gas market has become heavily import-dependent. In 2007 imports represented almost 90% of total consumption at 74 bcm, out of a total demand of 85 bcm, one third of which was consumed by gas-fired power plants. More than half of Italian power generation is gas-fired and this share is expected to grow. Gas demand in the industrial sector is stable, accounting for around one quarter of total demand. With a well developed distribution grid natural gas reaches nearly 90% of the population. Growth in gas demand comes from the residential and commercial sector and power generation, which currently account for 38% and 37% of the market, respectively.

The future share of gas in the residential and commercial versus the power sector depends notably on some end-user choices in the residential sector (air-conditioning), which can be supplied either with gas or with electricity. As the vast majority of new power plants in Italy are designed to be gas-fired, both end-user choices would trigger additional demand for gas. Uncertainties in most forecasting scenarios between gas for power and gas for residential customers are partly based on these future market choices.

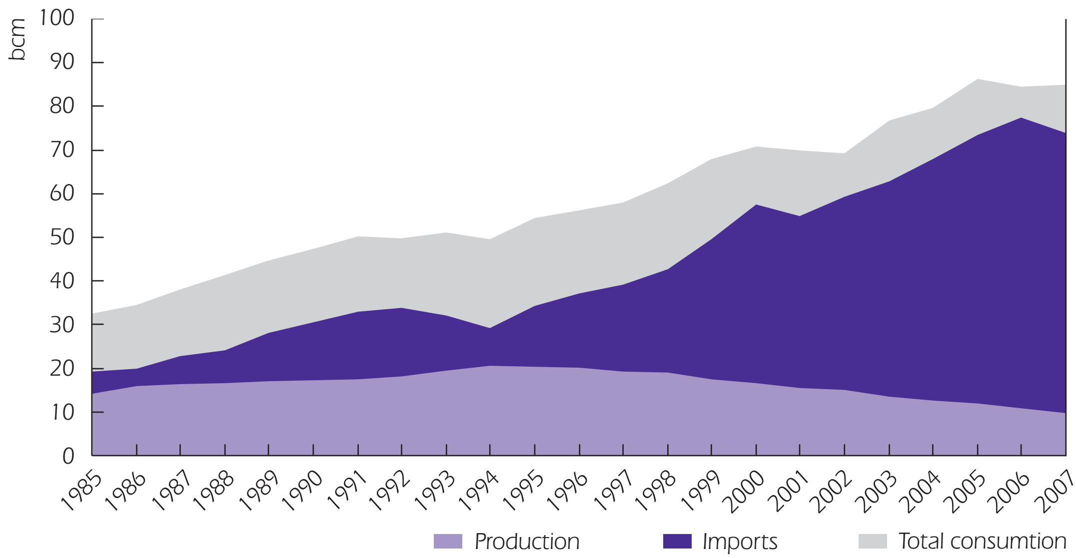
Supply

Indigenous production was first developed in the 1950s and reached a plateau in the mid-1990s. It has been declining since, while demand has been growing (by around 60% in the decade to 2005). In 2007 indigenous production was at an historical low and met approximately 12% of total consumption. As a result, gas imports have grown dramatically during the last decade. The majority of imports are provided by pipeline gas as Italy has only one LNG terminal, Panigaglia, in operation since 1971, providing only 3% of 2007 demand.

Following a slight easing in the overall gas supply and demand balance, due notably to the previous two mild winters, the supply prospects for 2007/08 were tight again. At the end of summer 2007 the government issued two gas emergency decrees intending to optimise the use of gas supply infrastructure, maximise imports and ensure demand response in the case of shortages. The first measure, previously adopted in 2006, obliged suppliers to fully use contracted import capacity between November and March. The second decree introduced interruptibility clauses for some big industrial consumers in case of gas shortage.

In 2007 half of Italian gas imports came from the North via the TAG (Russia) and TENP/Transitgas pipelines (Netherlands and Norway). The other half comes

Figure 32 **Gas import growth in Italy (1985-2007)**



Source: IEA.

from the South, via the Transmed and Greenstream pipelines (Algeria and Libya). The TAG pipeline delivered 24 bcm of natural gas (32.5% of total gas imports to Italy), the Transmed 22 bcm (30% of total gas imports to Italy). In comparison to 2006, volumes were respectively 23 bcm (29.6%) and 24.5 bcm (31.7%). The actual supplies and the contracted volumes differ due to existing swaps between Eni and other European gas operators.

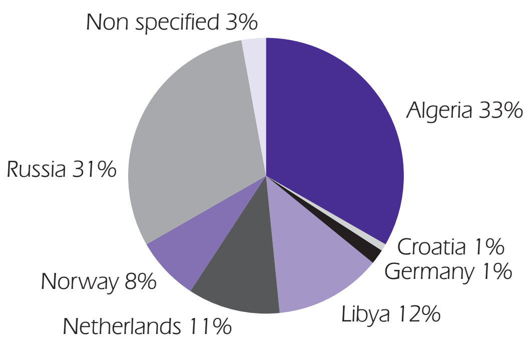
Despite numerous LNG regasification terminal projects proposed in the last decade, only one is in operation (onshore at Panigaglia) and another, in Rovigo (8 bcm per year) will commence operation in late 2008. A further offshore facility is under construction near Livorno and two proposals have received authorisation for construction.

A serious supply infrastructure gap has failed to be addressed and, for the short term, partial solutions have been utilised like upgrading existing pipelines. However, new large scale infrastructure is needed to bring additional volumes of gas to the Italian market. Supply contracts have been signed and could exceed expected actual supply; gas could then be rerouted to other European markets. These new supplies will face growing direct competition from Gazprom and Sonatrach, who have announced their intention to sell directly to the Italian market.

Infrastructure development

Currently 12 LNG terminal projects are planned or proposed. The majority of these projects are now being proposed as offshore installations. Indeed, building

Figure 33 **Origin of Italian gas imports (2007)**



Source: IEA.

onshore LNG terminals in Italy is difficult given the enduring local opposition to new infrastructure. Of these projects, only two have received authorisation and are currently being built (Rovigo, 8 bcm per year, and Livorno, 3.75 bcm per year). Other projects are awaiting authorisation. They would bring, if fully realised, nearly 90 bcm per year of new supply capacity. However, some of them compete for location and could be merged or simply cancelled due to persisting local opposition and regulatory uncertainty.

One example is the BG project at Brindisi, which had received full authorisation in 2003. In February 2003, Italian company Enel joined the project which was at that time expected to come on stream in 2007. However, Enel withdrew from the project in June 2005 and the Ministry of Environment suspended the project development in 2007 on the grounds that more environmental impact studies and local dialogue were needed. This regulatory uncertainty continues into 2008.

In 2002, it was estimated that an additional 30 bcm per year would be needed to meet demand by 2012. LNG projects were expected to fill this gap with more than 60 bcm per year of new import capacity. Instead, only the existing import capacities (Transmed and TAG pipelines) have been upgraded by 13 bcm per year in total. A decree by the Ministry of Economy published in November 2007 could ease authorisation procedures for new LNG plants, and the majority of projects (Porto Empedocle, Rosignano, Priolo, Gioia Tauro, Taranto, Zaule-Trieste, and Monfalcone) could be positively affected by this new measure.

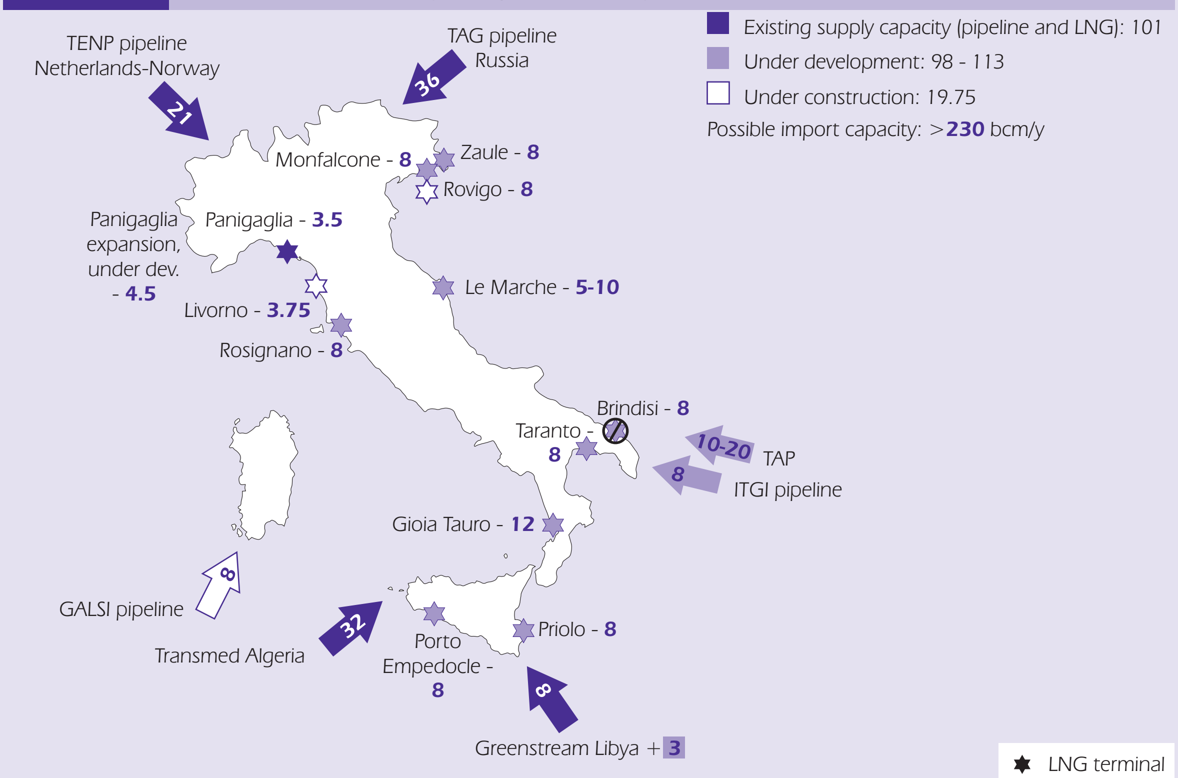
New pipeline supply projects are also being developed. A second pipeline from Algeria, Galsi, crossing the Mediterranean Sea and reaching Sardinia, should bring 8 bcm per year of additional gas by 2012, or even earlier if recent commitments by the Algerian government are realised. From the east, two projects to bring Caspian gas are being developed; one by Edison, the Turkey-Greece-Italy Interconnector (ITGI) for a volume of 8 bcm per year for Italy (11.5 bcm per year being the entry capacity in Greece); and another by EGL and Statoil, the Trans-Adriatic Pipeline (TAP), for 10 to 20 bcm per year, linking Albania and Italy. TAP comprises an LNG terminal with underground storage facilities in Albania, destined partly for the Italian market. A new link with Central Europe is also under consideration – the TGL pipeline (TauernGasLeitung) – a 260 km pipeline from Salzburg in Austria to Tarvisio in Italy that would deliver Mediterranean gas to Central Europe. A decision on this pipeline is expected by the end of 2008.

Competition and liberalisation issues

Since the beginning of European liberalisation the Italian authorities have undertaken a series of compulsory changes to the structure of the Italian gas market in order to ensure fair access to pipelines and effective competition in supply. Notably, these measures included very precise and progressive gas release programs, and ownership and market share limitations for the incumbents. However, the dominant position of Eni is still an issue for the regulatory authorities and in 2007 the European Commission commenced antitrust proceedings against the Italian gas incumbent in relation to the potential exclusion of new entrants in the Italian market. Eni is being accused of capacity hoarding and strategic underinvestment on the Italian gas transmission network, intending market foreclosure which would threaten not only development of competition but also security of supply for Italian customers.

Despite several measures aiming to restrain Eni's dominant position in the Italian market, the incumbent operator sells nearly half of all end-user gas. In the midstream sector of the market, Snam

Map 6 Gas import capacity projects in Italy



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; Ministry of Industry; company sources.
Note: all numbers expressed in bcm.

Rete Gas (still controlled by Eni) and Societa Gasodotti Italia (affiliate of Edison) are the two transmission operators. Snam retains ownership of the only operating LNG terminal. Other potential midstream players are developing new infrastructure but with marked difficulties, as outlined previously. Downstream, many district and regional utilities are controlled by local government and the segment remains very fragmented, despite ongoing concentration. The residential market is open to competition since 2003 but regulated domestic tariffs were ended only in 2007. Effective competition in this segment is practically nonexistent (very low switching rates) and new entrants acquire residential customers only by buying local utilities.

Storage, flexibility, trading

Eni, which, through its wholly-owned affiliate Stogit, owns and operates almost 98% of storage infrastructure in Italy, has been accused by the Italian regulator of not investing sufficiently in new underground storage facilities. Such investments are needed to ensure proper flexibility and security of supply for the Italian market, but also to enhance competition in a still uncompetitive market.

Storage capacity could be deemed insufficient – 13 bcm per year of working volume and 5 bcm dedicated to strategic storage, or a ratio to total demand of 15%, which is relatively low for the potential needs of the import-dependent Italian market. Insufficient storage capacity was a concern in 2007 for the regulatory authority who expressed fears of a potential winter shortage of available storage. This position encouraged the government to take emergency actions to optimise all supply and flexibility infrastructure usage.

The Italian trading hub, Punto di Scambio Virtuale (PSV), has seen limited activity despite significant potential with Russian, North Sea, Algerian, Libyan gas and LNG imported into Italy. In 2007, however, in order to encourage more trading, the Italian Government issued a decree by which royalites on domestic production are to be sold on the PSV via a public auction. The same decree also provides for newly authorised gas imports to be offered in part at the PSV. The lack of free pipeline capacity undermines any potential increase in trading, and PSV remains a small trading hub in terms of traded volumes (see European trading hub activity section).

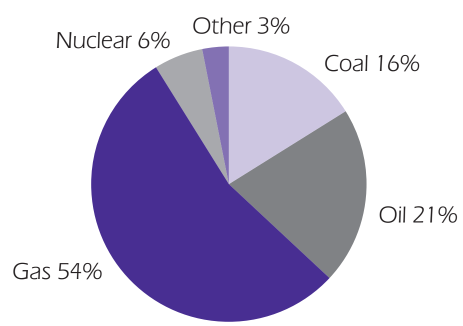
NON-OECD COUNTRIES AND PRODUCING REGIONS

Russia

This section outlines some of the major challenges facing the gas sector in Russia, as well as potential opportunities to be tapped.

As the world's largest holder of gas reserves, and the largest gas producer and exporter, developments in the Russian gas industry are pivotal to an understanding of the outlook for global gas markets. In particular, Gazprom, the giant Russian gas company, now one of the world's largest energy companies, plays a singular role in the Russian gas sector.

Figure 34 **Total primary energy supply in Russia (2005)**

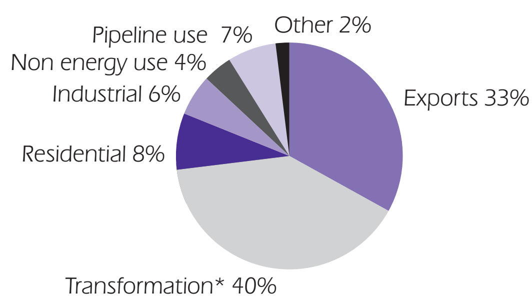


Source: IEA.

The Russian economy has continued its impressive growth by more than 6% per annum over the period 2006/07. Inflation, officially at 12%, is an issue with costs in the petroleum sector rising by more than 20-30% (in common with many other producing regions).

Gas is the dominant energy source, around 54% of TPES (2005), and accounts for more than half of the energy input into power generation (often associated with CHP). Total production in 2007 was 651 bcm, and total consumption 451 bcm. Continuing low domestic gas prices have slowed the planned shift from gas to coal and other sources of energy; the low price is also a disincentive to improved efficiency. National gas demand in 2006 grew by 11 bcm or around 3%, on the back of a very cold winter; a milder 2007 saw demand growth at a more modest 2%.

Figure 35 **Gas use in Russia (2006)**



Source: IEA.
Note: Transformation includes electricity and CHP.

Importance of Russia for global gas markets

Russia holds the largest share of global proven gas reserves; it is the world's largest natural gas producer and exporter and is the second largest natural gas consumer market after North America. OECD Europe imports almost a quarter of its current gas needs from Russia, either directly via Finland or Turkey, or via transit pipelines through Ukraine or Belarus. Over the outlook of this review, alternatives to Russian gas include pipeline gas from

North Africa and increasingly globalising LNG supplies. Through this interaction, Russian gas production and demand has the potential to affect other markets, such as the United States or Japan, indirectly through the increasingly global LNG market. Therefore, an appreciation of supply and demand fundamentals in Russia is critical to gaining an understanding of the future of gas markets worldwide.

One state-controlled company, OAO Gazprom, dominates the Russian gas sector, accounting for over 60% of Russian reserves (almost 30 tcm) and almost 85% of Russian production. Gazprom owns the Russian gas transmission system and has a legal monopoly on gas exports. Oil companies and independent gas producers each account for another 20% of Russian gas reserves and produce the balance of total production. Gazprom has recently acquired controlling interests in the major gas projects of Sakhalin-2 and Kovykta.

Central Asian supplies continue to be important in the overall picture of Russian gas supply and export. At the moment, Russian export pipelines are the dominant outlet for Turkmen and Kazakh gas supplies, except for Turkmen exports to Iran. Negotiations are continuing on the possibility of export to China. Further details of this are provided in the section on Central Asia.

There are significant opportunities to enhance Russian gas supply through improved pipelines operations, reducing leakage, and reduced flaring particularly through third-party access to the pipeline system. While benchmarking of electricity production efficiency is difficult because of the high heat use through CHP, it seems clear that there is very significant potential for reduced gas use in the sector, even as demand rises. Policy changes are critical to achieve these gains, including allowing domestic power and gas prices to rise – at least for industrial and large commercial users – and third party access to pipeline networks. Gas prices are planned to rise gradually, to Western European levels (net of transport and taxes) between 2008 and 2011 (although recent announcements suggest this timetable will slip to 2014) while electricity prices are slated to rise over the period to 2011. The latter will be central to the much needed investment in newly privatised utilities.

Russian gas reserves, investment and production plans

Russia clearly has sufficient reserves to back its ambitious supply plans; some 26% of global gas reserves (48 tcm) are located in the country, and there are undoubtedly more to be discovered. In early 2008, Gazprom reported reserve replacements in 2007 of 585 bcm, a reserve replacement ratio of 106% – the third year in a row it can boast having discovered more reserves than it produced. For the ten years before this, however, reserve replacement was in the order of 50-70%; the company producing much more than it was discovering. Times were difficult, with non-payments and low export prices – and even lower domestic prices. Despite this poor record, which has only recently turned around, the sufficiency of reserves in Russia is not an issue. However, the rate of investment to develop new fields, in more remote areas, including offshore, is pivotal, given declines in more mature areas.

Russian gas production is transforming from one based on existing production (for example Urengoi, Yamburg, and more recently Zapolyarnoye) to one increasingly dominated by production from new, more difficult-to-develop regions needing new transportation infrastructure. New production will be needed from Yamal in northern Siberia, Sakhalin II on the Pacific coast, and in the medium to longer-term Shtokman offshore in the Barents Sea. However, over the past 5 years Gazprom has focused on a major push to build alternative export pipeline routes, avoiding traditional transit countries and enhancing its control of major central and eastern European gas storage facilities and infrastructure. It is also active within Russia, in the process of acquiring controlling stakes in major coal companies, such as SUEK, and in various electricity companies as RAO UES has been restructured and privatised. Although such diversification will allow Gazprom to benefit from increasing domestic electricity prices and gain more control of various parts of the value chain down to domestic and foreign consumers, it raises the question of the timeliness and adequacy of capital spending in new upstream natural gas developments.

The IEA estimates, in year 2006 United States dollars, that about USD 18 billion per year of investment will be needed in Russia's gas sector (IEA, *WEO*, 2007) to ensure that sufficient gas is produced between now and 2030 for the domestic and export market. The majority of this investment is needed in production and pipeline assets. As the owner of the Russian pipeline system, developer of the Yamal region and co-coordinator of Eastern Siberian development, Gazprom will need to commit the vast majority of upstream and almost all pipeline investment. In this respect, Gazprom's investment programme for 2007 was of concern to the IEA. With an original investment program of USD 20.5 billion (upstream investment and pipeline expenditure (capex) of USD 14 billion and financial investments of USD 6.5 billion), Gazprom's board of directors revised the plan twice over 2007, increasing the financial investment figure upwards to USD 17 billion, leaving capex unchanged. This reflected Gazprom's priority over 2007:

- Acquiring existing natural gas production (Sakhalin-2, Kovykta);
- Positioning itself on the domestic market through acquisitions of coal companies and thermal generation companies in the RAO UES privatisation;
- Acquiring controlling interests in central and eastern European gas infrastructure and storage facilities.

At the end of 2007, the directors of Gazprom agreed that the investment budget for 2008 would be in the same order of magnitude as in 2007 at about USD 29 billion. The breakdown, however, reflected much more focus on capex than financial acquisitions with a split of USD 19.6 billion and USD 9.4 billion, respectively. For the first time, this exceeds the IEA's estimate of Russian gas sector investment needs – a reassuring sign that Gazprom may adequately focus on upstream development over 2008 – in the face of a number of major project start-ups in new, more difficult-to-develop, regions. However, given the cost inflation experienced globally in the oil and gas sector over the past few years – with prices for rigs and labour up 20% to as much as 50% in some cases – it is not clear if this increased focus on new capital spending will be adequate to compensate for higher costs. Recent Gazprom reports show sharp increases in operating costs, indicating that they are not immune to global cost trends.

Gazprom has commissioned new fields over the last 5 years to maintain production at around 550 bcm, counteracting the decline in production at key producing fields. This should be seen against the production decline at Gazprom's three long-standing mega producing fields (Yamburg, Urengoi and Medvezhye) over the same period of around 100 bcm. Of particular importance was the 2005 commissioning of Zapolyarnoye.

Figure 36 illustrates Gazprom's planned production profile to 2030 with a clear focus on the Yamal Peninsula starting up in 2011 and increasing in importance until it makes up more than 50% of Gazprom production in 2030. Until the start up of production at Yamal, the fields listed in table 32 below are to be commissioned. At the end of 2007, the Yuzhno Russkoye field was commissioned with a total of 26 wells drilled, producing at a daily rate of 15 million cubic metres. Production over the fourth quarter of 2007 was 1.4 bcm. It is expected to reach its maximum production of 25 bcm per year by 2009 plateauing for nine years based on 805 bcm of reserves. Work continues at the Kharvutinskaya field which is part of Gazprom's Yamburg complex. It is a priority field for Gazprom with an outlook to produce 18 bcm per year. In November 2007 unit 10 was brought on stream adding 8.2 bcm per year of production. In January 2008, unit 9 increased production by another 4 bcm per year.

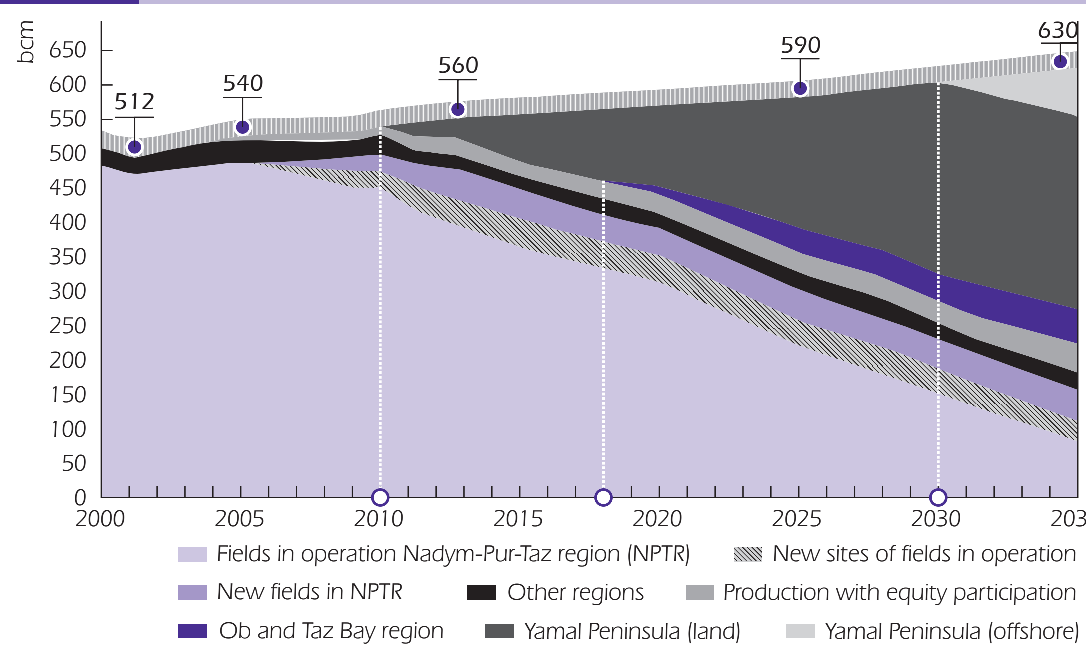
Table 32 illustrates how rapidly the new fields being or about to be commissioned reach their plateau and begin to decline – as opposed to the long period of sustained output that Gazprom has enjoyed with the three mega fields noted above over the past four decades. This reflects the maturity of the Nadym-Pur-Taz region and how production from new more expensive and difficult to develop regions is essential, if Russia is to maintain its role as a reliable supplier of natural gas to the domestic and export markets.

Gazprom's production to 2030 is increasing from current levels of 550 bcm in 2007 to 630 bcm in 2030. By 2015, less than 60% of Gazprom output will be based on existing production. The other 40% of production is expected to be split between tie in fields in Gazprom's existing producing region of Nadym-Pur-Taz, and Yamal. Thus more tie-in fields in existing producing regions will need to be commissioned in parallel with the opening up of the Yamal Peninsula with a staged approach to developing onshore fields (starting with the Bovanenskoye field). Figure 36 highlights the particular importance of timely development of the Yamal fields if Gazprom's ambitious production portfolio is to be maintained. Delays in production start up at any of these fields – especially at the Yamal fields – will translate into tight supply. This can be said of the production outlook of any oil and gas company. However, given Gazprom's outlook relying to a large extent on one key field in an extremely difficult to develop region on top of the fact that Gazprom produces the lion's share of natural gas in Russia and controls all transmission pipelines, delays in its production could have significant ripple effects across gas markets in Russia and globally.

By 2011, Yamal is expected to produce 15 bcm per year from the Bovanenskoye field with an outlook to grow to 115 bcm per year and a peak production of 140 bcm per year. Yamal has been described as an extremely difficult and challenging region in which to develop with permafrost making it difficult to stabilise infrastructure. The operational window is also very tight in terms of getting equipment to the construction site to ensure timely development. Furthermore, new warmer climate trends are affecting the construction plans, often requiring new project design, which needs to be tested and put in place. This is causing delays to the project timeline. Given these added difficulties and the sheer scale of the project, industry observers are concerned that the project will be commissioned on time.

The ambitious Shtokman project is based on a 3.7 tcm gas reserve located 600 km off shore in the Barents Sea. Development of the massive reserves faces significant technical challenges. In 2007, Total and StatoilHydro signed framework agreements to set up the Shtokman Development Company. Front-end enginerring and design (FEED) is

Figure 36 **Gazprom's production outlook to 2030 – Yamal is the key to Russian production post-2010**



Source: Gazprom.

Table 32 Outlook for new Russian gas fields commissioning over period 2007-2010

Field	Peak production (bcm per year)
Kharvutinskaya at Yamburgskoye	30 expected for 4 years
Yuzhno-Russkoye	25 expected for 9 years
Zapolyarnoye (neocom)	15 expected for 14 years
Achimovsky at Urengoiskoye	16 expected for 6 years
Zapadno-Pestsovaya	2 expected for 13 years
Yareiskaya at Yamsoveyskoye	0.5 expected for 18 years
Nydinskaya at Medvezhye	2 expected for 10 years
Severny Kupol at Gubinskoye	2 for 2 years
Total	**90 dropping to 50 after 6 years**

Source: Gazprom.

underway, based on landfall to Murmansk, and pipeline sales to Europe and LNG to the Atlantic region. Gazprom is targeting first gas output by 2013; most observers consider this an ambitious timeframe. (further details of the Shtokman project may be found in the LNG chapter).

Eastern Siberian developments

In spring 2006, 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 using eastern and western routes which would each supply 30-40 bcm. 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. Gazprom's President also said that the Kovykta field in the Irkutsk region of East Siberia could be a possible export source – but that gas from Sakhalin or West Siberia was still being considered. These political statements made in spring 2006 were very ambitious.

More recently, in June 2007, the Russian Minister of Industry and Energy, Viktor Khristenko, stated that Russia planned to export 68 bcm of gas per year to China by 2020 through two pipelines. During 2008 the Chinese National Petroleum Corporation (CNPC), China's biggest oil company, and Gazprom are to complete talks on the construction the pipelines. The western pipeline is expected to start pumping 30 bcm per year starting in 2011, and the eastern link to add 38 bcm per year by 2016. In July 2007, Transneft and

Gazprom set up a working group to discuss the construction of the gas pipeline along the ESPO (Eastern Siberian-Pacific Ocean) oil pipeline. The concept of a parallel natural gas pipeline is based on the structure of hydrocarbons in East Siberian deposits that are rich in associated gas and condensate.

Pipelines

The Russian pipeline system was built in the Soviet era on the basis of two sources of natural gas reserves – major fields of West Siberia and those of Central Asian states (Turkmenistan, Uzbekistan and Kazakhstan) which then made up part of the Soviet Union. In the past, some 50 bcm of Turkmen gas transited annually through the Gazprom system to supply Ukraine. Long-term contractual agreements discussed in 2003 for Russian imports of Turkmen gas (of up to 80 bcm per year from 2009-2029) affect this arrangement in terms of control and ownership of the gas. Turkmenistan has secured much higher prices for this gas recently (USD 180 per mcm); further details are provided in the Ukraine and Central Asian sections.

In 2006 Gazprom moved to what it calls market-based price setting principles for gas consumers in all CIS countries. As a result, in 2006 gas prices for the CIS region jumped two-to-threefold over night and are gradually reaching European levels. At present, there is a clear differentiation between contracts for gas supply to Ukraine and contracts for gas transit via its territory. For Belarus, the market principles are fixed in a five-year gas supply and transit contract.

Gazprom points to the transparency of relations with transit countries being beneficial to all parties and indispensable for securing the reliability of Russian gas deliveries to European consumers. The commercial dispute at the beginning of 2006 between Russia and Ukraine which cascaded briefly into Western markets caused many observers to question Russia's ongoing commitment to reliable supply. However, Russia's long history as a reliable supplier of gas to Europe suggests that it is Russia's intention to honour contractual commitments to trade partners in the IEA. Nevertheless, it is clear that more robust, transparent commercial terms are needed for many of these contracts if third party security is to be ensured.

Gazprom states that "special attention is paid to developing market-based cooperation with the major countries transiting Russian gas to Europe – Ukraine and Belarus". However, a key approach since difficulties arose with respect to transit has been Gazprom's strategy to build alternative export routes. This has led to the proposed Nord Stream pipeline from Russia to Germany via the Baltic seabed and the most recent negotiations over South Stream, to provide gas from Russia and the Caspian region under the Black Sea to Bulgaria and ultimately Italy (further details may be found in the Investment in new supply projects chapter).

Domestic market reforms

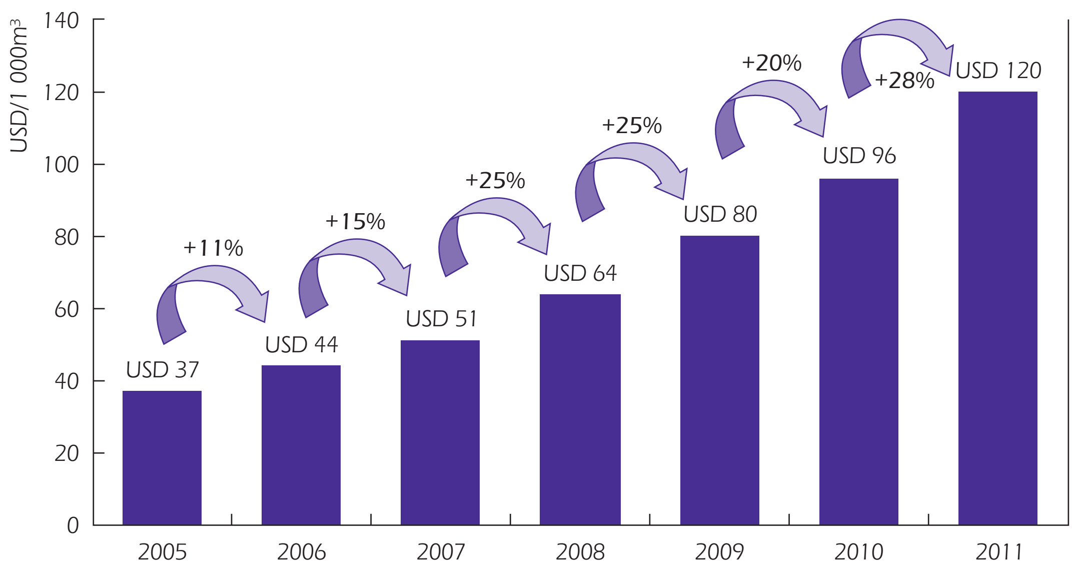
Independent gas producers

As noted above, independent gas producers and major Russian oil companies control a significant share of Russian natural gas reserves, but their share of total Russian output is somewhat lower. In 2006 independent gas producers transported about 115 bcm through the Gazprom trunk line system up from 92 bcm in 2001. Independent gas producers plan to increase gas production in Russia to 140-180 bcm per year by 2020. This is slightly more ambitious than the targets outlined in the 2003 Russian Energy Strategy with independent production accounting for 140-150 bcm per year in 2020. Lukoil alone has an outlook of increasing its natural gas and associated gas production from a level of under 15 bcm to over 70 bcm in 2016.[20] Although Rosneft does not specify a target gas output in its annual reports, the projects in which it is involved (Sakhalin-I and exploration at Sakhalin-III-IV-V and the Vankor field) "have considerable gas resources and are designed to play a key role in Rosneft's strategy to monetise its gas reserves".[21] Novatek, the largest independent gas producer in Russia, projects growth in its production to 45 bcm by 2010.[22]

Price reform

The policy approach is for price increases, so that by 2011 domestic prices will be at "parity" with export prices less transportation and excise duty. This would mean a domestic price which would be 60-

Figure 37 **Outlook for Russian domestic natural gas price increases**



Note: Arrow indicates price outlined in the Russian Energy Strategy.
Source: Gazprom, Financial-Economic Press conference by Gazprom, June 2007.

20. Presentation by Vagit Alekperov, President, LUKOIL, April 24, 2007, London, "Transforming into a Global Energy Company".
21. Rosneft , Annual Report, 2006.
22. Novatek, Annual Review, 2006.

70% of export prices. Progress has been steady over the past 2-3 years in meeting the plan for domestic price increases to more cost reflective levels. How much further this will move at the pace set out in figure 37 is not clear, as political and social impacts of these increases begin to be felt at the higher price levels in the context of a poor and generally deteriorating inflationary situation. Prices of course will be pivotal to improving energy efficiency, as well as providing better incentives for domestic production and sales, reduced flaring and losses in pipelines. One area of particular interest is the power sector. A true test of the government's will to keep to this ambitious timeline will be the price increase over 2008, scheduled to be 25%. As of June 2008, it seems likely that this strategy will be revised so parity is achieved not earlier than 2014-2015.

Russian power sector

Gross power output of 950 Twh makes Russia the fourth largest power producer globally. Gas dominates the Russian power sector, accounting for 46% of power output in 2005. Gas consumption in the power sector is the highest globally, at 260 bcm in 2006. Thus gas and electricity supply are closely linked in Russia.

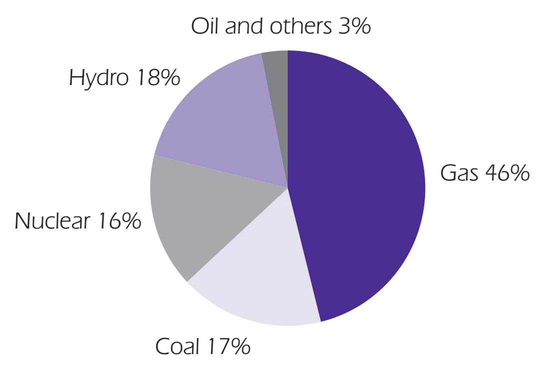
Russia has been involved in a near decade long process to reform its electricity sector.[23] 2008 marked an important point in this process, with the completion of the privatisation of the 20 major companies that were established from the break-up of monopoly UES of Russia. The reforms created six OGKs (wholesale thermal power generating companies, hydro and nuclear assets remain separate from this process), plus 14 territorial generating companies (TGKs), which provide district heating as well as power. Foreign companies have been strongly involved, including E.ON and RWE of Germany (OGK 4 and TGK 2 respectively), ENEL of Italy (OGK 5) and, Fortum of Finland (TGK 10 plus a minority share in TGK 1 around St Petersburg). Russian companies have also been active, including nickel and metals producer Norilsk, investment fund Onexim Group, but especially Gazprom and Russia's largest coal company SUEK. Gazprom obtained controlling or major stakes in OGK 2 and 6, and TGK 1 (St Petersburg), 3 (around Moscow), 12 and 13. The sales have generated revenues to the government of more than USD 30 billion to date. Purchasers of the new utilities are obliged to commit to significant capital spending accounting for around 30 GW of new generating capacity, plus extensive new transmission lines. At a capital cost of USD 1 000 per kW of capacity for new combined cycle gas turbines, or USD 2 000 per kW for new high efficiency coal plant, this will require USD 30-60 billion in new investment over the medium term.

Electricity prices, which are effectively controlled, are to be liberalised by 2011 for industrial users. Such liberalisation will be an important driver for new investment and improving efficiency, both in production and use of electricity. At roughly the same time, as noted earlier,

23. See *Russian Electricity Reform: Emerging challenges and opportunities*, IEA 2005.

government policy indicates that prices for gas used in Russia are also planned to rise, again driving important changes in gas production, and use, notably in electricity generation. It may no longer become the automatic fuel of choice for power, or at the very least, much higher conversion efficiencies would be encouraged. However, the Russian Government finds itself in a high inflation environment, and like many other governments, under pressure to preserve the purchasing power of its citizens. The pace and interaction of these two key regulatory reforms will thus be central to the evolution of the Russian energy sector over the next decade.

Figure 38 Electricity generation by power source in Russia (2005)



Source: IEA.

Assessing the size of possible savings is not straightforward. In particular, the widespread use of CHP based heat provision to communities makes benchmarking difficult. However, it seems clear that there is potential for significant gas and energy saving in the power sector. Much of the existing equipment is old, and with relatively low efficiency. New participants in the market could bring capital and expertise, especially with high efficiency CCGTs.

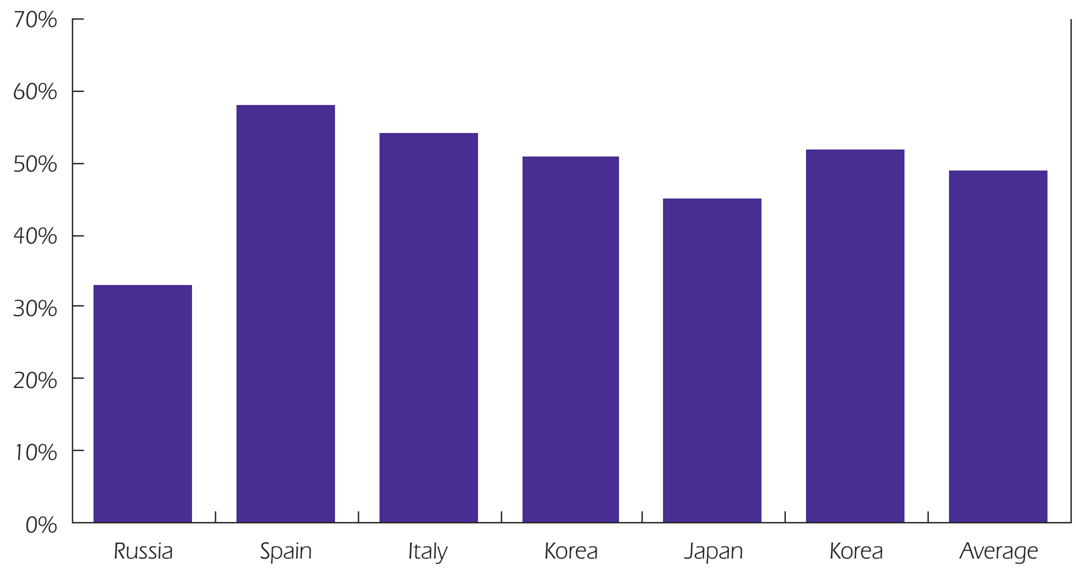
While a number of assumptions are required to perform these calculations, it seems clear that use of modern high efficiency CCGTs, coupled with improved CHP systems, has the potential to reduce the specific use of gas in power, to save at least 50 bcm and perhaps as much as 80 bcm in the power sector over the medium to longer term. In addition, greater penetration of coal (Russian reserves are considerable, by one estimate close to 100 billion tonnes) could free up gas supply to meet growing export demand, or offset declines from existing gas fields. Greater penetration of nuclear power or renewables could also achieve similar results (although with a significantly lesser greenhouse gas impact). This is in addition to the possibility for gas savings discussed in earlier IEA Gas Market Reviews from, for example, reduced gas flaring, and greater efficiency in pipeline operations.

Concluding remarks

Russia's gas sector is at a major turning point. Given its key importance to global gas markets, its actions – as well as how it is perceived to be acting – affect consumer confidence and decision making. It is for this reason the IEA pays particular attention to Russia and Gazprom and repeats its calls for greater transparency in the sector, particularly with regard to investment in future production. Key factors include:

- Russia's gas production in the future will increasingly depend on fields in

Figure 39 **Efficiency of heat & power production from gas in Russia (2005)**



Source: IEA.

much more difficult-to-develop and environmentally sensitive regions and increasingly less on fields upon which Gazprom has almost exclusively depended for the last four decades. Consumers are interested in more transparency and information on development drilling and investments in these new gas regions.

- Russia's long standing close relations with Central Asian countries are shifting as the latter seek more control over their natural resources and export markets. Investors are interested in these newly opening countries and providing access to markets to support economic development while enhancing energy security. China is of course one such investor.

- Reform in electricity and gas prices is the key to energy efficiency in Russia and this could be a more economic way to balance gas demand and supply by improving the efficiency with which gas is used in Russia.

Ukraine

Market overview

Ukraine is important for European and global gas markets because it is a key transit country and a major gas consumer. In 2007, it transited over 115 bcm of Russian gas to Europe and used domestically about 70 bcm,[24] of which over 50 bcm were imported through or from Russia. Given

24. Including final consumption, losses and own use by the gas industry. Source: Weekly Monitoring "Energobiznes".

that Ukraine's gas import and transit arrangements are closely intertwined, the situation on the Ukrainian domestic gas market and the country's trade relations with Russia have the potential to have serious implications for consumers in Western Europe. For example, a price dispute between Russia and Ukraine in January 2006 resulted in a brief supply disruption in several European countries.

The Ukrainian gas market has changed significantly over the last years. Following the sharp price increases for gas imports from USD 50 per per 1 000 m^3 in 2005 to USD 95 in 2006, to USD 130 in 2007 and USD 179.5 in 2008,[25] Ukraine's domestic gas use dropped from 80.4 bcm in 2005 to an estimated 69.8 bcm in 2007. The Ukrainian economy coped with gas price increases quite well: the country's GDP grew by over 7% in 2006 and 2007. Nevertheless, growing gas prices have contributed to the general high inflation rate: consumer prices have risen by 16.7% in 2007, compared to 11.6% in 2006, and continued to grow at an even higher rate in the first quarter of 2008.[26] On the positive side, growing gas prices have provided a strong stimulus for the Ukrainian economy to become less energy-intensive. Gas-intensive industry has seen major energy efficiency improvements. However, gas tariffs for households and district heating companies remain subsidised, which adversely affects efficiency improvements.[27]

Non-payment remains a problem. The average collection rate was about 87% in 2007, but reportedly dropped to as low as 35% at the beginning of 2008, according to President Yushchenko's statement at the time of Ukraine's dispute with Russia over accumulated debt for gas imports. District heating companies, in particular, have the poorest payment discipline. Low regulated tariffs and non-payment add to financial problems of the national oil and gas company Naftogaz of Ukraine, which has difficulties in meeting its loan obligations. The company's government-approved financial plan for 2008 foresees UAH (Ukraine Hryvnia) 8.043 billion (USD 1.64 billion) in direct subsidies from the state budget to avoid Naftogaz's bankruptcy.

Following Yulia Tymoshenko's appointment as Prime Minister in December 2007, the Ukrainian government has struggled to abolish gas supply intermediaries – RosUkrEnergo (a Swiss-registered company half-owned by Gazprom, the other half belonging to two Ukrainian businessmen) and UkrGasEnergo (a joint venture between RosUkrEnergo and Naftogaz of Ukraine). RosUkrEnergo imported Central Asian and Russian gas to Ukraine in 2006-07, similarly to the previous middlemen companies – Itera and EuralTransGas. All these intermediaries did not own or operate the pipelines that transported the gas, but

25. The latest price increase for Ukraine corresponds to the increase in the price that Gazprom agreed to pay for Turkmen gas in 2008. On the other hand, the fee for transiting Russian gas through Ukraine has also grown slightly in 2008: from USD1.6 to USD 1.7/ 1 000 m^3/ 100 km.

26. Source: website of the State Statistics Committee of Ukraine accessed on 13 May 2008.

27. In 2007 and early 2008, gas tariffs for households varied from UAH (Ukraine Hryvnia) 0.32 to UAH 1.29 per 1m3 depending on total gas consumption volume and the presence or absence of gas meters. Source: National Electricity Regulatory Commission www.nerc.gov.ua.

Box 2 **The Russia-Ukraine dispute**

The geopolitical tensions over Russia-Ukraine and Russia-Belarus disputes in 2006-07, in a context of import price rises, fed growing concerns over a potential renewed gas crisis involving Russian gas and its transit to Europe. In February 2008, such prospects loomed as Russia and Ukraine could not agree on prices, contracts and responsibilities on gas supplies and transit, in addition to tensions over Ukraine's outstanding debt for gas imports. On 3 March, Gazprom reduced supplies to Ukraine initially by 25% or 40 million cubic metres a day. A further cut was implemented the following morning, taking the total reduction to 50%. Ukraine hinted at that time that it would cut flows of Russian gas to Europe through its pipelines if it ran short of supplies. Instead, it drew upon its substantial storage reserves to meet domestic demand so gas flow to Europe was not interrupted. Full delivery of gas to Ukraine resumed shortly after Naftogaz of Ukraine and Gazprom reached apparent agreement. However, for the future, these matters remain far from settled. Pressure to raise prices towards the western-European level (currently around USD 400 per 1 000 m^3) can be expected to continue through 2008 and into 2009. Current Ukrainian prices are USD 180 per 1 000 m^3, more than triple those of 2005.

The IEA paid close attention to the dispute as it evolved. The IEA position on the matter was clear: the IEA encourages disputing parties to settle such agreements in a normal commercial manner, via arbitration or formal dispute settlement procedures. Third-party users should not be affected by commercial disputes between Russia and its transit partners. Russia has been an extremely reliable gas supplier to Europe over nearly four decades, with the notable exception of a two-day interruption at the beginning of 2006, related to an earlier phase of this ongoing dispute. Another interruption to western consumers would severely tarnish Russia's reputation as a reliable supplier. To address similar disputes, gas supply and transit arrangements should be made as transparent as possible, especially if intermediaries are involved. Continuing dialogue between all the affected parties is certainly to be encouraged.

dealt with paperwork related to gas trade, receiving very lucrative compensation for these services. In 2006-07, RosUkrEnergo sold the imported gas to UkrGasEnergo at the Ukrainian border, and the latter sold it to Ukrainian final consumers. While UkrGasEnergo supplied gas to the most lucrative industrial consumers, Naftogaz of Ukraine had the obligation to supply gas to households, public institutions and district heating companies at low regulated prices, which exacerbated the company's financial difficulties. The prospect of Naftogaz's possible bankruptcy raised concerns in Ukraine about the future of the country's gas transportation system, considered a strategic national asset and currently operated by Naftogaz of Ukraine's affiliate.

On 12 March 2008, Naftogaz of Ukraine and Gazprom signed an agreement, which ended UkrGasEnergo participation in the Ukrainian market. From April 2008, RosUkrEnergo is supposed to sell gas directly to Naftogaz of Ukraine at the Ukrainian border at USD 179.5 per 1 000 m^3. Naftogaz of Ukraine will then supply gas to final consumers, including industrial companies. However, the 12 March deal introduces a new intermediary – Gazprom's subsidiary Gazpromsbyt-Ukraine, which will buy up to 7.5 bcm per year from Naftogaz of Ukraine to sell further on the Ukrainian market. As of mid-2008, the exact details of gas supply mechanisms to Ukraine in 2008 and the following years remain unresolved.

Facing growing gas import prices, one of Ukraine's declared priorities is the development of domestic hydrocarbon resources.[28] However, the progress in this area has been slow. By law, natural gas produced in Ukraine must be sold to domestic consumers at low regulated prices. This policy, as well as an unfavourable licensing regime, deters investment in hydrocarbon exploration and production. Ukraine's first production-sharing agreement (PSA) with United States-based exploration company, Vanco Energy, for the rights to develop the Prikerchensky block in the Black Sea, was under threat of cancellation in May 2008 barely six months after its signature in October 2007.

Gas storage

Ukraine has significant gas storage capacity at 13 facilities, which can contain up to 36 bcm (including a 2.65 bcm capacity addition in progress) of working gas. Ukrtransgaz operates 12 of the underground gas storage facilities (ten in depleted gas fields and two in aquifers); Chornomornaftogaz operates another facility in Crimea.[29] At present, just over half of this capacity is used. Ukrtransgaz and Chornomornaftogaz inject some 15-18 bcm of gas into storage every summer and withdraw it in winter, when demand is at its peak. In 2007, for example, they injected 18 bcm and withdrew 13.5 bcm of gas. When the storage facilities are full, it is possible to withdraw up to 250 mcm per day. Ukraine's official Energy Strategy to 2030 states that the gas storage capacity can be increased by 7 bcm per year by reconstructing and modernising three storage facilities: Solokhivske, Proletarske and Bilche-Volynsko-Uherske.

The storage facilities situated in western Ukraine are used almost exclusively for servicing export; the one in Crimea is used only for servicing markets in the peninsula. Therefore Ukraine cannot use much of its vacant storage capacity for the domestic market. Naftogaz of Ukraine has been trying to sell its storage services to customers in western Europe, but with little success. On several occasions, Gazprom has indicated its interest in acquiring equity in underground gas storage facilities, but Naftogaz of Ukraine has declined. Gazprom previously stored some gas in Ukraine, which was intended for export to Europe. According to the National Gas Union of Ukraine, Gazprom injected, stored and withdrew nearly 73 bcm of gas to and from the Ukrainian storage facilities between 1993 and 2005,[30]

28. Ukraine currently produces about 20 bcm of gas and 4 million tonnes of oil per year.
29. Both Ukrtransgaz and Chornomornaftogaz are affiliates of the national oil and gas company Naftogaz of Ukraine.
30. National Gas Union, 2006.

equal to an annual average of about 6 bcm. However, from 2006 Gazprom reportedly does not have any gas in Ukrainian storage facilities. According to publicly available data, the 13.5 bcm withdrawn from Ukrainian storage facilities in 2007 included 1.9 bcm belonging to Naftogaz of Ukraine, 5.6 bcm to RosUkrEnergo, 2.3 bcm to UkrGaz-Energo and the rest to Chornomornaftogaz and other owners.[31]

Caspian region

The Caspian region includes a major exporter of gas (Turkmenistan) with ambitious plans to increase production and export, a second major producer (Uzbekistan) whose output is primarily dedicated to meeting domestic demand, and two other countries (Azerbaijan and Kazakhstan) that are just emerging as net exporters. The contribution of the Caspian region to global gas supply will depend on the level of investment in exploration and production, and on the availability of reliable routes to international market on commercial terms. Volumes available for export will also depend on the region's own demand for gas; energy use across the region is very inefficient, and gas demand has been rising steadily on the back of subsidised prices for domestic consumers.

With the exception of a relatively small-capacity pipeline from Turkmenistan to Iran, current routes to international market for east Caspian producers are through the Russian pipeline network. The prices offered by Russia for Central Asian gas exports (from Turkmenistan, Kazakhstan and Uzbekistan) have risen significantly in 2007-2008, and are set to rise further. From a figure of USD 100 per 1 000 m^3 in 2007, Russia agreed to pay USD 130 per 1 000 m^3 in the first half of 2008 for Turkmenistan exports (which make up the bulk of the Central Asian gas trade) and USD 150 per 1 000 m^3 in the second half of the year. Prices for export from other Central Asian gas producers have followed a similar trajectory. In March 2008, Gazprom and the heads of the national oil and gas companies from Turkmenistan, Kazakhstan and Uzbekistan announced that trade in Central Asian gas would, from 2009, take place at 'European-level prices'; this would imply a parity with the price paid on the European market for Russian natural gas, minus the costs of transportation and taxes back to the relevant delivery point in Central Asia.

Russia's readiness to transmit higher international prices to Central Asian producers is significant for three reasons. Firstly, it highlights Russia's acute need for Central Asian gas to make up its own gas balance. Secondly, it reflects Russia's determination to maintain its strong relationships with gas producers in the region in the face of increased competition, notably from China but also from potential new markets in Southern Asia and across the Caspian Sea towards Europe. Thirdly, it has implications for Ukraine; as a major current importer of east Caspian gas, Ukraine can expect to see higher prices coming though in future negotiations on gas supply.

31. Weekly Monitoring "Energobiznes", 2008.

On the western side of the Caspian, the start of production from the offshore Shah Deniz field marked the arrival of Azerbaijan as a net gas exporter. Deliveries began in 2007 through the Baku-Tbilisi-Erzurum pipeline to Georgia and to Turkey, although initial volumes were small (1.2 bcm supplied to Turkey in 2007). Of the three countries of the South Caucasus, as of 2008 only Armenia remains an importer of Russian gas.

Turkmenistan

Turkmenistan is the region's largest producer, with output of 72.3 bcm in 2007. Domestic consumption of around 18 bcm in 2007 is high on a per capita basis, which is unsurprising given that natural gas is provided free of charge to residential consumers and is subsidised for industrial use. Nonetheless, the relatively small population (6.7 million) means that large volumes are still available for export.

In line with a long-term agreement signed in 2003, Russia is the main importer of Turkmen gas. If sufficient gas is available, current exports of around 50 bcm per year are scheduled to increase to 80 bcm per year from 2009. Exports along Turkmenistan's other current export route, to Iran, were interrupted in December 2007 with gas supply being strained by a dispute over pricing and also by exceptionally cold weather.

Estimates of Turkmenistan's natural gas reserves vary considerably, introducing a large element of uncertainty into projections of its future contribution to global gas supply. Official sources have put gas reserves in the country at more than 20 tcm, an amount approaching the range of proven reserves in Iran or Qatar – and far more than the 2.9 tcm estimated by BP in its statistical review (2007). The government announced in April 2008 an international audit of Turkmenistan's gas reserves.

Clarity over reserves, and over the conditions for investment, will be crucial in determining the path for gas supply developments in Turkmenistan and in buttressing the credibility of the government's intentions to raise production to 250 bcm per year by 2030. Current gas production in Turkmenistan is primarily from onshore and mature fields that were initially developed in the Soviet period. Major investment is required in order to compensate for declining output from existing fields and to develop new reserves. The government has stated that it welcomes foreign investment in offshore Caspian reserves (which are assumed to be predominantly oil), as well as assistance on a contractual basis to state-owned Turkmenneftegaz in developing onshore deposits. Investment in the upstream will determine Turkmenistan's ability to support multiple export routes.

Petronas Carigali, a subsidiary of Petronas, is engaged in exploration and production activities in Turkmenistan, and is currently building facilities, including a gas-processing plant, to enable delivery of gas from its Caspian Sea oil and gas fields. The facilities are expected to be operational by the end of March 2010 and will have an initial capacity of 5 bcm increasing to 10 bcm per year within three years of operations.

In July 2007, Turkmenistan and CNPC signed a PSA for development of gas reserves on the right bank of the Amy Darya River in eastern Turkmenistan. At the same time, China signed a gas supply contract for 30 bcm per year for 30 years with deliveries provisionally scheduled to start at the end of 2009, and work has started on a new export pipeline from eastern Turkmenistan through Uzbekistan and Kazakhstan to the western Chinese border. Turkmenistan has also been supporting other possible diversification options, such as a pipeline across Afghanistan to Pakistan and India, and options for gas trade with Europe (see Investment in new supply projects chapter).

Uzbekistan

Uzbekistan is a major gas producer, with production of 65.3 bcm in 2007, but a relatively minor exporter (14.7 bcm) since the bulk of production is dedicated to the domestic market. Uzbekistan is the most populous of the former Soviet Central Asian republics (population of 26.7 million, 2006); domestic natural gas prices have remained low, and energy use, as elsewhere in Central Asia, is inefficient.

Following signs of a slowdown in oil and gas output in 2005, Uzbekistan has sought to increase investment in exploration and production, and has concluded a number of new PSAs predominantly with Russian and Asian companies. As of 2008, Russia's Gazprom, Soyuzneftegaz and Lukoil, Malaysia's Petronas, China's CNPC, and Korean KNOC were the main companies operating in Uzbekistan, often in partnership with state-owned Uzbekneftegaz.

The majority of gas exports, 10.5 bcm out of 14.7 bcm total exports in 2007, went to Russia – with the remainder going to Uzbekistan's neighbours in Central Asia. Exports are expected to rise to 16 bcm in 2008. While Russia is likely to remain the most significant export market, the construction of a gas pipeline to China from Turkmenistan through Uzbekistan (and Kazakhstan) to China will open up the possibility of gas trade with China.

Kazakhstan

Almost all of the gas produced in Kazakhstan is associated with oil production, notably from the Tengiz and Karachaganak projects in the west of the country. Much of this gas is re-injected in order to maintain reservoir pressure and enhance oil output; gas flaring has also been prevalent, although this has decreased since 2005 as a result of government regulation.

Production of 'marketable gas' was only 12.9 bcm in 2007, against consumption of 13.3 bcm. The main consumers of natural gas in southern Kazakhstan are distant from the production areas and are supplied primarily by imports from Uzbekistan; around 7 bcm per year is currently exported north to Russia, mainly from the Karachaganak field to the Orenburg gas processing plant across the border. Kazakhstan has looked to reduce its dependence on (occasionally erratic) imports by developing gas fields closer to the main population areas. Official estimates are that the volume of 'marketable gas' will increase to around 30 bcm by 2020, against anticipated gas demand of 18.7 bcm.

Azerbaijan

The main sources of gas in Azerbaijan are all offshore, and include fields operated by SOCAR (the national oil and gas company), associated gas from the Azeri-Chirag-Guneshli oil field that is operated by the Azerbaijan International Oil Company (AIOC) and – from December 2006 – the start of production from the major Shah Deniz gas and condensate field. The Shah Deniz field is being developed by a consortium that includes BP as operator, and represents much of Azerbaijan's export potential in the short term. The main gas export route is the South Caucasus Pipeline, completed in 2006, which leads from Baku through Tbilisi to join with the Turkish gas grid in Erzurum. Phase I of Shah Deniz output, which is scheduled to reach a plateau of 8.6 bcm per year, is being sold to Azerbaijan, Georgia and to Turkey. Actual gas production from Shah Deniz in 2007 was 3.1 bcm, and this is expected to rise to 7.7 bcm in 2008. The price of gas sold to Turkey was capped at USD 120 per 1 000 m^3 until April 2008.

Azerbaijan has substantial additional potential for gas production from Shah Deniz: Phase II development, that was confirmed in 2007, is scheduled to bring additional gas to market from 2013 (with volumes at least as large as Phase I, and possibly around 12-15 bcm per year); the consortium also announced in 2007 the discovery, beneath the currently producing structure, of a deep high pressure reservoir whose potential is now being assessed. Alongside Shah Deniz, there is the possibility of additional production from SOCAR fields as well as other deep offshore reservoirs. However, the timing, volumes, transit arrangements and marketing of gas supply after Phase I of Shah Deniz remain to be determined.

Middle East and North Africa

Pressures on Middle East gas supplies have increased over the last year, with production proving inadequate to meet the multiple calls on the region's gas, while investment and price structures have still to be refined sufficiently to incentivise future growth on the scale necessary. With 45% of the world's reserves – and around 17% of supply in 2006, the region still has considerable potential as a growth area. However, there remains a disjoint in the timing required to match resources to internal, regional and overseas markets in the interim which is likely to extend well into the next decade.

Slow upstream development relative to rapidly expanding natural gas usage in oilfield re-injection, power generation, petrochemicals as well as export allocations is at the heart of the issue. Iran and Egypt have been particularly affected – resulting in periodic shortfalls in the gas available for domestic users and in some cases, exports. The symptoms of this include increasingly frequent blackouts and brownouts at times of peak summer demand. In Iran and the United Arab Emirates (UAE), periodic reductions in gas flows for oilfield re-injection have been reported. Oman, Iran and Egypt, have taken steps to limit gas allocations to export projects at times of peak domestic demand. Qatar and Egypt have both called moratoria on new gas export projects until the end of the decade. At the same time, a number of would-be regional gas importers have emerged, among them Bahrain, Israel, Kuwait, Oman, Syria and the UAE - with the list of potential local suppliers limited to Iran – and to a lesser extent Qatar, Egypt and Libya, at least for the medium-term.

Increasingly, the lack of near-term gas availability for regional use is compelling users to substitute gas with crude oil or oil products - with implications for those markets. This represents an about-turn from a previous policy to 'switch to gas' in most Middle Eastern states. Of note, Saudi Arabia has decided that coastal power plants will be run on liquid fuel, while the region's largest refining project at al-Zour in Kuwait, is viewed as a source of feedstock for domestic power generation, with around 45% of its 615000 b/d earmarked for domestic use. In the longer-term, a number of countries are also looking at non-hydrocarbon alternatives, including nuclear energy and renewables, to meet the domestic demand call.

Table 33 **Gas snapshot of key MENA reserve holders**

Country	Reserves (bcm)	Production 2007 (bcm)	Gas production targets	Export plans to 2012	Investment terms
Algeria	4 580	90 (sales)	110 bcm (2011)	2 Pipelines, 2 LNG projects. Exports of 85 bcm by 2012 and 100 bcm by 2015.	PSA – licensing rounds
Egypt	1 965	58	62 bcm (2015)	1 x LNG expansion, some contracted increase in volumes through Arab and Israeli gas pipelines.	PSA – licensing rounds
Iraq	3 170	6	18 bcm (2013)	Akkas field link into Syria - and potentially into the Arab gas pipeline. Floating LNG from Southern gas flaring.	TSA under consideration. PSA In Kurdish areas
Iran	28 130	168	270 bcm (2012)	3 x LNG projects, 2 x short-distance pipelines, expansion of Turkey pipeline sales, 1 x long-distance pipeline.	Enhanced TSA (buyback) – licensing rounds and bilateral negotiations
Kuwait	1 780	11	18 bcm (2012)	None	Enhanced TSA under consideration
Qatar	25 783	83	238 bcm (2012)	64 bcm per year additional LNG by 2011.	PSA – integrated projects more usual
Libya	1 491	27	34 bcm (2010)	Pipeline expansion and LNG upgrade. New LNG facilities depending on supply.	PSA - licensing rounds and bilateral negotiations
Saudi Arabia	7 070	71 (sales)	99 bcm (2012)	None	PSA - one licensing round to date.
UAE	6 061	49	74 bcm (2009)	None	Concession – licensing round on field by field basis.

Source: IEA.
Note: PSA (production sharing agreement); TSA (technical service agreement).
Some production targets may represent wellhead production, potentially including associated condensate and other heavier hydrocarbon production.

Despite the apparent financial attractions of developing gas for international markets at current price levels, concern about the domestic energy balance is a key factor holding back approval for new export projects in a number of countries, which is likely to lead to a hiatus in regional supply growth after the current wave of projects under development are completed. Without a reduction in domestic demand growth, which is being fuelled by strong economic growth and subsidised prices, or a significant increase in upstream project delivery, gas export availability is likely to remain constrained well into the next decade. At the present time, only Libya and Iran are committed to making substantial new contributions to the international market in that period and Iran's record to date argues against too much emphasis on its role.

Nevertheless, the current project load will lead to a sharp expansion in MENA gas supplies from 2008-13, most notably in Qatar and Algeria. Libya, Yemen and Egypt are also set to contribute more modest gas export volumes in this timeframe. Despite its reserve base, Iran remains a wildcard, with a number of export initiatives, including regional and long-distance pipelines as well as LNG projects under discussion for the 2013 timeframe, but only minimal progress made in terms of project awards.

Algeria

Algeria, along with Qatar, is one of the main growth areas in the period to 2013, with an eye to exports as well as domestic users. State-owned Sonatrach has targeted gas exports of 85 bcm by 2012 rising to 100 bcm in 2015. Within this, Sonatrach is undertaking two LNG projects and working with foreign partners on the development of 23 bcm of new pipeline capacity, including new pipelines to Italy (Galsi for 2012) and Spain (Medgaz for 2009) to complement the existing Transmed pipeline to Italy and the Pedro Duran Farrel to Spain via Morocco. Gas reserves in the Berkine basin, as well as more difficult reserves from the southwest of the country are expected to feed these projects. These will require significant further infrastructure investments around Hassi R'Mel. Further supplies are envisaged from recent exploration successes, which included 20 oil and gas discoveries in 2007. Algeria has also resumed licensing rounds for upstream acreage in 2008, after a hiatus caused by revisions to the Hydrocarbon Law in 2005 and 2006. Sonatrach is now exporting a total about 62 bcm a year in the form of both LNG and pipeline gas.

The cancellation of the Gassi Touil integrated-gas project with the Spanish Repsol-Gas Natural consortium in 2007 has seen Sonatrach take on a further LNG project alone (in addition to the Skikda replacement train). Sonatrach claims that the Gassi Touil contract was withdrawn from the consortium as a result of non-performance. The Spanish consortium had hoped to have the chance to renegotiate aspects of the contract in the light of rising service and materials costs, which surged after the initial contract award in 2004. The issue is now the subject of international arbitration, but Sonatrach has continued construction of the plant with the support of service companies. Start-up at Gassi Touil is planned for 2012, from an initial date of 2009, with Skikda due online in 2011.

New power generation projects, a large programme of seawater desalination plants, and the renewed promotion of petrochemicals and gas-based industry will see an increase in Algerian domestic consumption from current levels of around 26 bcm. However, the size of the resource base and ongoing exploration success, mean that the tension is not as great as in other parts of the region. In addition, Algeria has continued negotiations with Nigeria and potential European buyers over the Trans-Saharan Gas Pipeline (TSGP) which would feed Nigerian gas to Europe via Algeria from around 2015, and potentially provide some additional gas for Algerian use in case of requirement.

Libya

In Libya, the emphasis also remains on export markets, with domestic consumption expected to increase rapidly, albeit from a small base due to the limited population size and a small industrial base. Following Shell's integrated gas deal of 2004, which could lead to a new LNG project in the case of sufficient reserves, BP has also signed up for exploration prospects in the offshore Sirte and onshore Ghadames basin, with a view to locating feedgas for an LNG facility. ExxonMobil is also actively searching for potentially exportable gas in the offshore area. At end-2007, the only existing gas exporter, Eni, committed to a 10-year deal which includes the further development of its gas fields to supply an additional 3 bcm of gas through the 8 bcm Greenstream pipeline to Italy and a new 5 bcm per year LNG facility. The LNG deals are unlikely to yield significant gas exports before 2013, but they put Libya in play to be one of the few regional players to make a definite contribution to export growth in the latter half of the next decade. The country also held its first upstream licensing round focusing specifically on gas in 2007, with a view to more than doubling its existing proven reserve base of 1.5 tcm.

Egypt

Egypt is facing a more challenging balancing act between domestic gas use and exports than its North African neighbours, with exports formally restricted to a third of the reserve base in order to ensure adequate supplies for future generations. In 2007, the SEGAS project at Damietta was reported to have run at 4.9 bcm, below its capacity of 6.5 bcm per year. There were some reports that this reflected strong domestic demand from the power sector, residential buyers and industry, although it was also reported that Egypt was seeking a higher feedgas price and a greater stake in any further trains. Two new export outlets were opened up in early 2008, in the form of a pipeline to Israel and the extension of the Arab gas pipeline from Egypt through Jordan into Syria. That pipeline will be linked into the Turkish grid in the next phase of development, although there will be limited gas for onwards delivery for the near-term. Indeed, pipeline exports are the main target of a temporary 'moratorium' called on Egypt's gas sales in 2008, which will affect the government share of gas projects. The decision followed months of public controversy over Egyptian gas sales prices amidst concern about long-term domestic availability. Officials have clarified that this won't affect the timetable for a second train at the Damietta LNG on which a final investment decision is now due in 2008, having been put back from late 2007.

Despite near-term availability concerns, efforts to increase the reserve base through regular licensing rounds and increased exploration are having a positive impact. In early 2008, BP announced a find at the Satis field in one of its Nile Delta concessions of around 28 bcm, following a similar-scale success in Mediterranean acreage in 2007. Meanwhile, the Egyptian government came to an agreement with offshore gas developers to raise purchase prices in order to provide a greater commercial case for offshore developments for the domestic market (see price discussion below).

Syria

While Syria is unlikely to ever become a net exporter of gas, it expects modest production increases in the next five years from projects around the Palmyra area which will increase sales gas capacity to 10.1 bcm from around 4.4 bcm in 2007. In addition, Syria has some potential as a transit state with the Egyptian-fed Arab gas pipeline arriving at Homs in July 2008, which will eventually reach Turkish, European and Lebanese markets, although gas volumes are likely to be very limited in the near-term. Syria also signed a memorandum of understanding with Iraq in 2007 for gas transit from the border field of Akkas which could be used domestically or linked into the Arab gas network. Syria has also contracted for 2-3 bcm of Iranian supplies from 2009 through a spur off the existing Iran-Turkey pipeline.

Iraq

Iraq's long-term potential as a major gas producer and exporter remains strong, with proven reserves of some 3.2 tcm and plenty of untapped exploration potential. However, the legal and operational climate requires significant improvements for anything but one-off development awards to move forward. In this light, a handful of projects have been discussed, including the development of the Akkas field on the Syrian border under a technical service contract with potential to produce around 5 bcm of gas in the first instance.

After the completion of a master gas plan by Shell, Iraq is also looking at the near-term development of the Mansuriya field, again with a view to exports. Some of the easiest available gas for Iraq would be the 8 bcm plus of associated gas which is flared each year from the country's oilfields. With plans to increase oil production to up to 3.5 million b/d in the medium-term from today's level of around 2.4 million b/d, this problem will worsen unless processing facilities are rehabilitated or put in place. A floating LNG facility in the Gulf is one of the plans currently on the table for associated gas from the Rumeila fields. In the Kurdistan area, the priority is also on gas development for domestic power generation. As such, Dana Gas is developing the Khor Mor with the intention of producing up to 1.6 bcm per year from mid-2008 (6 months behind schedule) with a target of 3.1 bcm in 2009. It is also carrying out appraisal at the working on the Chemchemal field, again with power generation needs in mind.

Gulf Region

It is in the Gulf region that the greatest tensions are being felt between strong demand and limited new supplies. The lack of infrastructure to feedgas from reserve-rich places to more constrained neighbours is a key factor, despite the start-up of the regional Dolphin pipeline in 2007 feeding Qatari gas to the United Arab Emirates and to Oman (from late 2008). Offshore pipelines between other states have been held back by political disputes. In the absence of approval from Saudi Arabia for a pipeline link between Qatar and Kuwait, the latter is now putting in place plans for an LNG regasification terminal to operate from 2009 as a stop-gap to meet its demand from power generation and desalination in particular. Dubai is also planning a regasification facility to supplement Dolphin gas. Meanwhile, a number of regional states are considering nuclear power as an alternative to hydrocarbons, in addition to renewables.

Qatar

Qatar remains the region's major gas surplus state and its leading performer in terms of new gas development. It is undertaking plans with foreign partners for the expansion of LNG export capacity to 105 bcm per year by 2011, from 2007 levels of 40 bcm, based on a proven resource base of over 25 tcm. Plans include the development of the world's largest trains of 10.6 bcm per year in the Qatargas and Rasgas ventures, in addition to the largest gas-to-liquids plant at the Shell/Qatar Petroleum Pearl project. However, Qatar has not been immune from problems of cost escalation, most notably through difficulties in accessing materials and services in a timely fashion. This has contributed to a six-month plus delay in the commissioning of the first train at Qatargas II and the postponement of Rasgas III to early 2009. Project participants believe that this will have a knock-on effect through the project chain.

Meanwhile, the country's contribution to new gas deliveries beyond 2012 remains unclear due to the moratorium on new export projects imposed in 2005 to study the effect of the existing project load on North Field reservoirs. Rather than look to further exports – in the form of LNG, GTL or pipeline gas, there are indications that the country will seek to increase its resource base through further exploration, potentially targeting new North Field reservoir depths, before evaluating next steps. In addition, it is also concerned that domestic users, including a burgeoning petrochemical sector, receive adequate gas. In 2007, gas blocks at the North Field assigned to the cancelled Exxon GTL projects were reassigned to the domestic Barzan project in a sign that even the region's most significant gas player has a domestic constituency to satisfy.

United Arab Emirates (UAE)

Surging energy demand from industrial projects, power generation and desalination has led to particular stresses in the Emirate states of Abu Dhabi and Dubai. To compound matters, most existing domestic production is earmarked for reinjection at oilfields and LNG exports. Imports from Qatar (and earlier Oman) through the Dolphin pipeline in 2007 have provided some relief, although the UAE is already asking for the next phase of supplies to increase from 21 bcm per year to 33 bcm per year - as yet without success. Pipeline imports to Sharjah from Iran are still awaited but have been held back by a pricing dispute and some delays in construction. Further pipeline initiatives from Iran have been discussed but have yet to move forward. The Dubai Supply Authority (Dusup) announced in April 2008 that it was building an LNG regasification terminal in the Jebel Ali port in order to open up more supply options. Completion is scheduled for 2010.

Rising international gas prices have had a silver lining for the UAE in making its own significant reserves more commercial. As such, two sour gas fields at Shah and Bab have been tendered for development with foreign contractors. Negotiations on the Shah field are underway, although development costs have been put at a significant USD 4 to USD 5 per Mbtu because of the difficulties in access and the high sulphur content. The integrated gas project and the sour gas development at Hail and Bab are expected to provide additional volumes. Much of this will be required for reinjection to boost production at the country's oilfields. In the longer-term, the UAE is now one of a number of regional states looking at nuclear and renewable energy in order to satisfy its own needs. Further delays in new committed gas supplies from potential regional surplus states like Qatar and Iran are likely to accelerate these moves.

Oman

Oman is making a number of efforts to move forward with its gas–based industrialisation programme, including the sourcing of gas from neighbouring countries, as well as development of its own more difficult reserves. The domestic balance is expected to remain tight for the near-term as evidenced by low throughput at the Qalhat LNG facility which has run below capacity since its commissioning at end-2005. Some relief will be provided by the reversal of the Dolphin pipeline to allow Qatari imports later in 2008. Oman has also fast-tracked development of its own tight gas reserves with international partners, including BP and BG, while tendering five gas blocks for exploration in 2008. A memorandum of understanding was also signed with Iran in 2007 for the development of joint gas fields like Henjam/West Bukha and the supply of gas from other sources. This gas could be liquefied at Oman's export facilities or used internally for industrial purposes. However, the prospects of short-term contributions from Iranian ventures are small.

Yemen

In Yemen, first gas from its 9.2 bcm per year LNG project is due at end-2008, developed by a consortium led by Total. Small volumes of gas will also be made available for domestic use, enabling the country to develop gas-fired power generation. In 2008, Yemen established a purchase price for domestic gas developments of USD 2.50 per Mbtu to provide an incentive for upstream investment. A fourth international licensing round is due to be concluded in 2008, which features some potentially gas-rich areas in the country's offshore acreage.

Saudi Arabia

Saudi Aramco has continued to prioritise the discovery of non-associated gas in its upstream exploration programme. It has laid out plans to increase reserves by an average 142 bcm a year in the next ten years. Some successes have been reported, although efforts with foreign partners in the Empty Quarter have not yet provided new volumes. Development plans are currently focusing on the offshore Karan field, which is now due to supply some 16 bcm per year into the system from end-2011, from initial plans of 11 bcm. Despite some reports of near-term supply constraints, new allocations for petrochemical projects are still keenly sought after because of the low sales price, according to observers. The switch to fuel oil and crude for some new power generation facilities will ease some pressures on domestic gas demand in the medium-term. However, Saudi Arabia remains unlikely to consider any exports of natural gas until it is certain that its own increasing needs are assured.

Iran

Alongside Qatar, Iran remains one of the most promising 'surplus' gas states in the region, although its potential has remained tantalisingly beyond the immediate horizon for some time. Gas production is increasing rapidly as a result of awards at the South Pars field made earlier in the decade, but domestic consumption continues to match and even exceed that pace, leaving limited availability for export. Iran is now the world's third largest gas user. In addition, the slow pace of new upstream awards since 2004, due to changes in political priorities and the international isolation resulting from the country's nuclear ambitions, means that production growth is likely to slow significantly for the first part of the next decade, with later increments dependent on a resurgence in awards in the next couple of years. This will exacerbate some of the existing tensions between the use of gas for domestic industry, power, oilfield reinjection and export projects. A significant large scale pipeline construction programme is underway to address this. In addition, Turkmen import capacity is likely to be expanded from 8 to 13 bcm per year in the period to 2012.

During peak demand periods in the exceptionally cold winter of 2007-08, it was notable that the Iranian government opted to reduce gas flows to both export projects and oilfield reinjection in favour of residential and domestic users. The cut-off in Turkmen imports provided a further illustration of some of the efforts required to bolster the domestic system, with limited infrastructure in place to feed domestic gas supplies to demand centres in northern Iran.

These upstream and domestic demand issues are likely to mean further delays to planned gas export initiatives, with short-distance pipelines or increments through existing infrastructure the most likely outlet for any surplus gas. This includes two short-range pipelines to the UAE and Armenia, which are already behind schedule, in addition to a pledged increase in volumes through the Turkish pipeline for 2009-10 committed to Syria and Swiss-based EGL. In mid-2008, Iran officially postponed two of its three LNG developments focused on South Pars for the 2010-13 period, leaving the domestic Iran LNG in place. Partners Shell and Total are now discussing the prospect of LNG development linked to later phases of the South Pars field. China's CNOOC and Malaysia's SKS have held intermittent talks on LNG development of other fields, but no firm investment commitments have been made as yet. In addition, prolonged negotiations for gas deliveries to the Iran-Pakistan-India (IPI) pipeline mean that this project is now being considered for 2013 and beyond, rather than the original timeframe of 2011.

Regional issues: rising costs and pricing

As mentioned in the 2007 Natural Gas Review, reforms in domestic pricing remain an important ingredient in resolving the constrained gas supply situation in the MENA region. Low prices for domestic users often mean that foreign investors are reluctant to develop new gas reserves where there is no international outlet (and pricing) envisaged – particularly in view of materials constraints and cost escalation. Where domestic state companies are leading developments, they are also faced with rising costs and limited returns as easier gas developments run out. More technically demanding reserves under consideration include offshore

Box 3 Qatar's moratorium

The Qatari moratorium on new gas projects imposed in 2005 now looks set to remain in place until at least 2010 and possibly beyond, as planners continue their ongoing study of reservoir pressure at the North Field, which makes up the bulk of Qatari reserves. Recent comments suggest that new projects are unlikely to be considered until 2011-12, although the country will still witness a doubling in LNG export capacity to 105 bcm per year and a tripling in gas production to 238 bcm per year from projects approved before the moratorium. Within this, Qatar will build six of the world's largest LNG trains of 10.6 bcm per year apiece, the first of which is due online later this year. It will also construct the world's largest gas-to-liquids facility at Pearl GTL with an international partner, Shell. Taken collectively, this will be an remarkable achievement.

However, with the extension of the moratorium and study beyond the initial three-year period envisaged in 2005, concern is growing that the initial results call for greater caution in Qatari policy directions beyond 2012. Of note, the Chairman and Chief Executive Officer of Qatargas, Faisal al-Suwaidi, stated that, 'if I was to start a new train now, I would think again.' He has also suggested that projects beyond the existing cycle would require costly compression technology and would also have the effect of reducing the productive life of the reserves at the North Field.

Sustaining that productive life has been promoted as a key national priority in speeches by Qatari energy officials, taking over from previous priorities which included world LNG market leadership (already achieved) and the maximisation of economies of scale in the LNG project chain (making good progress in the existing project cycle). In particular, officials have mentioned a desire to sustain production levels for the next 100 years to create a sustainable legacy for future generations

Box 3 **Qatar's moratorium (continued)**

– and set the foundations for long-term partnership with gas buyers – which could pave the way for Qatari involvement in other areas of the energy market.

In terms of Qatari policy after the moratorium, or after 2011-12 according to current thinking, some observers feel that the emphasis on sustainability coupled with reservoir pressure concerns – will mean an initial period focusing on exploration and appraisal to ensure that resources are available for further development. This could include exploration at different depths in the North Field area. How and when any future gas reserves are then assigned remains a matter of debate. In the first instance, logic suggests that domestic users will be given first call on reserves – with power generation, desalination and industry all areas of potential growth. This likely priority was evidenced in the re-assignment of Exxon's GTLs North Field reserves to the Barzan domestic gas development after the GTL project was postponed in 2007. If gas reserves are deemed sufficient, next priorities could include the expansion of existing projects to maximise their potential economically – whether that be the debottlenecking of LNG facilities, the maximisation of pipeline capacity or the expansion of GTL facilities. Beyond that, the results of the North Field study and any subsequent exploration work will determine direction.

What is clear is that Qatar is likely to maintain its desire for balance, whether that is in the allocation of reserves between exports and domestic use, or in the form of marketing its gas - between GTL, LNG and pipelines, or in the choice of markets themselves – regional, Asia-Pacific or Atlantic basin. This policy means that the emirate will remain relevant in multiple spheres of the gas market for the foreseeable future, even if its growth rates are unlikely to revisit the extra-ordinary levels breached in the current project cycle – in part because of the higher starting base.

reserves in North Africa and the Gulf, sour gas reserves in the UAE and tight gas formations in Oman – all of which will entail higher development costs than existing associated and non-associated gas. Estimated development costs for the Abu Dhabi Shah gas project are estimated at up to USD 5 per Mbtu, compared to current domestic prices of around USD 1 and USD 1.30 per Mbtu for imports from Qatar. Same in Oman, where development costs of tight gas – and proposed imports from Iran – are likely to significantly exceed domestic prices of under USD 0.80 per Mbtu. Saudi's offshore Karan development is likely to be another project to put the domestic price in the shade.

North African states, Egypt and Libya, have been the first to try to tackle this issue in terms of improving incentives for foreign investors. Over 2007-08, Egypt has negotiated an increase in offshore gas purchase price from USD 2.65 per Mbtu in staged caps as high as USD 3.95 per Mbtu and a reported USD 4.7 per Mbtu in the case of BP and RWE's Raven field. In order to relieve the pressure of higher purchase prices on the state budget, Egypt is also looking at a staged increase in prices for the most energy-intensive industries under a three-year programme announced in 2007. Meanwhile, Libya is reported to have offered a price of 15% below international prices for gas purchases from the blocks offered in its licensing round of early 2008.

More marginal producers including Syria and Bahrain have also started to reform domestic pricing structures in order to reduce subsidies. Bahrain is working on a four-year programme to increase gas pricing to USD 1.50 per Mbtu. This is still very low by international standards, but already represents a 50% increase on 2007 levels. In the more gas-rich states of the region, discussions have centred on the benefits of increasing domestic pricing in terms of efficiency and revenues versus the advantages that low prices give to promoting gas-based industrialisation and employment opportunities. Where imports are being sought, there is little question that these will be at higher levels than those negotiated in previous sales, most notably the current Dolphin pipeline sales reported at USD 1.30 per Mbtu. Indeed, Dubai was reported to decisively break through the regional ceiling in 2008 with a 15-year deal of up to 4.1 bcm per year from Qatargas and Shell reported to be priced over USD 8 per MBtu according to the Middle East Economic Survey.

Concluding remarks

There are a number of reasons to be pessimistic about the situation of the MENA gas production in the medium-term horizon despite the resource wealth of a number of states in both the Gulf and North Africa, and the undisputed success of major expansion projects in Qatar and Algeria. Pricing remains one key constraint to new development, limiting investment incentives for foreign partners and often indirectly restricting the funds available to state–owned companies because of subsidy costs. The level and speed of development funding is also a concern in the Gulf states outside Qatar and Oman. In addition, problems at the political level have blocked the development of regional gas networks beyond the Arab gas and Dolphin pipelines, which prevents the region from maximising gas resources between gas-rich states and those requiring gas. Moreover, an estimated 50 bcm of associated gas is being flared across the region each year. Only Algeria has signed up to the World Bank's voluntary Global Gas Flaring Reduction partnership to date, although Qatar and Kuwait have expressed an interest.

Until some of these issues are addressed, it is likely that where flexibility exists, producer states will continue to look to cannibalising gas from export projects and even oilfield reinjection, in times of peak domestic demand. Sustained shortfalls over the medium-term are also likely to promote a greater systemic reversal to the use of oil and oil products in order to provide feedstock for the next generation of power generation and desalination. The region's major refinery expansion programme is likely to encourage this trend by making more products available, with implications for oil export volumes and pricing, as well as the region's own consumption-based carbon footprint.

China

China's rapid economic growth shows no signs of abating with a gross domestic product (GDP) increase of 10.6% reported in the first quarter of 2008[32] and an annual growth rate of 9.4% forecast for the year.[33] China is now the world's second-largest and fastest-growing energy consumer and is a major player on world energy markets. Growth in energy demand has been driven by industrial output of manufactured goods for domestic and export markets and for building materials (steel and cement) for the substantial local construction sector.

Gas remains a small part of China's rapidly growing energy demand. Coal is the corner stone of the country's energy system and it meets just over 60% of its primary energy demand. Natural gas comprises approximately 2% of total primary energy demand but this seemingly small share hides the significance of the large volumes of natural gas consumed. In 2007 China consumed 67.3 bcm of natural gas, an increase of 20% on 2006 volumes, of which 4 bcm was imported as LNG through the Guangdong terminal. Domestic production of natural gas in China was up 18% in 2007 over the previous year, reaching 69.31 bcm compared with 58.55 bcm in 2006. Most of the gas is still produced from the far west of the country, meaning increased production will not have a great impact on the LNG terminals planned for the eastern seaboard, despite a variety of pipeline projects to connect the regions. China also exports gas to Hong Kong in small volumes. These exports come from the Yacheng gas field off Hainan Island and some additional regasified LNG; therefore they are independent from the domestic gas system on the mainland.

LNG imports were up on 2006 levels, from 1 bcm to 4 bcm. The bulk of LNG sourced in Australia with an average of four cargoes per month arriving since September 2007. Over the year, China bought seven spot cargoes from Oman, Nigeria and Algeria but this practice was halted in early winter following an escalation in regional spot prices until April 2008. Mid-2008 has seen China prepared to pay very high prices for spot LNG imports.

Gas-fired power generation

Despite the impressive growth rates for nuclear energy and hydropower, thermal power represents by far the largest single component of China's power generation mix, holding a share of around 85%. Of this, the vast majority is coal-fired with natural gas representing little more than 2.5% of installed capacity.

Recently, gas-fired generation has suffered from the combined effects of supply constraints and high gas prices. Natural gas is not competitive with coal

32. *National Economy: Steady Growth in the First Quarter of 2008*, National Bureau of Statistics of China, April 2008.
33. *Key Country Macro-Indicators*, World Bank, April 2008.

Map 7 China natural gas 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: Petroleum Economist and IEA.

under current market conditions, but government policy aimed at diversifying the electricity mix and reducing local pollution should increase the share of gas in some regions and in particular along the Yangtze River Delta region. By the start of 2008, China had 69 gas-fired generators operating some 17 500 MW of capacity. The bulk of this capacity, 85%, is to be found in coastal areas and includes the cities of Guangdong, Fujian, Zhejiang and Hainan. Most of the gas consumed in the region is sourced domestically, either from inland fields or from off-shore resources. The exception to this is Guangdong, which sources much of its gas from the Dapeng LNG terminal on the eastern side of the Pearl River delta in southern coastal China.

Additional LNG infrastructure is being build to meet the immediate shortfall as demand for gas continues to outstrip domestic supply. China received its first LNG shipments to the Dapeng terminal in 2006 and another terminal opened in Fujian province in April 2008. Construction of a further two terminals near Shanghai and Dalian, Liaoning, in the northeast, is underway. Some engineering work is also in progress at the planned Rudong terminal in Jiangsu. Growth in gas-fired generation will be strongly linked to additional import capacity and the price of imported LNG. Additionally, growth in gas-fired generation will to some extent be linked to electricity price reform. Some generators in the Guangdong Province rely on government subsidies to maintain output as there is a disconnection between the price at which they purchase LNG and that at which they are allowed to sell their power.

In February 2008 the Guangdong Provincial Pricing Bureau raised the price the government guarantees generators will earn in order to maintain output. Without government subsidies generators will suffer operational losses. Further increases will be provided should LNG prices rise above an agreed threshold during the coming year. These measures were implemented to encourage electricity generation by gas-fired power plants, as Guangdong's power shortage was severe at that time.

Gas supply

As China's economy continues to expand, the gap between energy supply and potential demand continues to grow. This is having a two-fold impact on Chinese energy policy; firstly investment in energy resources within China is growing and secondly, development and investment in foreign energy assets is becoming more important. In addition, large investments are being made in both pipeline infrastructure and in LNG facilities.

Turkmenistan

Following the signature of a General Agreement on Gas Cooperation in April 2006, cooperation with Turkmenistan has proceeded along three interrelated lines. Firstly, the allocation to the China National Petroleum corporation (CNPC) of a PSA for reserves on the right bank of the Amu Darya river (eastern Turkmenistan), was finalised in July 2007. Secondly, a natural gas sale and purchase agreement for 30 bcm per year for 30 years, was also signed in 2007. Finally, the agreement between the countries on the construction of a new pipeline from Turkmenistan to China, was reached in mid-2007. Construction of this new pipeline began in late 2007.

After the opening of the relatively small-capacity Turkmenistan-Iran pipeline in 1997, the opening of a major eastern export route for natural gas would greatly expand the non-Russian routes for gas export from Central Asia. In April 2007, China signed an agreement with Uzbekistan on pipeline construction and this was followed by the July signature of the gas supply contract. In November a China-Kazakhstan agreement on pipeline construction and operation was reached. In December 2007, CNPC announced that it will invest USD 2.16 billion in the pipeline project which would link up to China's West-East pipeline, with the total cost estimated at USD 7.31 billion. China expects first deliveries of gas at the beginning of 2010.

Production

Within China, Chevron is understood to have been awarded rights to help develop the PetroChina Loujiazhai sour-gas field in south-western Sichuan province. Although the gas is sour – meaning that it contains significant amounts of hydrogen sulphide, requiring special handling equipment, drilling and production technology to ensure safe operations – there are proven reserves of 58.11 bcm. If this development is successful it may open the way towards further development of the nearby Tieshanpo and Dukouhe sour-gas fields, whose proximity to urban populations have deterred previous investment despite high levels of proven reserves. Further developments elsewhere in the region, most notably in the Sichuan basin, have stalled due to the lack of sour-gas expertise within PetroChina.

PetroChina is also in partnership with Total of France for the joint exploration and production of gas from the Sulige gas field in the Ordos basin in northern China's Inner Mongolia Region. The field is the largest in China with proven reserves of 534 bcm and is near the West-East gas pipeline, which links western China with major customers in Shanghai and Nanjing. The company has also entered into an arrangement with Shell to jointly explore the Changbei field, also in the Ordos basin, where commercial production was understood to have commenced early in 2008.

Further exploration of the Puguang field in Sichuan province is expected this year despite the recent scaling down of reserve estimates following a reduced certification of proven reserves from the Ministry of Land and Natural Resources. The field holds proven natural gas reserves of 356 bcm, making it China's second largest field after the Sulige field. China's Sinopec will drill nine production wells in 2008 as it moves towards full start-up of phase-one development of the field. The company states that another 15 wells would start production in 2009. The company expects that the field will have a production capacity of 10 bcm in 2008.

CNPC and Russia's Lukoil have entered into a strategic partnership agreement under which they intend to expand cooperation on projects within Russia and also to join forces elsewhere. Currently, the partnership is working together on two projects in Kazakhstan, on developing the Kumkol field in the Kyzylorda region and on the North Buzachi project in the Mangistau region. Both parties also have stakes in the Uzbek part of the Aral Sea.

China's recent drive for long-term LNG procurement

China's ability and willingness to import LNG is growing. In April 2008, PetroChina started building its planned LNG import terminal in Dalian, Liaoning, in the northeast of the country. While the company is the largest natural gas producer and seller in the country, the Dalian terminal would be its first LNG receiving terminal. The project was granted final approval from the central government's National Development and Reform Commission (NDRC) in February, after the company secured a preliminary supply deal by signing a long-term agreement with Qatargas IV for 4.1 bcm per year of LNG beginning in 2011, corresponding to the project's first phase. NDRC has strict criteria on approving LNG receiving terminal plans in the country, including securing LNG supplies. The eventual capacity would be 10.6 bcm per year after completion of a second phase. The company has several additional LNG receiving terminal plans: Rudong, in the eastern Jiangsu province; Caofeidian, in the northern Hebei province; and Shenzhen, in the southern Guangdong province. A man-made island for the proposed Rudong terminal was completed in March 2008 in the Yellow Sea.

In September 2007, PetroChina signed a binding heads of agreement (HOA) to buy 1.4 bcm per year of LNG for 20 years from Royal Dutch Shell's share of planned output from the proposed Gorgon LNG project in Western Australia. However, the project is not expected to come online before 2014. A few days later, PetroChina also signed a key terms agreement with Woodside Petroleum to buy 2.7 - 4.1 bcm per year for 15 - 20 years from the Australian company's Browse Basin project in Australia, starting sometime between 2013 and 2015.

The country's LNG business pioneer, China National Offshore Oil Corp. (CNOOC), is also active again in long-term LNG procurement activities. In June 2008, it signed a purchase agreement for 2.7 bcm per year of LNG, starting in 2009, from Qatargas. It also signed a memorandum of understanding with Total for 1.4 bcm per year of LNG for 20 years starting in 2010. These would be the fourth and fifth long-term LNG purchase contracts for CNOOC, following deals with North West Shelf (NWS) of Australia for the Guangdong terminal, Tangguh of Indonesia for the Fujian terminal, and Malaysia LNG Tiga for the planned Shanghai terminal. The supply from Qatargas is likely to be assigned to the Guangdong and Fujian terminals.

Table 34 Long-term LNG purchase deals by Chinese companies

[Buyer], Supplier	Annual volume	Duration	Status
[CNOOC]			
North West Shelf, Australia	4.5 bcm	2006-2030	SPA signed in December 2004, following a preliminary deal in October 2002
Tangguh, Indonesia	3.5 bcm	2008-2032	SPA signed in September 2006, after a preliminary deals in 2002 and renegotiation of pricing terms
Malaysia Tiga	4.1 bcm	2009-2033	SPA signed in July 2006
Qatargas	2.7 bcm	2009-2033	HOA signed in April 2008, SPA signed in June 2008
Total	1.4 bcm	2010-2029	MOU signed in June 2008
[PetroChina]			
Qatargas IV	4.1 bcm	2011-2035	SPA signed in April 2008
Qatargas III	1.4 bcm		Pending
Shell, Gorgon, Australia	1.4 bcm	2014-2033	HOA signed in September 2007, targeting SPA in 2008
Woodside, Browse, Australia	2.7-4.1 bcm	15-20 years from 2013-2015	KTA signed in September 2007
[CLP (Hong Kong)]			
BG	1.4 bcm	2013-	HOA signed in June 2008

"SPA" = sale and purchase agreement
"HOA" = binding heads of agreement
"MOU" = memorandum of understanding
"KTA" = non-binding key terms agreement

Chinese LNG importers' recent deals with Australia and Qatar have been seen as indications that the Chinese buyers are now accepting much higher international gas prices. Although the impacts of the higher prices are expected to be mitigated to some extent by blending with lower priced supply sources: in case of PetroChina, abundant domestic gas production; and in case of CNOOC, lower-priced LNG from previously contracted supply sources, including NWS (even at current oil prices this contract is in the range of USD 3.10 – USD 3.20 per MBtu), Tangguh and Malaysia Tiga. Still, it is not entirely clear how the companies and the government will handle gas pricing issues in China's gas market when the higher priced LNG starts to be delivered at full scale.

Collectively, all of these deals amount to nearly 30 bcm annually, although some are quite distant from realisation. China is now emerging as a major LNG importer; at these volumes it would be on a par with Korea or Spain, the second and third largest LNG markets.

Recent policy changes

September 2007 – new policy of gas use

In September 2007, NDRC enacted a new industry policy on natural gas use with the intention of addressing supply shortages and optimising consumption, and to maintain a long-term balance in gas supply and demand. The policy makes residential gas use a top priority, while usage in petrochemical plants is discouraged. The policy became effective in late August 2007 following approval by the State Council.

New methanol projects that use gas as a base are to be barred as will the use of natural gas in other petrochemical projects and power-generation plants. For example, gas-fired power plants will be banned in certain coal-rich regions. Existing gas-based petrochemical projects, especially fertilisers, will remain in operation. Approved and under-construction projects, which have signed long-term gas-purchase contracts, won't be affected.

White Paper on Energy

In late December 2007 the State Council Information Office published its first ever white paper on China's Energy Conditions and Policies. Amongst other things the paper sets out the country's strategy and goals of energy development, the need to improve supply capacity and progress in new technologies, the coordination of energy and environment development and the strengthening of international cooperation in the field of energy.

India

Production and consumption

India's gas consumption during fiscal year 2007-2008[34] increased to 38 bcm, up from 35.6 bcm, or 6.5% on the previous year. Increased consumption was met mainly

34. India's fiscal year runs from April to March. Data source: http://ppac.org.in/GAS/gas.htm.

by higher LNG imports supplementing lower domestic production growth, which increased by only 2.1% to 32.4 bcm from 31.7 bcm over the same period. This moderate increase in production is due primarily to higher output from privately owned joint ventures.

Private sector Reliance Industries is set to produce 40 mcm per day by the third quarter of 2008, from its Krishna-Godavari (KG) field off the country's eastern coast, to be doubled by 2010. Hence, by 2009 domestic production is expected to reach more than 120 mcm per day after the new gas field becomes operational. Other new gas is also expected to come on-stream from fields explored by Gujarat State Petroleum Corporation (GSPC) and Oil and Natural Gas Corporation (ONGC) although the starting date of production remains uncertain.

Evolution of gas demand

Potential gas demand in India was estimated to be around 67 bcm per year for the fiscal year 2007-2008. Since LNG imports started in 2004, the demand-supply gap has been partially reduced but there is still a large volume of unsatisfied demand. Dominant gas consumers are the power and fertiliser sector, accounting for over 80% of total consumption.

The situation of the power sector is a good illustration of the impact of the gap between demand and supply. India's installed gas-fired power production capacity is about 13 GW. The Central Electricity Authority (CEA), an advisory body to the government that monitors developments in the country's power sector, estimated that running the installed capacity at a 90% plant load factor (PLF) would require 24 bcm per year. However, natural gas available to the power sector during November 2007 was little more than half that amount; consequently, the average PLF was only 53%.

In addition, almost 1 300 MW (requiring 6 mcm per day at a 90% PLF) of gas-fired capacity has not yet been commissioned due to shortages of gas and about another

Table 35 Indian gas supply and consumption balance in recent fiscal years

Fiscal year	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	(yearly growth) 2006/07 - 2005/06	(yearly growth) 2007/08 - 2006/07
Supply (gross)	29.7	31.4	32.3	35.1	39.0	41.0	43.6	5.3%	6.3%
Gross domestic gas production*	29.7	31.4	32.0	31.8	32.2	31.7	32.4	-1.4%	2.1%
LNG imports			0.3	3.4	6.8	9.3	11.2	37.3%	20.6%

Unit: bcm
*Gross domestic production includes flared gas and auto-consumption by producing companies.
Source: Petroleum Planning and Analysis Cell, Ministry of Petroleum & Natural Gas, Government of India (http://ppac.org.in/).

1 000 MW (requiring another 5 mcm per day) are using liquid fuels such as naphtha to substitute for insufficient gas supplies. Thus, total potential power sector demand for natural gas, at PLF of 90%, can be estimated at 28 bcm per year. This equates to more than 90% of the current net production.

At the same time, while significant installed capacity sits idle, India suffers power shortages in the order of 10%, and reaching over 14% during the peak demand period. Part of the shortfall of domestic gas production has been met through LNG imports.

LNG outlook

LNG imports continue to grow strongly. The capacity at India's first LNG terminal at Dahej, in Gujarat state, has been expanded by 30% beyond its optimal installed capacity to 8.9 bcm per year through debottlenecking and an expansion project. In addition to the 6.8 bcm per year of long-term supply from Qatar's RasGas, Dahej's owner and operator Petronet LNG imported 1.5 bcm of spot and short-term LNG cargoes in 2007.

Dahej's capacity is currently being expanded to 17 bcm per year. Petronet has secured an additional 3.4 bcm per year from Qatar for the expanded Dahej terminal from 2009. In the interim, the company is actively looking for spot and short-term LNG to reduce the supply deficit.

Petronet is also searching for other long-term supplies, including Papua New Guinea, Algeria, Oman, Egypt, Trinidad and Tobago, as well as Qatar.

In addition to the expansion of Dahej, Petronet is also progressing with the construction of its second LNG terminal in Kochi, in the southern state of Kerala. Completion of the terminal is expected by mid-2011 with a capacity of 7 bcm. Unlike for Dahej, Petronet has not yet been able to sign a long-term LNG supply contract. Petronet announced a negociation with ExxonMobil for its share, 3.4 bcm per year, of the Gorgon LNG project in Australia and its LNG project in Papua New Guinea. Although progress on the Gorgon project is slow, Petronet has already expressed interest in increasing the quantity to 5.1 bcm per year. Even if the negotiation is completed successfully, Gorgon is not expected to commence production before 2014; similarly, output from Papua New Guinea project is not expected before 2013. This would require Petronet to find other supply sources for at least the one or two year period between completion of the terminal and beginning of production.

Petronet is being supplied with an additional 1.7 bcm of short-term LNG from July 2007 to August 2008 by Rasgas, to provide gas to the Ratnagiri power plant in Dabhol, through a newly-built 581 km pipeline. An additional 7.5 bcm per year Ratnagiri LNG receiving terminal is being completed in Dabhol to eventually supply the power plant, which was originally constructed by now-bankrupt Enron, but the projected start-up date of the terminal has been delayed to 2009.

Pricing issues

The issues surrounding identifying long- and short-term LNG supply reflect the dilemma the Indian gas sector is facing. International gas prices have increased substantially since India started to import LNG in 2004. Indian domestic production, especially from the private sector, was expected to have come on-stream much earlier. But issues related to transportation and pricing have continued to delay new production.

At the same time, the dominant Indian gas consumers are still not geared up to accept the rapidly rising international prices and the domestic "pain" threshold is still much lower than prevailing and likely international prices.

Progress was made in September 2007 when the government, after extensive and prolonged discussion, finally came forward with a pricing formula for domestic production. The price for Reliance gas from the KG basin was set at a minimum of USD 4.2 per MBtu – below the maximum price of gas from joint venture western off-shore fields. The pricing formula for the Reliance supply is widely seen as setting a benchmark for future gas pricing in India.

Gas utilisation policy

The Indian government is in the process of finalising a so-called "Gas Utilisation Policy". The major purpose of the policy is to ensure that important industries like fertiliser and power will be ensured certain portions of gas supply. Hence the draft policy suggested specific shares of gas to be allocated to priority sectors. First priority would be the fertiliser sector, followed by the petro-chemical industry and the public sector and gas-fired power sector. It is important to note that the allocations fall short of the identified actual demand of those industries.

The policy is likely to counter efforts to increase production of the domestic gas sector. This is likely to have significant implications for new investments in the sector, as the policy will also be applicable to private sector gas production from new and existing fields, like the Reliance KG field and the already producing PMT off-shore fields.

Transportation infrastructure

India's gas pipeline and gas distribution policy (effective since end 2006), promotes private pipeline investment. It was the starting signal for the proposed East-West pipeline that is being constructed by Reliance Industries to transport its gas from the east coast to consumers in the south and the west. This pipeline will connect with public-sector GAIL's pipeline network at three points throughout the country. With 1 400 km, the pipeline will be the longest in India and will traverse three states. The pipeline is expected to be commissioned by the end of 2008.

A long-awaited proposal to import gas from Iran to Pakistan and India through the proposed Iran-Pakistan-India pipeline made only slow progress, with a burst of new discussions in April and May 2008. Significant issues remain to be resolved, *i.e.* pricing and transit. This project is not expected to be complete until at least 2013.

A second regional gas pipeline proposal, the Turkmenistan-Afghanistan-Pakistan-India (TAPI) is also advancing cautiously. According to a framework agreement signed between the ministers of the four countries in spring 2008, construction is scheduled to begin in 2010 and operations to start in 2015.

Map 8 Indian gas 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: Petroleum Economist and IEA.

Southeast Asia

Traditionally, the demand for gas in Southeast Asia was satisfied by gas producing countries within the region. Recently, demand for energy has accelerated; the challenge will be to ensure that gas supply meets this increasing demand, given that the alternative is likely to be oil products.

Indonesia, the biggest LNG exporter in the region, is experiencing falling LNG production. Other producing countries, such as Malaysia and Brunei, are expected to offer modest prospects of additional volumes. Issues of resource nationalisation also arise regularly within the region. Another obstacle to the development of oil and gas reserves is recurring border disputes i.e. the Brunei and Malaysia dispute, overlapping claims areas between Thailand and Cambodia in the Gulf of Thailand, and various countries' claims on the Spratly Islands. The exploration and development at these areas could be intensified if the affected countries could resolve these disputes, and allow for example joint-sharing of benefits. An example of this is the joint development area (JDA) model that was successfully adopted by Malaysia and Thailand for Block A-18 in the Gulf of Thailand, which started to produce gas in 2005, following a similar example of the Bayu Undan joint venture project in the Joint Petroleum Development Area (JPDA) between East Timor and Australia. That venture started

LPG and condensate production in 2004, before exporting LNG from Darwin, Australia in 2006.

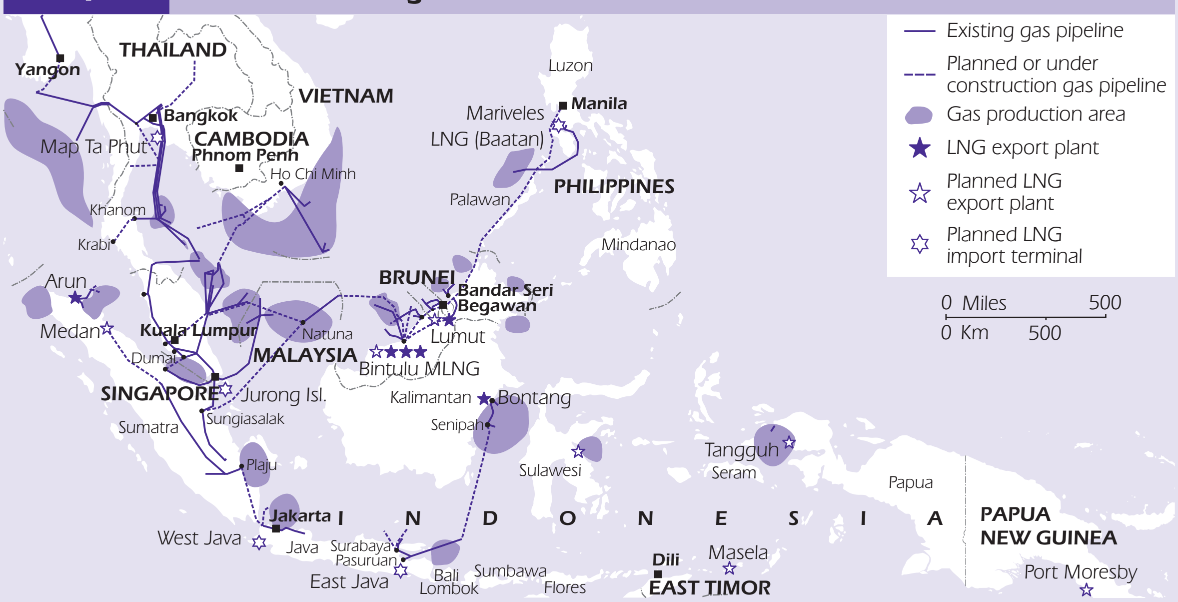
Overall, and despite these obstacles, there are reasonable prospects for untapped gas resources in Southeast Asia, with new players emerging in the region's gas market like Papua New Guinea and East Timor.

Brunei Darussalam

Brunei, which was a pioneer in the development of liquefaction plant in Western Pacific, is currently the world's tenth largest LNG producer; oil and gas exports account for more than half of its GDP. The majority of its gas is exported under long-term contracts; 90% of its LNG goes to Japan and the remainder is sold under long-term contract to Korea's Kogas. In addition to export, gas is consumed domestically in electricity production, petrochemicals and other energy intensive industries. Close to 100% of electricity is gas-fired.

Brunei is intensifying its efforts in the exploration and development of new fields to enable it to extend its contracts with Japan and South Korea subsequent to the expiry of the current contacts in 2013. The recent Bubut offshore gas discovery, 15 km from Brunei LNG (BLNG) by Brunei Shell Petroleum Company Sdn Bhd, a joint venture between Shell and Brunei's government, offers hope for possible contract extension beyond 2013. Efforts are also being made in rejuvenating its 36-year old LNG facility. This project, which commenced in 2004, is expected to be completed in 2010 extending the plant life to 60 years.

Map 9 **Southeast Asian gas infrastructure**



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Source: Petroleum Economist and IEA.

Malaysia

Supply

Malaysia started commercial production of gas in the 1970s. However, gas only started to play an important role in the Malaysian economy with the first shipment of LNG to Japan in 1983 and when the Peninsular Gas Utilisation (PGU) system phase one came on stream in 1984. Gas production has expanded significantly since 1984, from 11.3 bcm, to almost 60 bcm in recent years. Malaysian natural gas reserves stood at 2 480 bcm in 2007.

Domestic supply in Malaysia comes largely from three main sources: offshore Terengganu (Malay Basin) to cater for domestic demand in Peninsular Malaysia, Sabah Offshore fields (Sabah Basin) for Sabah's domestic gas consumption and offshore Sarawak (Sarawak Basin) mainly for LNG exports.

Peninsular Malaysia is a net importer of gas as supply from offshore Terengganu is insufficient to meet local demand. Hence, Malaysia is sourcing its gas requirements for Peninsular Malaysia from the Joint Development Area (JDA) which jointly operated by Malaysia and Thailand (15%) and from West Natuna, Indonesia (10%). Sarawak on the other hand, is a net exporter of gas via its LNG production.

Malaysia's Peninsular Gas Utilisation (PGU) system was completed in 1998 and now spans over 2 000 km of pipelines. The PGU system not only delivers gas to domestic gas users in Peninsular Malaysia but is also used to export approximately 1.6 bcm of gas per year to Singapore. It is also connected in the north to the Trans-Thailand-Malaysia Gas Pipeline System in Southern Thailand allowing gas from the JDA to flow to Malaysia. The pipeline systems in both Sabah and Sarawak are not as extensive as the PGU system as most gas users are located within 20 km of onshore gas terminals.

Supply outlook

Despite the government's recent decision to increase domestic gas prices by more than 100% in some cases, gas consumers still enjoy heavily subsidised prices. This pricing concept, coupled with large increases in production costs, represents a great challenge to sustaining gas supplies and to enhancing security of supply at a time of growing gas utilisation. This is very much apparent in Peninsular Malaysia. The rapid decline rates of producing fields

Table 36 Malaysian gas prices

Sector	New price effective 1 July 2008 (MYR per MBtu)	Previous gas price (MYR per MBtu)
Power sector	14.31 (USD 4.40 per MBtu)	6.40 (USD 1.97/MBtu)
Reticulation (average)	22.06 (USD 6.78 per MBtu)	9.40 (USD 2.89 per MBtu)
Industry	23.88 (USD 7.34 per MBtu)	11.32 (USD 3.48 per MBtu)

MYR: Malaysian Ringgit
USD 1.00 = MYR 3.2540 (average June and July 2008 as quoted by Bank Negara).

and the lead times required to develop new fields are adding to gas security concerns. Despite this, Malaysia has no plans to build an LNG import terminal, unlike neighbouring Thailand, Indonesia and Singapore.

The Sabah Oil and Gas Terminal (SOGT) was launched last year and is expected to transform Sabah's economy. This terminal which receives, stores and exports oil and gas will boost the hydrocarbon industries in Sabah, particularly in the Kimanis area. The terminal is designed to receive 180 000 b/d of crude from the Gumusut, Kakap and Malikai Fields and 5.2 bcm and 7.2 bcm per year of gas from the Kinabalu and Kebabangan fields. This development will complement the existing Labuan Gas Terminal, Sabah Gas Terminal and Crude Oil Terminal in Labuan.

In addition to the SOGT, the 500 km Sabah-Sarawak Gas Pipeline (SSGP) project is expected to deliver gas from Kimanis in Sabah to the existing LNG plants in Bintulu from 2011.

The offshore fields of Sarawak will continue to be the main feed to LNG plants in Bintulu with gas from Sabah via SSGP to complement supply.

In the future, LNG will be in the key factor driving Malaysia's gas production. Malaysia is diversifying its LNG portfolio by signing a long-term contract with China, and trading in spot markets, in addition to its traditional markets (Japan, Korea and Chinese Taipei).

Demand

Malaysia has three primary demand centres: Peninsular Malaysia, Sabah and Labuan, and Sarawak. The power sector is the largest consumer of gas in Peninsular Malaysia consuming almost two-thirds of the total gas volume. In Sabah and Labuan, demand for gas is mainly for methanol production and electricity generation. As noted above, production from offshore fields of Sarawak is chiefly for LNG export at the Bintulu complex.

Gas prices in Malaysia are pegged to regional fuel oil prices. However, due to the 1997 economic crisis, gas prices for all downstream gas users in Malaysia have been subsidised. This pricing system was revised in June 2008 and is summarised in the following table.

Subsidies are set to decline progressively at a rate of 5% per year. The power sector however, will continue to enjoy subsidies until 2022, while the subsidy to non-power consumers, notably to industrial users will expire in 2017.

The historically high levels of subsidy led to a significant number of customers converting their market-priced coal, LPG, diesel or fuel oil to gas. Currently, all available gas has been committed under long-term agreements with customers.

Demand outlook

Demand for gas is expected to continue growing for both modes; LNG for export and through pipelines. As long as the gas price continues to be subsidised domestically, demand for gas will be artificially high. However, the impact of 2008 revision of subsidies is hard to gauge at this point in time but given that market prices for alternative fuels are much higher than gas despite the falling subsidies, it can be expected that demand for gas will remain high.

Concluding remarks

Malaysia faces several challenges to fulfill its LNG contractual commitments as production from offshore Sarawak declines. Supplies from Sabah could compensate for this gap when the pipeline to Bintulu is complete.

Pricing reform is necessary to ensure affordability and to enhance the competitiveness of the economy, as well as encourage investment in supply. The current imbalance should be rectified over time as subsidies decline.

Indonesia

Supply

Indonesia has commercial gas reserves of 2 659 bcm, the largest in the region. A significant amount of reserves were discovered in 2006 and 2007 as a result of increased issuing of licences for exploration and development.

Pipeline systems throughout Indonesia, to some extent, cater for the geographical mismatch between the main demand centres in Indonesia, Java and Bali, and some of predominant supply sources in Natuna Island and South Sumatra. Other supply regions, such as Kalimantan and Papua, are not connected by pipelines with the largest consuming regions. Due to this mismatch, several LNG import terminals are being considered in East Java, West Java and North Sumatra to complement the existing and future pipeline system. However, in order for these projects to be developed, gas supplies need to be secured and markets for the gas identified.

Indonesia is expected to play a vital role in the supply of gas in Southeast Asia due to its abundant gas reserves. Currently, several Indonesian pipelines are linked to its neighbours *i.e.* pipelines from West Natuna to Singapore and Malaysia and South Sumatra to Singapore.

With the current emphasis on domestic gas to replace oil consumption, the Government has plans for more gas to be made available domestically. The Indonesian government's approach for speedier approval processes and more transparent tenders hopes to encourage more participation from international and domestic players in exploration and appraisal activities.

Demand

Under the Oil and Gas Law (Law 22 of 2001), buyers may negotiate directly with production sharing contractors (PSC). This law has dramatically changed the role of Pertamina (a state-owned company) which was formerly the exclusive holder, on behalf of the government, of all the oil and gas exploration rights. These rights have now been phased out. Another significant change is the obligation for up to a quarter of gas volume to be allocated for the domestic market, which applies to new contracts. This law, coupled with open access to pipelines, should spur increases in domestic gas demand, provided its implementation is made clearer.

Historically, the production of gas was geared for the export market but due to the depletion of Indonesia's oil reserves, efforts are being made to shift from oil to gas in the energy mix.

Three new LNG receiving terminal projects have been identified for domestic gas demand. Although there are indications from government officials that some portions of national LNG production are to be allocated to domestic receiving terminals, this has yet to be agreed with shareholders.

The largest users of gas in Indonesia are power plants, followed by industrial users, and fertiliser and petrochemical plants (using gas as feedstock).

Traditionally, gas prices in Indonesia have been low. During the period from 2000 to 2004, gas prices ranged between USD 2.50 and 3.50 per MBtu. However, prices have been rising steadily and the new contracted gas is expected to be priced even higher.

As the government is withdrawing subsidies on oil from the domestic industry, more demand for gas is expected. Furthermore, the price of gas is currently well below the price of oil, and this will stimulate further shifting energy demand from oil to gas.

Indonesia's dilemma

Although LNG exports from Indonesia have been declining for some years, the country still has a significant potential for gas resource development. Clear gas pricing and investment policies would encourage private sector investment. Even though export volumes have been cut, Indonesia should continue to be one of the region's most important energy suppliers.

Indonesia is the eighth largest gas producing country in the world, and the largest gas producing country in Asia. It produced 72 bcm of gas in 2006, out of which 30 bcm was exported as LNG and 5 bcm was exported to Singapore via pipeline. Major production regions are: East Kalimantan (including Bontang LNG); Sumatra (including a pipeline to Java, Arun LNG and a pipeline to Singapore); West Natuna (a pipeline to Singapore); Papua (developed for Tangguh LNG); and Sulawesi (potential LNG).

Indonesia enjoyed the status of the world's largest LNG exporter for 22 years. It lost that status to Qatar in 2006, as in recent years contractual LNG deliveries have been cut because of dwindling feedgas production and a slower-than-expected rate of gas reserves replacement. The decline in reserves is most prevalent in the East Kalimantan fields that supply the Bontang liquefaction plant. The other LNG liquefaction plant in the country, the Arun plant in North Sumatra, has been phasing down production since 2004, as feedgas reserves are depleting rapidly.

Contract delivery shortfalls

Since 2005, Indonesia's state company and LNG marketer Pertamina has negotiated the rescheduling and reduction of contractual LNG sales to buyers in Japan, Korea and Chinese Taipei. Because of declining production from production sharing contractors (PSCs) Vico and Chevron, the Bontang plant has been reducing LNG exports. Total has somewhat

Table 37 Indonesia's gas balance and annual growth

	2000	2003	2006	1990s*	2000s*	2006/2003*	2003-2006**
Production	72.2	75.7	72.1	4.0%	0.0%	-1.6%	(3.6)
Exports	36.4	38.4	34.9	2.8%	-0.7%	-3.1%	(3.5)
Consumption	35.1	37.3	37.1	4.7%	0.9%	-0.2%	(0.2)

Unit: bcm, *annual growth (change),
**change in bcm.
Source: IEA.

compensated for other producers' declines. Affected volumes have been 10% - 12% of the original contractual volumes, or 3 - 4 bcm per year. Indonesia's total LNG production is expected to be 24.5 bcm in 2008, compared to the peak of 36 bcm in 2003, and 30 bcm in 2006.

The rapid growth of domestic consumption is also often mentioned as a cause of the reduction of LNG, as the government wants to replace the consumption of subsidised oil products (which are imported at much higher prices) with domestically produced gas. However, in the country as a whole, gas consumption increased at an average annual rate of only 0.9% during the period between 2000 to 2006, whereas total gas production did not change significantly during the same period and LNG exports declined by 3.2% per year on average (at the same time pipeline exports increased to virtually offset LNG export reduction). During the period between 2003 and 2006, both total exports and total production decreased by 3.5 bcm per year.

Thus in explaining the reduction in LNG exports, the reduction in gas production around the LNG plants has been a much bigger factor than domestic demand growth. The latter is rather a factor for the future gas balance, depending on how much oil in the country's domestic consumption will be replaced by gas and how much coal will be used to replace oil and gas; the overall effect is therefore quite uncertain.

However, thanks to higher oil prices which are used to determine prices of LNG, Indonesia is expected to earn more for less LNG exports. In fact, according to Japan's customs statistics, Indonesia earned USD 5 940 million in 2007 from LNG sales to Japan, compared to USD 5 860 million in 2006, for slightly lower exports of 18.48 bcm in 2007, compared to 19.02 bcm in 2006. The net impact of the higher oil and gas prices on Indonesia's economy (namely, higher costs of importing oil offset by higher revenue of gas exports, including fuel-oil-linked pipeline exports to Singapore and crude-oil-linked LNG exports) is difficult to assess. On balance, the burden caused by higher oil prices looks much heavier than the increase in revenue on LNG sales.

Current contractual arrangements for existing ventures in Bontang and Arun

Indonesia's LNG is supplied on mostly long-term contracts, with about 64% going to

Japan, 22% to Korea, and the remaining 14% to Chinese Taipei for the year 2006. Arun contracts are due for completion between 2007 and 2014 while Bontang contracts are due to finish between 2011 and 2018.

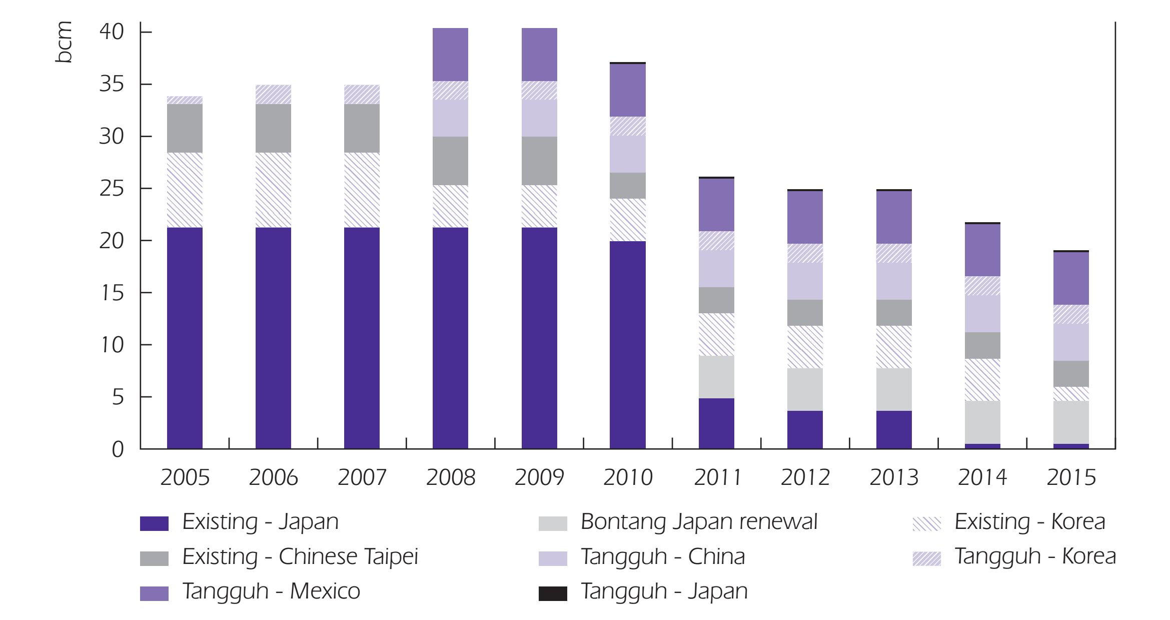
Major contract renewal issues

Until early 2006, Japanese buyers had hoped to renew contracts for half of the 16.3 bcm per year of Indonesian supply contracts set to expire in 2010-2011. This 16.3 bcm represents three quarters of the current total Indonesian contracted volume to Japan and about 20% of Japan's annual LNG imports. The buyers concerned are Kansai Electric, Chubu Electric, Kyushu Electric, Osaka Gas, Toho Gas and Nippon Steel ("Western Buyers" in Japan).

The two sides started discussions on contract renewals in June 2004. An in-principle agreement to extend the contracts was signed in May 2007, after Indonesia's Ministry of Energy and Mineral Resources released its natural gas balance study, which was aimed at evaluating the country's gas balance and determining how much volume will be available for export after its domestic needs are satisfied.

The offered volumes are 4.1 bcm per year for the first five years and 2.7 bcm for the second five years, totalling 34 bcm over the ten-year period, representing less than a quarter of the original deals. The renewal was agreed in March 2008. Volumes to Japan could be increased again if domestic demand does not increase rapidly, as a Pertamina official said in October 2007.

Figure 40 **Commitment of Indonesian LNG supply by existing and planned source and by destination**



Source: Company information.
Note: New projects other than the Tangguh project's first two trains are not included.

Domestic demand should include potential LNG in Java and Sumatra, as well as pipeline gas demand in Kalimantan.

Pertamina announced in December 2006 that it would not extend a 2 bcm per year contract to Chinese Taipei's CPC Corporation when it expires in 2009, 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 that expires in 2017. Subsequently Chinese Taipei cut its 2010 demand forecast for LNG by almost 20%, from 17.7 bcm per year announced in 2005 to 14.3 bcm per year, moving away from its policy of favouring gas to generate electric power in issuing licences to independent power producers after 2007.

Korea Gas Corporation has two long-term purchase contracts from the Bontang plants. One is for 1.4 bcm per year through 2017 and the other is for 2.7 bcm per year until 2014, split between the Arun and Bontang ventures. Another contract from the Arun plant for 3.1 bcm per year expired in 2007, which is being replaced by supply from other sources, including Qatar.

Priority to domestic gas use

Since 2005 Indonesia has been signalling strongly that it will in the future give priority to its domestic market, as it wants to reduce its dependence on expensive imported oil and for the high cost of heavy subsidies to petroleum products consumed in the country. International companies are wary about this position, as domestic gas prices are at least a third less than international prices. Foreign companies are hesitating to develop additional gas 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" and sell 25% of their gas production in the domestic market. The practical enforcement of this law is not particularly clear, nor is the related future policy. The constantly changing gas regulations have discouraged private producing companies from making the development effort needed to reverse declining production. As significant additional reserves are thought to remain around Bontang, these companies will be more active if they get some assurance that the new gas will be available for LNG feedstock.

Indonesia's Energy Minister is apparently seeking more advantageous production-sharing terms at the offshore Mahakam Block when its contract with the operator, Total, expires in 2017; these include a greater share of production for the government, compared to the common 70-30 split. The new framework and its stability will be important in ensuring appropriate investment.

In the natural gas balance study that the Ministry of Energy and Mineral Resources released in May 2007, a large amount of gas was nominally set aside for potential petrochemical use and for gas-fired power generation in the Bontang area. The area's local demand is expected to be 19 bcm per year in 2011 from the current 5 bcm per year, if all the planned and potential industrial and power projects materialise. Also, the study showed potential for "export (LNG)"

Table 38 East Kalimantan gas balance outlook

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Supply (existing + project) [1]	33.89	34.01	34.15	33.83	31.43	25.69	22.59	20.54	21.83
([1] + potential) [2]	33.89	36.89	37.95	37.63	36.45	30.34	27.72	26.81	30.77
Local demand (committed) [3]	5.43	5.80	5.72	5.71	5.67	5.67	5.67	5.67	5.67
([3] + potential) [4]	5.43	5.80	5.72	6.12	19.04	19.04	19.04	19.04	19.04
For LNG already committed [5]	33.11	32.43	32.35	27.88	11.19	9.31	9.29	6.06	4.49
For potential LNG [6]					9.92	9.92	9.92	9.92	9.92
Minimum extra availability	(4.65)	(4.21)	(3.92)	(0.17)	(8.72)	(12.58)	(15.66)	(14.48)	(11.62)
Maximum extra availability	(4.65)	(1.33)	(0.11)	4.05	9.67	5.45	2.85	5.16	10.70

Source: Estimates based on "Gas Balance Study" by Ministry of Energy and Mineral Resources, Indonesia.
Unit: bcm per year. Note: Calculation is made by using a factor of 10.33 bcm per year = 1 bcfd.
Minimum extra availability = [1] - [4] - [5] - [6], Maximum extra availability = [2] - [3] - [5] - [6].

of around 10 bcm from 2011 for the East Kalimantan area. If the above-mentioned potential industrial and power projects do not materialise, further significant volumes could become available from 2010.

On the other hand, the government wants to increase usage of abundant domestic coal, rather than gas in the area (at the same time, the country's energy minister stated the country has no intention of setting a ceiling for coal exports). If the promotion of using more coal instead of gas progresses, gas could be made available for LNG. After Chevron starts production from its deepwater fields (scheduled for 2013), more supplies could also become available. The company's development plan is under review by the Ministry of Energy and Mineral Resources as of April 2008, having been signed off by the country's upstream regulator BPMigas in late 2007.

Meanwhile, a controversial pipeline project linking East Kalimantan to Java appears to have collapsed due to weak economics. Gas-fired power plants in Java are now expected to be supplied from the nearby Cepu block, or from the proposed LNG receiving terminals. This could ease some pressure for feedgas supply to the Bontang LNG plant, which could also supply LNG to the proposed terminals in Java.

CBM potential

Pertamina claims that the country has significant coalbed methane (CBM) resources, particularly in many CBM areas in South Sumatra and Kalimantan. The company estimates its CBM areas may contain about 200 Tcf (5 660 bcm) of gas. Indonesia's Ministry of Energy and Mineral Resources believes that the country could have in total 453 Tcf (13 tcm) of gas at 11 coal basins. South Sumatra and East Kalimantan are major coal-producing provinces. The government could offer investors in CBM projects a better share of profits, compared to the typical 30% in the gas sector.

Concluding remarks

Indonesia will continue to be a key gas supplier in the region with its recent gas discoveries. However, due to the present environment of costlier investment and scarcity of equipment, materials and human capital, future upstream developments may be hindered and may not meet the rising domestic and latent international demand for gas.

The Bontang area retains significant potential; upstream developers are positive if conditions supportive of necessary investment can be agreed with government. This means that more LNG could be produced for both the domestic and export markets. The practice of "reserving" portions of future gas supplies for national use (presumably at low prices) is especially counterproductive. In common with many other producing countries, subsidised gas prices are discouraging efficient gas use.

Myanmar

Myanmar is an agricultural country rich with natural resources such as oil, gas, precious stones, timber and various metals. Oil and gas attract the largest share of foreign investment in Myanmar and it has potentially large gas resources, particularly in offshore areas. The Yetagun and Yadana fields account for half of Myanmar's recoverable reserves. Around 90% (12 bcm per year) of the output from these two fields is exported to Thailand. Myanmar's gas exports account for 30% of Thailand's consumption, via pipelines. Myanmar and Thailand have started negotiation on block M-9 in the Gulf of Martaban for additional gas export to Thailand. This supply has enabled a significant reduction in oil use in Thailand's power sector.

Consumption in Myanmar's domestic sector is limited due to insufficient domestic gas infrastructure and the availability of hydro-electric power.

Late in 2007, China won the rights to buy gas from Myanmar's biggest fields; blocks A-1 and A-3. The A1 and A-3 blocks were certified to hold recoverable reserves as much as 218 bcm of gas. The blocks are operated by Deawoo International of Korea. The gas is expected to be transported to the Yunnan province in China, via pipeline.

Papua New Guinea

Papua New Guinea is richly endowed with oil and gas resources but currently exports only oil. In recent years, significant amounts of gas were discovered while exploring for oil. Current market conditions of increasing gas demand within, and outside of, the region present Papua New Guinea with the opportunity to diversify its market and the country hopes to export its first LNG cargo as early as 2013.

Meanwhile, PNG LNG is finalising with the Papua New Guinea government the terms on potential gas prospects in Hides, Juha and Angore fields. PNG LNG is ready to mobilise its team to enter into the front end engineering and design (FEED) stage once the discussion with the government is concluded.

Conclusion on Southeast Asia

The producing countries' search for new gas fields continues in order to compensate for declining production. The challenge for gas producers in the Southeast Asia region is to intensify exploration and development efforts or face the prospect of greater reliance on supplies from other regions in the future. Suitable mechanisms to resolve disputes between countries, as well as clearer framework for investment and pricing mechanism are needed to facilitate monetisation of further resources.

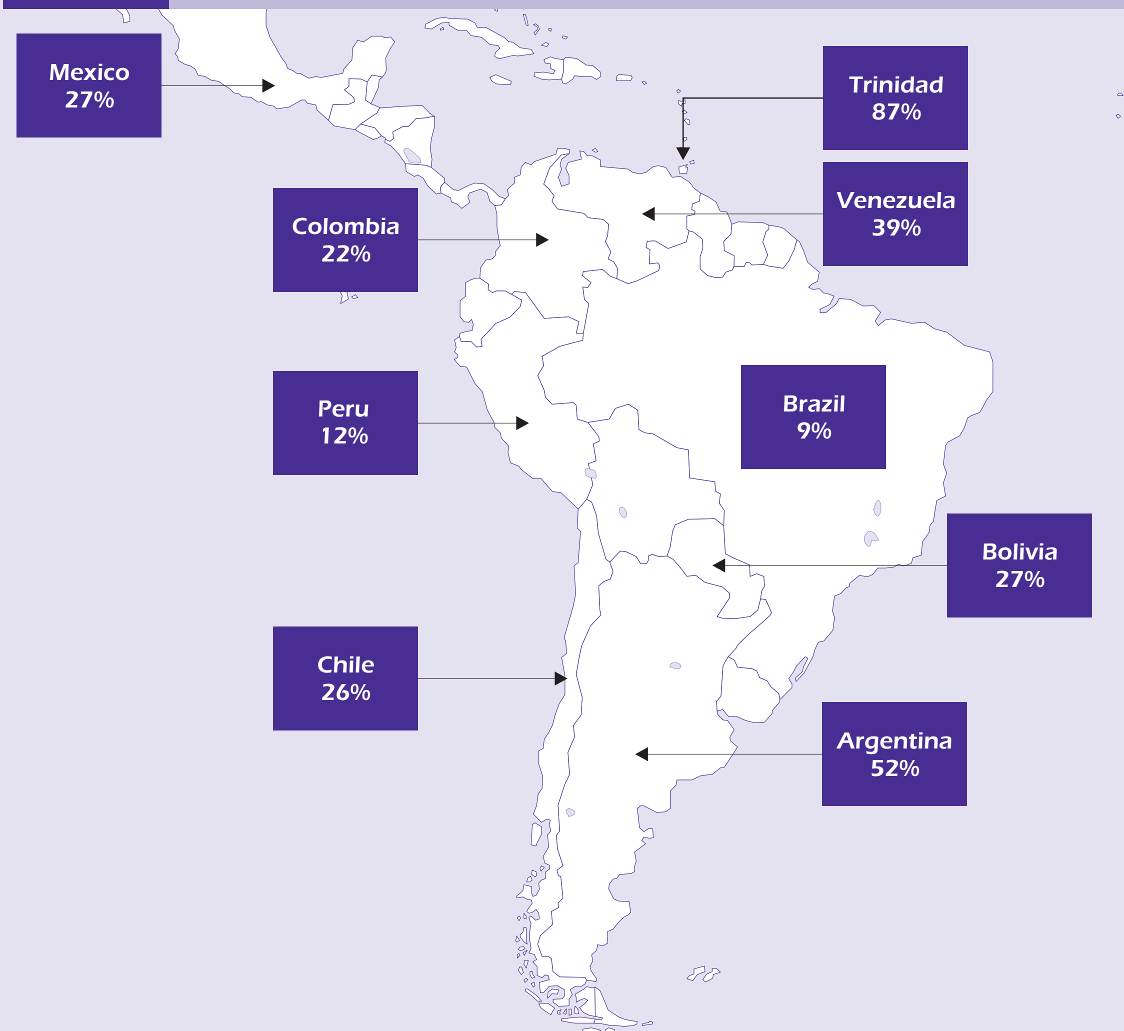
Latin/South America

In 2007, natural gas represented 21% of total primary energy supply in South America. The region produced 145 bcm of gas and consumed 130 bcm, of which 32.5 bcm were used to produce electricity. Gas production and consumption in South America – excluding Trinidad and Tobago – remain highly concentrated. Five countries – Argentina, Bolivia, Brazil, Colombia and Venezuela – account for 95% of gas production. Argentina, Brazil, Chile, Colombia and Venezuela represent 94% of total gas consumption.

Recently there has been a consolidation of the recent trend towards the integration of South America into the emerging global gas market, and away from regional integration that drove the expansion of cross-border gas trade in the last decade. The paradox of gas dynamics in South America is such that although the region has substantial gas reserves, the recent surge in resource nationalism (Bolivia and Venezuela) and unsound economic policies (Argentina) in the main gas-supplying countries have led gas consuming countries to turn to shipborne LNG from outside the region as a more reliable source of supply than overland pipeline imports from neighbouring countries. Revealingly, the only country in the region developing an LNG export project other than Trinidad and Tobago, Peru, is not planning to supply other countries in the region, but will send three quarters of its output to Mexico, with shipments due to start in 2010. A confirmation of this trend has seen several pipeline projects abandoned in the last few years, including the grand pipeline of the South once proposed to connect Venezuela to Brazil, Argentina and Chile; a line from Peru to supply Southern Cone countries, a doubling of the Gasbol pipeline capacity between Bolivia and Brazil, and new lines to Paraguay and Uruguay. Venezuela has significant gas reserves (approximately 4 300 bcm) and although LNG exports have been stalled for over 10 years, in the longer term the country could become an important LNG player.

In a region where gas shortages have become endemic (Argentina, Brazil, Chile, and Uruguay), the shift towards LNG is chiefly motivated by energy security and geopolitical concerns, as cross-border gas trade is increasingly perceived as highly dependent on local politics. This transition will also bring about profound changes in the energy value chain throughout the region. Today, several LNG receiving terminals are either being built or at the planning stage – two, possibly three, in Brazil, two in Chile, one in Argentina and one in Uruguay. If all are built, South America could be importing 13.6 bcm per year of LNG by the end of the decade, reaching 27 bcm by end 2012.

Map 10 **Share of gas in total primary energy supply in Central and South America and Mexico**



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.

With this volume, the region would remain a niche from the perspective of the global LNG market, but South American countries will become more exposed to international price levels.

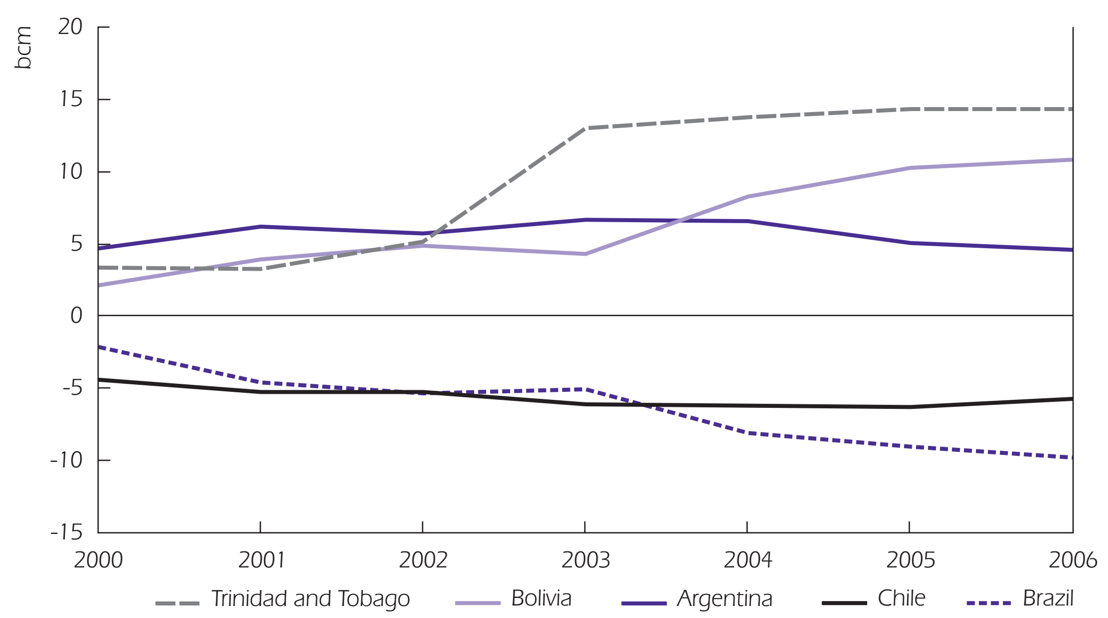
Argentina

The gas shortages that started in 2004 in Argentina are becoming even more pronounced, particularly during hot summers or cold winters. Residential tariffs remain frozen at 2001 prices, thereby creating a strong disincentive to save energy and encouraging rapid demand growth. These artificially low prices have further hampered investment in new production capacity and new transmission facilities. While Argentina pays USD 7 per MBtu for natural gas from

Bolivia, producers within the country are limited by government-mandated prices of just USD 1.4 per MBtu, which has unsurprisingly deterred domestic investment. Faced with the threat of dramatic shortages in the southern hemisphere winter 2008 (from June to September), the Argentinean government is seeking ways of boosting supply. In this perspective, the Gas Plus plan, announced in March 2008, will allow domestic natural gas production from new fields to be sold at higher prices than existing output. However, the price allowances are worded in such a subjective way that producers are concerned about the possibility of further government price interference at a later point.

Possible gas shortages in winter 2008, when the government-sponsored gas rationing program started, could be the most severe since 2004 and could reach an estimated 40 mcm per day or 28% of Argentina's production of 140 mcm per day. Gas shortages in Argentina are especially painful because gas represents approximately 51% of the country's total primary energy supply. The country thought it had resolved its energy supply problem when it signed a 20-year agreement in October 2006 to purchase increasingly larger amounts of Bolivian gas, but the Bolivian government admitted in late 2007 that it would not be able to meet the ambitious delivery schedule because of a lack of investment to develop its gas fields. Hence, it is understandable

Figure 41 **Export trends in South America**



Source: IEA.

that Argentina would be reluctant to invest USD 1 billion, in a 1 470 km pipeline linking Bolivia's southern gas fields to Argentina's northern provinces that may lie dormant given Bolivia's inability to boost production. As a result, the pipeline tender process has been on hold since July 2007. A further complication is the mounting opposition from five eastern Bolivian departments – among which Santa Cruz and Tarija, the source of 90% of Bolivia's gas and where the majority of the country's gas reserves are located – heightening political uncertainty for gas developers in the country (Petrobras, Repsol YPF, Total and BG). Bolivia's difficulties in increasing production and its preference to the Brazilian market have led the government of President Cristina Fernández de Kirchner to look for other solutions.

A short-term solution is to rent a dockside terminal, using onboard regasification vessels to regasify 5-8 mcm per day of LNG in Bahía Blanca port, 687 km southwest of Buenos Aires, for the southern hemisphere winter 2008. Argentine state energy company Enarsa has rented the vessel from Repsol YPF to supply petrochemical companies and the national grid. The project avoids the issue of subsidised gas prices as the LNG is intended for industrial users. However, such terminal can only be a temporary solution until domestic gas production increases and/or another permanent LNG terminal is completed. Such infrastructure could be part of a joint project between Enarsa and state-owned Petroleos de Venezuela (PDVSA). The two companies published newspaper advertisements at the beginning of April 2008 calling for expressions of interest in building the plant, but with few details. The permanent terminal would be located in the Bahía Blanca petrochemical centre. The regasified LNG would be used mainly for electricity generation by Petrofertil, a fertiliser manufacturer partly owned by Repsol YPF.

In addition, Transportadora de Gas del Sur (TGS), the largest operator of natural gas pipelines in southern Argentina indirectly controlled by Petrobras, has recently called for expressions of interest for a project to build an underwater pipeline. The Cruce Boca Oriental pipeline, as it has been dubbed, will increase total transport capacity between Tierra del Fuego, an archipelago with gas fields in production and development, and the mainland Santa Cruz province, to 22 mcm per day from the current 9.5 mcm. The government wants the pipeline in operation before the southern hemisphere winter of 2009. Tierra del Fuego produces 11-13 mcm per day, or nearly 9% of the national average production of 140 mcm per day while TGS carries approximately 60% of Argentina's total gas flows.

Increased production in Argentina will come only slowly as President Cristina Fernández de Kirchner will seek to limit every price increase in an effort to keep rising inflation under control and avoid further social unrest. Major companies like Repsol YPF, Petrobras and Pan American Energy will likely wait until further price increases and credible incentives are given to the private sector before substantially expanding investments. As a result, domestic production is not likely to rise significantly until the next decade.

Bolivia

According to government data, Bolivia's export commitments will require upstream investment of USD 3.51 billion by 2012. This is equivalent to the total investments made during the 1994-2006 period but this time to be mobilised in 5 years instead of 12, and after investors' confidence has reached very low levels. Due to the lack of investment, production is currently stagnant at around 40 mcm per day, while 2007 contractual demand was around 48.5 mcm per day. Shipments to Cuba in Brazil have been cut and supply to Argentina is about 3-4 mcm per day. The situation will get worse as the export commitment to Argentina is scheduled to ramp up from 7.7 mcm per day to 16 mcm per day and then to 27.7 mcm per day in 2010.

On 1 May 2008, the government of Bolivian President Evo Morales completed formal implementation of its two year-old decree to nationalise the country's hydrocarbons sector, with national oil company YPFB acquiring a controlling stake in four energy companies that were partially privatised during the 1990s. YPFB purchased majority ownership (50% plus one share) of Andina, Chaco, pipeline firm Transredes and CLHB, which was in charge of YPFB's former storage operations. Andina was previously controlled by Spain's Repsol YPF; Chaco by both BP Plc and Pan American Energy; Transredes by Ashmore Energy International Ltd; and CLHB by Germany's Oil Tanking and Peru's Graña Montero.

The original intent of the 2006 nationalisation decree was to establish a strong vertically integrated YPFB with a growing presence in the processing of hydrocarbons and their use for the industrialisation of the country. However, instead of leading to state control over hydrocarbons reserves, the nationalisation process simply resulted in the Bolivian government earning a higher income. The new tax regime establishes a government share of up to 65% of gross sales for small fields and over 75% for larger fields. Royalties of 50% in Bolivia are five times those of Brazil. These tax levels combined with political uncertainty are discouraging new investments, making it harder for Bolivia to increase its output, which is a key prerequisite in order to diversify its export destinations and products. In fact, these developments, designed to diversify export destinations, have had the exact opposite effect of maintaining the country's dependence on Brazil for export revenues.

The Bolivian government is keen to use pricing developments in the region, such as the price Chile is willing to pay for LNG imports, as a bargaining tool in export price negotiations with Brazil, arguing that the price at which it sells to Argentina should be relative to the price Chile pays for LNG. However, as long as the country remains dependent on a single large-scale export destination, its influence over prices will be limited. Gas is of such importance to the Bolivian economy that failure to meet the country's new export commitments would not only jeopardise its industrial development plans, but would also have significant and destabilising fiscal impacts. The Bolivian government is therefore trying to find a way to stimulate new investments. Greater autonomy from central government of the Santa Cruz department, resulting from the May 4, 2008 referendum, will further complicate the situation, as gas rich departments may seek to negotiate their own royalty deals with oil and gas companies.

Chile

Chile epitomises energy security concerns in South America. Over 30% of the electricity generated in the country currently depends on gas imports from Argentina, but since 2004, the country has faced increasing cuts from its neighbour. Chile's two main power grid systems, the Central system (SIC) and the Northern system (SING), depend entirely on Argentina for their gas supply. Domestic production is limited and is located in the far south, more than 3 000 km from the capital, Santiago, and main demand centres in the Central/Southern system. The current energy crisis follows the combination of Argentinean gas cuts of almost 95% in Q2 2008 (from contracted levels of 8 bcm per year), slow investment in capacity expansion, a particularly poor hydrological year in 2007, and generator Colbún's decision to take the 368 MW Nehuenco 1 plant offline for nine months following a fire at the plant. Although the Argentinean government recently promised to maintain minimum levels of gas exports to supply the residential and commercial sector in the Central system during the winter months, export restrictions will have an economic cost for Chile as they have caused shutdowns at power plants and forced consumers to switch to costlier fuels such as diesel. These costs have reduced profit margins and brought some companies to the brink of bankruptcy, especially in the Northern grid where the mining sector typically accounts for 90% of demand. Along with the cuts in volumes, Argentina has also increased natural gas prices: in March 2008, it increased its natural gas export tax to Chile by almost 100%, with the price of gas exports reaching USD 20 per MBtu. Gas cuts from Argentina also have environmental costs. Because power plants of the Central grid, where Santiago and industrial centres are located, have had to switch to diesel and coal, Santiago has recently experienced some of its highest levels of air pollution in over 15 years.

In response to gas cuts from Argentina, Chile has launched a two-pronged strategy to diversify both its sources of gas (through LNG imports) and its energy mix (through other sources of energy such as coal and hydro).

In 2006, ENAP (Chile's state-owned energy company), in partnership with BG Group, announced the construction of South America's then first LNG receiving terminal in Quintero, 114 km from the capital Santiago, to supply the densely populated central region where over 90% of the population lives. Looming gas and energy supply problems gave the government little alternative but to pursue the fast-track construction option in a seismically sensitive country, which increased costs to USD 1 billion. Two companies were created: GNL Quintero is responsible for building and operating the regasification terminal, and GNL Chile (40% owned by BG and 60% shared equally among three Chilean entities Enersis (60.62% owned by Endesa), Metrogas and ENAP) buys the LNG and sells natural gas. In 2006, GNL Chile signed a 20-year supply agreement with BG Group, which should supply 3.4 bcm per year, equivalent to 40% of Chile's natural gas demand. However, given limited alternative gas supply options in the short term, this volume could easily increase, as the regasification plant is being constructed with a view to possible expansion to 7 bcm per year. While this project should ensure that some generating plants will be able to operate on lower-cost and more efficient gas, it will not increase generating capacity significantly, merely offsetting the deficit of Argentinean gas.

The second LNG project, located in Chile's northern system (SING), is an urgent priority for the mining sector. The Mejillones terminal is a 50/50 joint venture company between Suez Energy and state-owned mining giant Codelco, the world's largest copper producer, and at an investment of USD 500 million will supply 1.8 bcm per year to four existing power plants totalling 1 100 MW. Construction started in March 2008 and the first stage of the project should be ready by early 2010 using an LNG vessel for storage, as well as a jetty and onshore regasification plant, until permanent storage facilities are built (still not confirmed) by 2012. The main off-takers of the project are the mining companies BHP Billiton, Collahuasi, El Abra and Codelco Norte who have signed a three-year sale and purchase contract from 2010.

The opportunity cost of LNG relative to other sources of power will be critical for the development of Chilean LNG imports. Chilean gas consumers may agree to pay a premium for supply security, given the risk involved in Argentine gas imports. However, as much of the gas is used in power generation, LNG will need to be competitive with other fuel sources such as coal in particular.

It would seem logical for Chile to import LNG from its next door neighbour Peru given the proximity of its Mejillones regasification terminal and its critical need for LNG supplies, but a long-standing border dispute that goes back to the late 19^{th} century between Chile and Peru is making it extremely difficult for the two countries to seize this opportunity. Even though relations between the two countries have improved since the election of Alan García in Peru and Michelle Bachelet in Chile, mainly fuelled by the huge amount of commercial exchange between both countries, there remains a disputed maritime border between the two nations and President García has taken the matter up with the International Court of Justice in 2007. Therefore, relations remain fragile, but could evolve if given sufficient diplomatic priority by both countries.

Bolivia and Chile, who share a border, have had strained relations ever since independence in the early 19th century because of a border dispute, which in 2003 caused the Bolivian government to withdraw a proposed LNG project on the coast of Chile. The project would have exported gas from landlocked Bolivia's huge Margarita reserves to the United States via Chile's northern port. However, Bolivians categorically refused to allow Chile to use some of the natural gas. This resentment was further illustrated in 2004, when Bolivia, contracting a gas agreement with Argentina, insisted that "not a molecule" could be resold to Chile.

Nationalist posturing has been one of the most outstanding obstacles to energy integration in South America, despite the tremendous potential economic benefits at stake.

Brazil

In recent years, Brazilian natural gas demand has been growing faster than domestic supply additions. In 2006, 40% of the country's gas supply came from neighbouring Bolivia. However, Bolivia's political instability and the nationalisation process have deterred Brazil from increasing pipeline import capacity. Brazil has two independent gas systems. The Northeast system uses mostly domestic natural gas while the Southeast-South-Midwest system links domestic supply to the Bolivian and Argentinean gas networks, with Bolivian gas accounting for approximately 75% of the total. In the short to medium term, Brazilian natural gas demand is expected to expand to nearly 50 bcm in 2012 from 21 bcm in 2006. The country aims to meet some 55% of this demand from domestic production with the balance split equally between Bolivian and LNG imports.

In order to meet fast growing domestic demand, the Brazilian government has launched a two-pronged strategy. First, Petrobras is accelerating development of domestic gas production. The company's 2008-2012 business plan calls for an increase in domestic production of 9 bcm per year by 2012, equivalent to 50% over the 2006 level of 18 bcm. Most of this increase will come from the Southeast and in particular from the Espírito Santo and Santos Basins. Second, the company is developing with urgent priority two LNG import terminals using regasification vessels in the North and in the South of the country. Petrobras is initially seeking 2 bcm per year at Pecém, Ceará, in the Northeast by as early as July 2008 and 4.8 bcm per year for Guanabara Bay in south near Rio de Janeiro in 2009. The company intends to use LNG in the country's dry season to compensate for lower output of hydro power and avoid months of higher LNG demand in other markets in the world. In March 2008, Petrobras announced a three-year LNG purchase agreement with Shell without disclosing volumes and other terms. In addition to another LNG purchase agreement that the company claims to have signed in December 2007, it has also signed master spot purchase agreements with Nigeria LNG, Algeria's Sonatrach, France's Suez, and Spain's Endesa. It has also agreed to buy LNG from BG.

The Pecém terminal will be the first floating storage and regasification unit (FSRU) LNG terminal in the world while the Guanabara Bay terminal will employ a shuttle and regasification vessel (SRV). These different technology options aim to match the two terminals' expected demand patterns. In the northeast, where gas shortages have become endemic, LNG supply will be used for base load power generation as well as for peak demand. In the southeast, where power demand has grown more rapidly than in the north, the dispatch of gas-fired plants is expected to increase, with LNG supply expected to meet peak load demand of shorter duration. Petrobras is also considering building a third terminal in the south of Brazil and has announced plans to have 11 bcm per year of regasification capacity by 2012. Future imports by the country are highly dependent on how fast Petrobras is able to develop two recent major hydrocarbon resource finds in the offshore Santos Basin: Tupi and Jupiter, which could be feedgas sources for potential LNG production in the country.

With regards to the stability of Bolivian gas supply, Brazil is likely to stay ahead of Argentina on the list of Bolivian export priorities. Bolivia recently chose to cut gas flows to Argentina in order to meet Brazil's request for increased exports under their gas supply agreement. In exchange for such contract flexibility, Bolivia expects Brazil to deliver on its investment promise of USD 1 billion in the next five years in order to boost gas output, which is currently too low to meet export commitments to Brazil and Argentina, as well as rising domestic demand. If Petrobras delivers on its investment promise, it is likely to focus on upstream, with little consideration for the expansion of the 11 bcm per year Gasbol pipeline that connects the two countries as planned before the May 2006 nationalisation. Some analysts have advanced that with relatively low investments in compression, capacity could be increased by 10-15%.

Peru

Peru has a relatively large natural gas reserve base of 250 bcm – although modest in comparison Venezuela's 4 300 bcm in 2006 – and a small domestic market of 2.2 bcm per year in 2006. Although domestic demand is set to increase significantly over the next decade, there are still substantial surplus reserves that could be exported. Peru LNG, formed by a consortium led by Hunt Oil, SK Energy, Repsol YPF and Marubeni, will develop, construct and operate the first LNG plant on the Pacific Coast of the Western Hemisphere, and a new 408 km natural gas pipeline that will connect the LNG plant to the existing Transportadora de Gas del Perú natural gas pipeline (TGP) at the end of TGP's segment, which runs from the Camisea gas fields through the rainforest. Peru LNG will sell the total LNG output to Repsol YPF, who, in turn, will export it primarily to Mexico. First LNG cargoes are expected to be available in late 2010. While Repsol YPF has committed about 75% of the plant's total output of 6 bcm per year of LNG to the planned Manzanillo terminal in western Mexico under a 20-year supply contract, substantial supply could also be available for potential sale to the west coast of North America and Asian markets in the Pacific Basin.

The Peruvian government has been promoting the use of gas as a replacement for more expensive imported petroleum products in the petrochemical and industrial sectors, in power generation, and for vehicular and domestic use. Relatively low domestic gas prices and high economic growth rates of around 8% in recent years have helped fuel a 51% increase in domestic gas consumption from 2006 to 2007, with natural gas representing close to 18% of total primary energy consumption in 2007. In this context, some criticism has emerged within the ranks of Peru's oil industry, claiming the country's natural gas should be reserved for domestic consumption instead of exports. The recent discovery of some 57 bcm by a Repsol YPF-led consortium in January 2008 should ensure sufficient supply for the growing domestic market to run in parallel with the export project and even its possible expansion.

Uruguay

Uruguay is also facing energy shortages as a result of low rainfall combined with dwindling Argentine gas imports. The government is confident that minimum levels of imports from Argentina will continue despite the latter's obvious problems, justifying this confidence on the fact that Uruguay is only a small client consuming around 0.11 bcm per year of gas compared with Argentina's 45 bcm per year. But the price of imports from Argentina is likely to increase on the back of a tax increase on natural gas exports to Chile that could mean a 30% rise in Uruguayan electricity bills. Since 1998, Uruguay, which does not have any natural gas resources, has relied on Argentina for gas supplies through two pipelines. In 2004, however, Argentina began restricting gas exports and redirecting the supply to feed its domestic market as shortages threatened to slow the economy. Argentina has therefore become a less reliable supplier for Uruguay, prompting the national oil company, Ancap, to look for new sources of gas.

Against this backdrop, Uruguay's recent call for expressions of interest, in collaboration with Argentina, to build a 9 bcm per year LNG onshore regasification terminal near Montevideo attracted many companies. These included Petrobras, Repsol YPF, BG and Pan-American Energy (owned by BP (60%) and BRIDAS of Argentina (40%)). The joint project between Argentina's Enarsa and Uruguayan counterpart Ancap is estimated to cost between USD 1.5 - 2.5 billion and is slated to start up in 2012-2013 with 10 mcm per day (3.65 bcm per year) of capacity and later expand to the full amount. The countries will share the gas evenly. With average gas consumption totalling 0.3 - 0.4 mcm per day, the proposed terminal would allow Uruguay to use gas as a substitute for generating electricity at fossil-fuel powered plants, easing demand for imported gasoil and fuel oil. A previous possibility was to join a project to build a proposed 8 000 km South American pipeline that would take Venezuelan gas to the region. But the estimated USD 25 billion project is now shelved as the region is turning to LNG, believed to be cheaper over long distances, more reliable given the uncertain political climate in some countries, and less damaging to the environment.

Concluding remarks

The overriding factors driving South America's LNG development are energy security and geopolitics. The extent to which it will become a permanent feature of the region's energy future will depend on the price and terms of LNG purchases, the regional and global availability of natural gas, the competitiveness of alternative fuels, and the prevailing political realities regarding regional integration. In the meantime, South American countries are developing LNG projects with different motivations. LNG imports are an expensive, stopgap measure for Chile and Uruguay, a symptom of underinvestment for Argentina and a temporary necessity for Brazil. For all four countries, importing LNG is the best short-term strategy to deal with natural gas shortages, as it allows them to secure gas from the global market and not tie themselves to supplies from one particular country.

Map 11 South American gas 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: Petroleum Economist and IEA.

However, LNG's advantages in terms of energy security and flexibility also come at a cost, especially in a region which is still a niche market. LNG imports are bound to progressively cut into South America's isolation from global pricing trends and in the medium to long term will increase the competitiveness of domestic gas production. All countries will need adequate pricing mechanisms to pass higher costs on to consumers, at the risk of jeopardising regasification projects. In the longer term, LNG may provide a more flexible, less politically charged option than overland pipeline projects with Brazil and Venezuela as potential LNG exporters, and a more diverse supply portfolio for the region's importers.

West Africa

West Africa is emerging as an important natural gas provider in the world market. Since their local gas markets are under-developed, however, a large portion of their gas output is processed into LNG for export. Nigeria is a leading producer, exporting 23 bcm of LNG in 2007, accounting for 10% of the world LNG trade. Equatorial Guinea completed the construction of its first LNG production facility and delivered the first cargo in May 2007. The first Angolan LNG project received a final investment decision (FID) in December 2007 and the first production is expected in 2012.

Nigeria

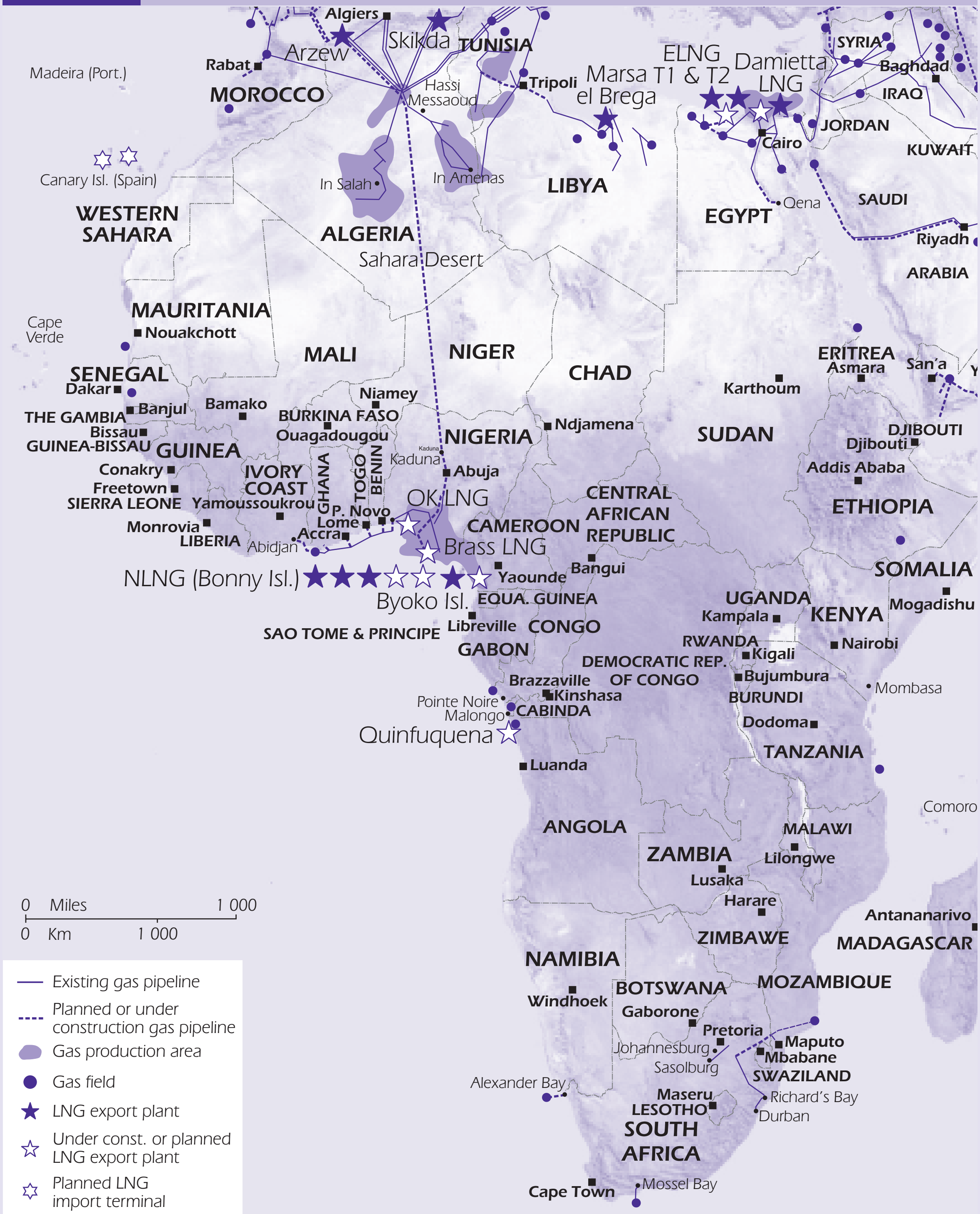
Nigeria has an estimated 5 tcm of proven natural gas reserves, which makes the country the seventh-largest natural gas reserve holder in the world and the largest in Africa, bigger than Algeria. In 2006, Nigeria produced 28.5 bcm of natural gas, of which 17.1 bcm is LNG. The remainder was used domestically for power generation, industry and oil extraction, with the absence of distribution system for most residential customers.

The Nigeria LNG (NLNG) project, located in Bonny Island in the Niger Delta, with the launch of Train 6 in December 2007, has total LNG production capacity of 30 bcm per year, overtaking Algeria and becoming the largest LNG production capacity holder in the Atlantic basin. Nigerian LNG was exported to mainly Spain (10 bcm), France (4.1 bcm), Portugal (2.7 bcm) and the United States (2.7 bcm) in 2007, while 2 bcm was exported to Asia-Pacific region importers.

NLNG is investigating the possibility of adding huge seventh and eighth trains of 10.9 bcm per year each, though an FID is yet to be made. The partners of NLNG include Nigeria National Petroleum Corporation (NNPC, 49%), Shell (25.6%), Total (15%) and Eni (10.4%). Despite the ongoing insurgency in the Niger Delta region, the NLNG facility has not been seriously attacked by rebel groups, probably because it is one large complex, instead of many small isolated flow-stations as with oil, and has better security.

Companies have proposed additional LNG projects such as Brass LNG (ConocoPhillips, Eni, Total and NNPC) and Olokola LNG (Chevron, Shell, BG and NNPC). Brass LNG partners awarded the United States firm Bechtel the front-end engineering and design (FEED) contract in November 2004 and the construction contract in June 2007. There has been little progress

Map 12 African gas 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: Petroleum Economist and IEA.

in Olokola LNG after the memorandum of understanding was signed between the partners in July 2006. The FIDs of both projects have been delayed due to increasing costs, disagreement on fiscal terms between shareholders, and security concerns in the Niger Delta.

Nigeria has also developed projects to export natural gas via pipelines. The West Africa Gas Pipeline (WAGP) project, led by Chevron and partly funded by the World Bank, will carry natural gas from Nigeria to Benin, Togo and Ghana. The 678 km WAGP was commissioned in December 2007 while the commercial operation is expected in mid-2008, delayed by more than one year from the original target date at the time of construction decision.

Although the idea for the pipeline was conceived more than 20 years ago, it was not until 1995 that a concrete plan emerged, followed by a decision to build it in December 2004. The shareholders are the project operator Chevron (38%); NNPC (25%); Shell (17%), and Ghana's Takoradi Power Company (16%); Togo's Société Togolaise de Gaz (2%) and Benin's Société Beninoise de Gaz S.A. (2%).

In addition to reducing gas flaring in the Niger Delta region, Ghana will also significantly benefit from the project as it can reduce spending on diesel for power generation. The initial capacity is 2.1 bcm per year and the pipeline is expected to reach full capacity of 4.6 bcm per year within 15 years.

Nigeria is in talks with Equatorial Guinea on the construction of a pipeline connecting the two countries to feed Equatorial Guinea's second LNG train with Nigeria's gas.

Nigeria has also discussed with Algeria and Niger the construction of Trans-Saharan Gas Pipeline (TSGP) that would then be connected further to the European market.

Table 39 West Africa's major gas related projects

Project name	Shareholders	Capacity (bcm per year)	Status
NLNG	NNPC, Shell, Total, Eni	30	Train 6 launched in December 2007. Trains 7 and 8 are planned.
Brass LNG	NNPC, ConocoPhillips, Eni, Total	13.6 (planned)	FEED contract awarded in 2004 and construction contractor was selected in 2007
Olokola LNG	NNPC, Chevron, Shell, BG	15 (planned)	MOU signed between partners in 2006
WAGP	Chevron, NNPC, Shell, Ghana's power company, Togo and Benin's gas companies (partly funded by World Bank)	Initial capacity 2.1; Full capacity 4.6	Commissioned in December 2007, commercial operation in mid- 2008
EG LNG	Marathon, Sonagas, Mitsui, Marubeni	4.6	The first cargo shipped out in May 2007. The second train is proposed.
Angola LNG	Chevron, Sonangol, BP, Eni, Total	7.1	FID in December 2007, production in 2012

Source: Company announcements.

The pipeline would carry 20-30 bcm per year, 4 200 km from the Niger Delta through Niger and Algeria to the Mediterranean Sea. Though this project is still at the planning stage, Nigeria and Algeria launched a promotion campaign for this pipeline to European countries in July 2007. The Nigerian Minister of State for Gas said in March 2008 that around 400 bcm of reserves had been set aside for the project. The projected start-up date is 2015.

Chevron and NNPC signed a joint venture gas supply agreement for the Escravos gas-to-liquids (GTL) project in 2001, targeting 2005 production start. The project would process some 3 bcm per year of natural gas into 34 000 barrels per day of clean liquid products with Chevron and NNPC holding 75% and 25% stakes, respectively. South Africa's Sasol provides the technology through a joint venture with Chevron. While the project is running behind its original schedule and start-up looks unlikely before 2010, processing modules are being constructed in the United Arab Emirates.

In February 2008, Nigeria announced its new gas policy which will prioritise the domestic use of gas over export. Under the policy, all gas developers are expected to allocate a specified amount of gas from their reserves and annual production to the domestic market, and gas for domestic use would be supplied at the lowest commercially sustainable prices to strategic sectors such as electricity. Nigerian government plans to build 15 new gas-fired power plants and to increase generating capacity to 10 000 MW by 2010.

According to OPEC data, 22 bcm of gas was flared in Nigeria in 2006 in addition to LNG production and domestic consumption. The Nigerian government set a target of ending gas flaring by the end of 2008 and announced oil companies which continue to flare gas after the deadline would be heavily fined. Though the deadline could be unrealistic, utilising flared gas would help increase the amount of gas for domestic use as well as export.

It is reported in January 2008 that Gazprom is in talks with Nigerian officials on potential gas investments worth USD 1-2.5 billion in Nigeria. Although there are few details revealed, this move is possibly aimed at Gazprom's engagement in Nigerian LNG projects.

Equatorial Guinea

While Equatorial Guinea has only 110 bcm of proven natural gas reserves as of end 2007, its marketed gas production (excluding reinjection and flaring) has increased rapidly from 0.03 bcm in 2001 to 1.3 bcm in 2006. The gas production is centred on Marathon's Alba field, offshore Bioko Island. Throughout the 1990s, the main gas-related production was condensate and LPG while most associated gas was flared and non-associated gas was re-injected.

Marathon leads the country's first LNG project (EGLNG) and owns a 60% stake in the first train of the project. The other partners are the national gas company Sociedad Nacional de Gas de Guinea Ecuatorial (Sonagas, 25%), and Japanese companies Mitsui (8.5%) and Marubeni (6.5%). The first cargo was shipped out in May 2007, six months ahead of schedule.

The partners of EGLNG's first train have a 17-year deal to supply BG with 4.6 bcm per year of LNG. While the default destination is the United States, the company has flexibility in determining delivery destinations. In fact, more than half of the 0.9 bcm production in 2007 was sent to the Asia-Pacific markets.

The rapid completion of the first train has given Marathon the confidence to plan a second LNG train. To feed the second train, the country would need to get natural gas from neighbouring countries. Preliminary agreements have been made with both Nigeria and Cameroon in this regard. The partners of the second train include the partners of the first train as well as Germany's E.ON and Spain's Union Fenosa Gas.

Angola

Angola has 270 bcm of proven natural gas reserves as of end 2006, and produced only 1.0 bcm of natural gas in 2007, which is lagging behind even Mozambique and Côte d'Ivoire. Angola flared 8.2 bcm of natural gas in 2006 according to OPEC, which is the second-largest amount in Africa after Nigeria. The Angolan government has declared that flaring should be eliminated by 2010. The gas which is not flared is re-injected into oil fields to aid recovery, used as a fuel for oil operations, and processed in the production of LPG.

Angola's domestic gas market has not been developed due to various reasons; there are no large customers to justify initial investment in infrastructure which was almost nil due to a long civil war; relatively small amount of gas production from each field means it would cost a lot to build transportation and gas-gathering facilities; and the country has so far been lacking a clear gas development strategy and regulatory framework to encourage development of the sector.

Given the current lack of local gas markets, LNG export was clearly the main option to make use of gas reserves. Chevron (36.4%) and the state oil company Sociedade Nacional de Combustíveis de Angola (Sonangol, 22.8%) are leading the development of the country's first LNG project (Angola LNG or ALNG), which will convert both associated and non-associated gas from several offshore fields for export. The other partners of ALNG are BP, Eni and Total (13.6% each). ALNG has received a final investment decision from shareholders in December 2007. This project will start off as one plant capable of 7.1 bcm per year, and the first LNG production is expected in early 2012. ALNG also has a plan to process and treat up to 3.5 mcm per day of gas for the domestic market. The process of developing a second train is already underway. When Eni joined the first train consortium in 2006, it signed a participation agreement to join a second train consortium, which would be led by Sonangol (40%).

GAS SECURITY

IEA member countries are entering a period of depleting domestic energy resources and growing reliance on gas imports from increasingly distant producing centres. Gas becomes more expensive and huge investment is required in import, interconnection and flexibility infrastructure. The impact of previous supply disruptions on regional markets have provided us with a number of case studies of the consequences of larger and more sustained disruptions.

Well functioning markets are essential to provide reliable, affordable and efficient natural gas supplies. However, external shocks may disrupt the normal market functioning and pre-empt market failure. Therefore, security mechanisms beyond those provided by the market must be considered in order to mitigate in an efficient and timely manner the consequences of a supply disruption.

There are emergency measures responses in the oil industry within IEA member countries, and a mechanism for co-ordinated actions by IEA member countries. However, there are no such mechanisms for natural gas. IEA Ministers have already observed that global energy security issues include gas, electricity and other energy sources. Furthermore, Ministers called on the IEA to report on the range of measures available to improve gas security, as well as to advise on emergency response mechanisms and policies for gas markets and their potential international implications. This work is underway and should be completed over the course of 2008 and 2009.

Member country provisions

The following section examines briefly existing security of supply policies and measures in place in several member countries. The policies of each have evolved as a response to the local market circumstances. In the case of Spain, its mechanisms draw on the fact that almost all of its gas consumption is imported, mainly in the form of LNG, and also on the lack of available storage capacity. Poland relies on pipeline imports for much of its gas consumption (although gas represents a small part of TPES). Being conscious of a growing reliance on only one country for gas, Poland has recognised the need to diversify its sources of gas. The United Kingdom is one of Europe's largest consumers of natural gas and was until recently self-sufficient. Its rapidly increasing reliance on imports brings challenges in relation to timely investment in a range of import infrastructure, LNG facilities, storage capacity and gas quality.

Spain

Spain is Europe's fifth largest natural gas market, consuming 34 bcm of gas in 2007. LNG accounted for 70%, or 24 bcm, of its natural gas requirements. Spain has been Europe's fastest-growing gas market in recent years. This growth had taken place independently of the power sector; however, from 2002, as CCGTs were commissioned, the power sector has driven growth, doubling its gas use over the 2001 to 2007 period. Gas-fired power generation's share of gas consumption has grown from 5% to 34% over the period between 2000 and 2006.[35]

35. "Planificación de los Sectores de Electricidad y Gas 2008-2016" published by the Spanish Ministry of Industry, Tourism and Trade (May 2008).

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, gas consumption for power generation is dependent on the availability of wind energy and hydro, a fact that partly explains gas consumption patterns in 2007. A wet and windy first six months of 2007 led to a 37% and a 22% increase in wind-power and hydro generation respectively, which resulted in reduced consumption of natural gas in this period. A different weather pattern (drier and less windy) emerged in the second half of the year, together with a colder winter in comparison with 2006, leading to a sharp increase in demand during the last months of the year and into 2008. Gas use in the six months to April 2008 was 22% up on the same period a year earlier.

The Hydrocarbons Law of 1998 first established the basic principles of the security of supply in the Spanish natural gas market as a requirement for natural gas companies to store minimum security stocks. A certain amount of this stock is considered "strategic", which only the Government is entitled to use.

Subsequent legislation, such as Royal Decrees of July 2004 and December 2007, has further developed and strengthened security of supply measures by setting out the requirements to maintain minimum stocks of natural gas and to diversify the sources of the imported gas.

Regarding the maintenance of minimum stocks, shippers have to keep up to 20 days of sales in stock, of which ten days strategic stocks and ten days of commercial stocks. Strategic stocks are equal to ten days of previous year's sales; these are under governmental control. Commercial stocks are equal to ten days of sales, corresponding to two days of previous year's sales, and eight days of previous October's sales. The Transmission System Operator, also responsible for the organisation of storage, allocates available storage volumes to companies, which pay regulated fees for the storage. These fees cover the variable cost of storage. The fixed costs are reimbursed separately at regulated conditions.

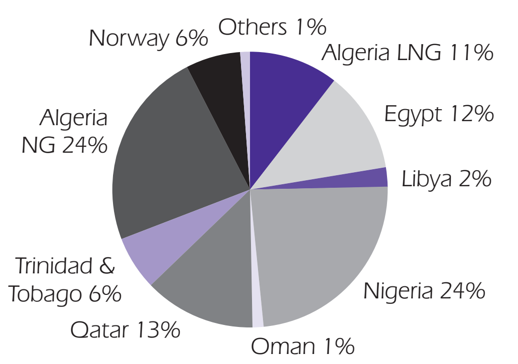
Regarding diversification of supply sources, no more than 50% of gas may be imported from one source/country. Natural gas companies must diversify their contracts in order for this figure to remain below the mentioned level. Only large companies, with more than a 7% share of the market, are obliged to diversify. In 2007, Spain imported LNG from seven countries and pipeline gas from two main sources. Both pipeline gas and LNG are imported from Algeria, making it the country's largest source of gas, but having lowered sharply its share in last years from about 2/3 to just 1/3 of the total imports.

Other legislation concerning security of supply includes the Resolution of July 2006 of the Energy Director of the Ministry of Industry, Tourism and Trade, which defined the interruptibility process and the allocation procedure in times of emergency.

The Network Code of the Spanish natural gas system regulates the normal operation of the natural gas system and its operation in exceptional situations.

The Code includes measures that can be put into place in case of a supply disruption. These rules are continuously revised and updated by a panel comprising representatives of the gas industry and public organisations.

Figure 42 Gas imports in Spain (2007)



Source: Overview of the Spanish Natural Gas Market in Year 2007, Ministerio de Industria, Turismo y Comercio.

Each year, the Energy Director of the Ministry of Industry, Tourism and Trade updates its Winter Action Plan. This plan includes mandatory provisions for all shippers to strengthen security of supply during the winter season, a minimum entry flow in the Spain-France interconnection at Larrau, mandatory minimum stock levels in LNG terminals, and certain restraints on the use of underground storage in order to build up stock levels.

The Government also carries out an annual mandatory planning process in order to ensure that the necessary infrastructure to transport, store and supply natural gas to consumers is built in accordance with the requirements of demand forecast. This planning includes building up redundant entry and transport capacity. The current network system consists of six LNG regasification plants, a subsea pipeline to Algeria, two pipelines to Portugal and France (the latter connecting Spain with Europe), two underground storage sites and a network of distribution pipelines inside the country. An additional regasification plant and a third underground storage are currently under consideration, both of which will also contribute to strengthening the security of supply. The Spanish Ministry of Industry, Tourism and Trade recently approved the new document titled "Planning of Electricity and Gas Sectors 2008-2016 – Development of Transportation Networks"[36] that replaces the current three year old arrangments.

Finally, Spanish legislation provides the means to survey and monitor security of supply. The Ministry of Industry, Tourism and Trade, in collaboration with Corporación de Reservas Estratégicas de Productos Petrolíferos (CORES), the agency in charge of managing natural gas minimum stocks, regularly audits natural gas stocks held by the industry.

Poland

Supplies of natural gas for Poland's domestic needs in 2007 were just over 15 bcm, two thirds of which were imports. The bulk of the imported gas, 6.85 bcm or 45% of consumption, comes from Russia. Further supplies come from Germany, Uzbekistan, the Czech Republic and Ukraine and amount to 3.27 bcm.

36. http://193.146.123.247/aplicaciones/wenergia/planificacion2008-2016.pdf.

Apart from improving the emergency system, the aim of the Polish government is to diversify the sources of natural gas supply. In 2000, a decree on diversification of gas imports required that supplies from one source should not exceed 72% in the period between 2005 and 2009, then 70% between 2010 and 2014, 59% between 2015 and 2018, and 49% after. This decree drove diversification away from Russian gas by importing Central Asian gas. In 2006, the Council of Ministers adopted a resolution on mechanisms to enhance energy security, which stated that a pipeline connecting the domestic transmission system with North Sea gas deposits and the construction of an LNG regasification terminal would fulfil the objective of diversification of natural gas supply. Work on these diversification projects is currently underway. In December 2005 the Plenipotentiary for the Diversification of the Supply of Energy Carriers to the Republic of Poland was appointed and work commenced on a programme of gas and oil supply source diversification.

Storage capacity in Poland amounts to 1.6 bcm (0.284 bcm of compulsory stocks, 0.05 bcm for the needs of the gas transmission operator, and the remainder being commercial stocks). Shippers and large importing consumers of natural gas are obliged to maintain stocks of natural gas in a quantity corresponding to at least 11 days of the average daily amount of gas they import to Poland. The quantity of the required gas stored will gradually increase until 1 October 2012, when it will correspond to 30 days of the average daily amount of the gas imported between 1 April of the previous year and 31 March of the relevant year. Exemptions from the obligation to hold stocks apply if the gas enterprise has fewer than 100 000 consumers and annually imports less than 0.05 bcm of natural gas. The exemption is granted for up to one year or until a change in the circumstances that constituted the grounds for granting an exemption to this obligation occurs.

These stocks must be maintained in installations of a standard that enables delivery of the entire inventory to the gas transmission system within 40 days and may only be released by the gas transmission system operator or by the gas combined system operator, under an administrative decision of the Minister of Economy.

By 15 May each year, relevant businesses must report to the Minister of Economy and to the President of the Energy Regulatory Office about actions taken between 1 April of the previous year and 31 March of the relevant year to ensure fuel security. By this date, gas importers must submit the information determining their obligation to hold compulsory stocks, which is then approved by the President of the Energy Regulatory Office.

Procedures are also in place to be applied if disruptions occur in the supply of natural gas to the gas transmission system or if natural gas consumption increases in an unexpected way.

United Kingdom

The United Kingdom is one of Europe's largest consumers and producers of natural gas. In 2007, demand for gas was 94.56 bcm, of which 75 bcm was produced domestically and the rest imported, either by pipeline from Norway or continental Europe, or via LNG. While indigenous reserves are the main source of gas at the moment, production has been falling by around 8 – 10% per year since 2004. The government forecasts that the United Kingdom could be importing as much as 80% of its gas requirements by 2020. While the country hopes to benefit from overall diversity of supply, it will face a greater risk as a consequence of potential disruptions elsewhere than otherwise would have been the case.

In many regards, the United Kingdom has lead the way in terms of energy policy. It was one of the first to liberalise its gas markets via a process of industry restructuring, privatisation, competition, open access to networks and customer choice. Unlike many countries, a key element of United Kingdom policy has been the use of the market to achieve policy goals. It relies on market actors, responses to prices signals, and private participation. The government will generally look to market-based instruments when market failure is identified.

This faith was put to the test in February 2006 when a combination of events, including reduced domestic production, underutilised capacity on the Belgium Interconnector and a fire at the Rough storage facility combined to cause a potential supply-demand imbalance. A sharp rise in spot gas prices ensued but there were no supply interruptions and the market continued to function. The government exercised considerable restraint in leaving the market to solve what could have been a serious gas shortage. High gas prices brought an immediate response from customers as some reduced demand, and others, particularly electricity generators, switched to other fuels, notably coal.

Again, in early February 2008 the market withstood another stress test when a fire broke out at the Shell sub-terminal at Bacton. This sub-terminal can currently deliver about 50 mcm per day, which equals 15% of average winter demand. While within-day gas prices rose, increasing by up to 25%, before the blaze was reported, market disturbance was limited and customers found their gas elsewhere for the duration of the outage which continued until 3 March. The same happened at the beginning of autumn of 2007, when volatility in Norwegian gas flows combined with concomitant technical and operational problems - notably South Morecambe maintenance, Shell's Goldeneye platform unexpected shut down, late start-up of the Tampen link, the annual planned maintenance of the Interconnector and the Rough storage site and BP's Bruce and Rhum fields' problems- were at the origin of relative high spot prices when compared to spot prices during earlier autumns (see Figure 44).

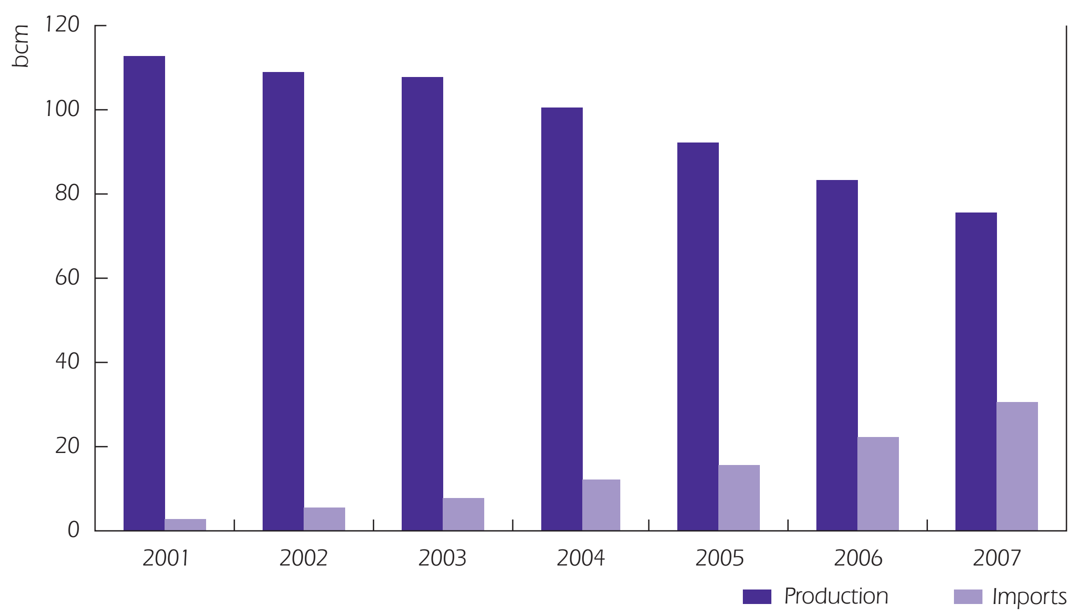
Bacton is one of the largest gas terminal facilities in the United Kingdom. Gas lands onshore at the three producer terminals from the southern North Sea and from the Shearwater Elgin Area Line and is then distributed to United Kingdom customers via the National Grid terminal, or to Belgium via the Interconnector system. When in reverse flow mode, the Interconnector Bacton Terminal is used to import gas into the United Kingdom.

One of the primary challenges facing policy makers in the United Kingdom is energy security, and in this regard a White Paper[37] was released in May 2007. The policy paper signalled the government's intention to continue to use the market to meet its energy goals in the context of continued reliance on fossil fuels for the longer term and an increasing dependence on imports of these fuels.

Current market arrangements for gas include a set of measures designed to protect the United Kingdom from potential supply shortfalls and deliver an appropriate level of security of supply under existing market conditions.

In the short term, price signals provide incentives for market participants to take action to bring the gas supply and demand into balance, for example by encouraging suppliers to increase the amount of gas provided; and large consumers (such as gas-fired power stations) to reduce their consumption. In this latter aspect, it is important that the electricity markets function properly and not cause shortages in the power sector. In the longer-term, price signals indicate the need for greater capacity or market flexibility, and encourage market participants to undertake investments to provide new capacity, in supply or storage, and to improve their demand responsiveness or the diversity of their supply portfolios.

Figure 43 **United Kingdom gas production and imports (2001-2007)**



Source: IEA.

37. Meeting the Energy Challenge, A White Paper on Energy, May 2007, Department of Trade & Industry.

In relation to pricing mechanisms, the regulatory framework further ensures that market participants have pricing incentives to guarantee security of supply to gas customers, through four main mechanisms:

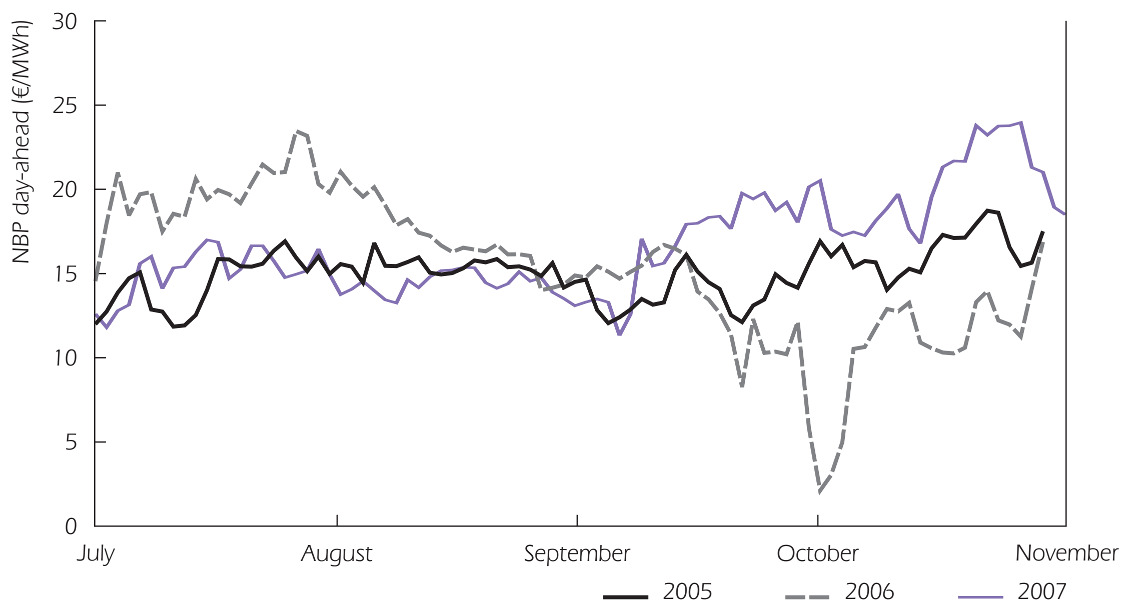
1. Cash-out arrangements by which shippers/suppliers that fail to deliver contracted volumes on a daily basis must pay an imbalance charge or cash-out price, exposing themselves to potentially very high costs;

2. Emergency cash-out arrangements which apply when there is insufficient gas to meet demand, further enhance the incentives for shippers to avoid a gas emergency by increasing the penalty that they would pay for having insufficient supply to meet their customers' needs;

3. Supplier/shipper obligations: Ofgem, the downstream gas market regulator in the United Kingdom, implements the relevant EU legislation, licence conditions and the Uniform Network Code (UNC) that place the necessary economic incentives on suppliers to ensure availability of supplies to domestic customers even in the event of severe conditions (conditions which may be expected to be exceeded in only 1 year out of 50, i.e. a "1 in 50 winter");

4. Safety monitors (otherwise known as storage monitors) ensure that there is a minimum amount of gas available in storage, across all storage sites in the United Kingdom, to underpin the safe operation of the gas transportation system in a severe winter. These safety

Figure 44 **NBP Day-ahead from July to November (2005-2007)**



Source: Heren.
Note: Prices hit a trough at the start of October 2006 because of an oversupplied market: the south leg of the Langeled pipeline and the expansion of the Interconnector came on stream. In addition, a cargo of LNG arrived at the Isle of Grain terminal.

monitors act to protect the gas supply of domestic customers.

The market framework has previously delivered major investments by market participants in a wide range of new import pipelines and terminals and also storage infrastructure.

During winter 2006-2007, a number of new investments in import capacity were completed, such as the expansion of the Interconnector from Belgium (IUK), the construction of the Langeled pipeline from Norway and the BBL Interconnector from the Netherlands, as well as the Teesside Gas-Port providing additional LNG import capacity of 4 bcm per year, which was commissioned in February 2007 but has not been used since then.

In addition, there are two LNG import facilities being constructed in Milford Haven, which will further diversify the sources of gas used to supply the United Kingdom. Together with expansion of import capacity at the existing LNG terminals at the Isle of Grain and Teesside, this will increase LNG import capacity of the country by 31 bcm per year.

Storage capacity available in the United Kingdom is also set to increase substantially. If all the storage projects currently under construction are completed (excluding storage at LNG import terminals) the proportion of peak day demand that could be met by storage operating at its maximum rate would increase from 28% in 2006/07 to 46% by 2015/16.

Recognising that existing arrangements may not deliver the necessary measures to manage future supply risks, the government is undertaking the following steps:

- Reducing gas consumption by encouraging energy efficiency and to increase demand side flexibility by measures such as smart metering and billing through the Carbon Emission Reduction Target (CERT) scheme;

- Improving the effectiveness of the gas market, through better energy market information and working with the European Union to improve competition in the EU gas market;

- Increasing gas storage and import infrastructure by facilitating the construction of gas supply infrastructure both onshore and offshore, through reforms to the planning and licensing regimes,[38] including a fit-for-purpose licensing regime for offshore gas storage and unloading of LNG.

The United Kingdom's growing dependence on imported gas has also raised the issue of the relationship between existing gas quality specifications and the qualities of gas available on international markets, both LNG and pipeline imports from Europe. In recent years the government commissioned substantial research and established a Gas Quality Review Group. Following the Group's findings, and balancing the costs and benefits, the Government has announced an intention

38. White Paper 2007, Planning for a Sustainable Future, Department of Communities and Local Government.

not to propose changes in gas specifications before the end of the next decade.

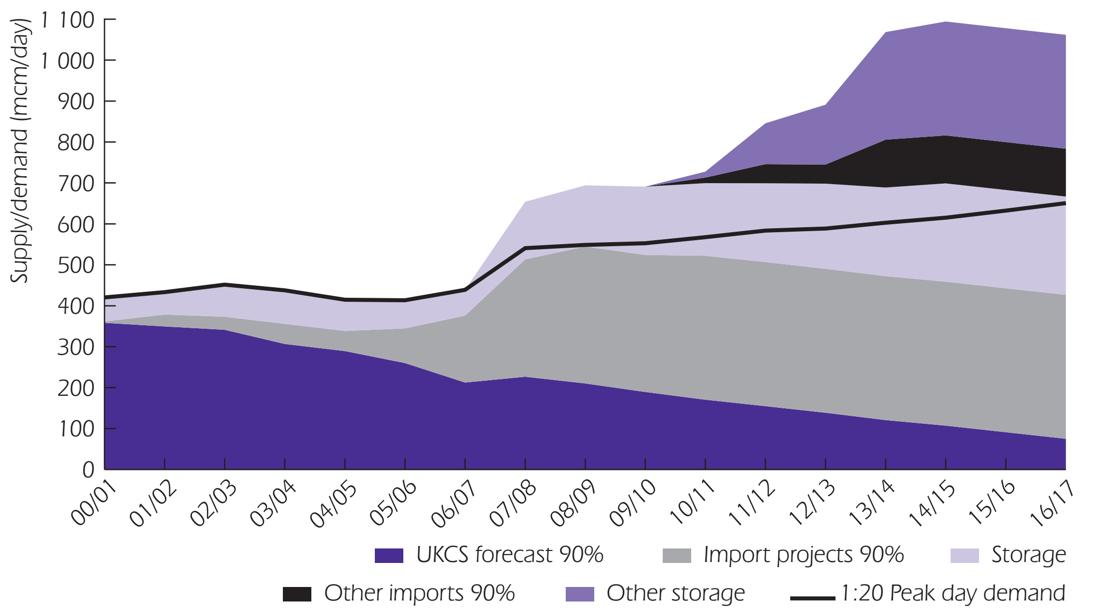
While the United Kingdom market has delivered high levels of reliability for the supply of gas to consumers, despite interruptions and price shocks in recent years, there still exists a possibility of an unexpected shortfall in supply. In this regard and prior to the publication of the 2007 Energy White Paper, the government commissioned a report[39] on the implications of the measures set out above on security of supply. The report sought to assess the risk of forced outages to the system and also the price distributions associated with the underlying supply-demand balance.

Gas stocks

IEA member countries are required to maintain total oil stock levels equivalent to at least 90 days of the previous year's net imports. These stock obligations may be met by holding stocks as government emergency reserves, through specialised stockholding agencies, or by placing minimum stockholding obligations on industry. They are designed to manage the largest historical supply disruption experienced to date.

Strategic gas stocks are physical stockpiles of natural gas which are not available to the market under normal conditions and tend to be owned and/or

Figure 45 **Potential peak supply capacity in the United Kingdom**



Source: National Grid Gas Transportation Ten Year Statement 2007. Note: actual demand (2000/01 to 2006/07) reflects highest demands experienced historically, whereas forecast demand is on the basis of much lower temperatures (1 in 20 winter) – hence apparent increase in demand from 2006/7.

39. An Assessment of the Potential Measures to Improve Gas Security of Supply, Department of Trade and Industry, May 2007.

controlled by governments. In addition to protecting customers against particularly cold winters, strategic gas stocks can be understood to offer protection for consumers against non-market supply disruptions such as those caused by infrastructure failure. To some they are viewed as the "equivalent of strategic oil stocks" but in reality gas and gas storage differ significantly from oil and oil stocks.

A fundamental difference is one of cost. Previous IEA work suggested that the initial capital cost of gas storage is between five to seven times the costs of underground oil storage facilities per tonne of oil equivalent (toe) stored. The capital cost of LNG storage facilities under construction at that time was 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 were therefore deemed much more expensive than oil stocks. Variable costs for maintaining gas in storage are also significant. In addition, gas stocks must be made available through existing pipeline infrastructure. If the infrastructure fails, or is inadequate to distribute stocks as widely as needed, the stocks will be worthless.

France and Germany provide good examples of the importance some countries place on storage facilities. The Germans consume much the same amount of gas as the United Kingdom (96 bcm in 2007), but have five times the level of storage capacity. Both France and Germany rely to some extent on United Kingdom's summer exports via the Interconnector to fill their storage facilities.

In the United Kingdom, storage represents approximately 4% of annual demand with total working capacity available of 4.4 bcm. The main storage facility is Rough (3.3 bcm). Several projects are under construction or planned, which could almost triple storage capacity over the medium term. Aldbrough storage (420 mcm) is expected to be operational in 2008.

France maintains 15 gas storage facilities at 14 sites, 12 of which are aquifer storage units and three salt cavities. The total available working capacity is 11.7 bcm. France is considering increasing its storage capacity through the expansion of existing storage units such as Lussagnet (TIGF), Céré, and Etrez (GDF) and the construction of new facilities such as Trois Fontaines and Hauterives.

There are 47 storage facilities in Germany, two thirds of which are depleted fields and capacity is regularly expanded. Capacity owners are predominantly supraregional and regional companies. The total available working capacity is 19.4 bcm. Over 4 bcm of new capacity is planned in Germany, most of which consists of salt caverns and is sponsored by non-German companies. For example, Gazprom Marketing & Trade is developing facilities in two salt caverns at Etzel, while the company's German affiliate ZMB is currently investigating the possibility of aquifer storage at Hinrichshagen.

Access to storage in Germany is negotiated while in France and the United Kingdom access is regulated.

ADVANCED TECHNOLOGIES TO DELIVER GAS TO MARKETS

Advances in technology have served as major triggers for the development of natural gas markets since the beginning of the natural gas industry. Technological progress is crucial both in accessing new conventional and unconventional gas resources and converting them into reserves, and in developing new means to bring the gas to markets. Furthermore, delivering greater efficiencies in upstream and downstream sectors is a key objective of research and development to ensure gas market sustainability over the long-term. In a globalising gas market – one with rising prices, tight supply prospects and increasing environmental constraints – frontier gas resources will probably see their contribution to global gas supply growth in the near future.[40]

In this section some of the recent advances in upstream and transportation technologies for natural gas are presented.

The potential of unconventional gas

The borders between conventional and unconventional hydrocarbon resources have historically been shifting depending on the definition of what is considered to be conventional technology at any particular point in time. Technologically and economically accessible resources i.e. reserves, are renewed and extended whenever technological innovation allows these energy resources to be extracted, shipped and sold on an economically viable basis.

At present, unconventional gas resources are classified in six main categories: tight gas, deep gas, geopressurised zones, shale gas, coalbed methane and methane hydrates.

Tight gas is methane trapped in unusually impermeable and non-porous rock, sandstone or limestone formations. Extracting techniques include fracturing and acidising and incur additional costs. Around 15% of Canada's present gas production and 20% of recoverable United States' gas reserves are classified as tight gas.

Deep gas is located beyond 5 000 m underground. Advances in deep drilling allow reaching such deposits and have improved the economics of deep gas reserves.

Geopressurised zones are characterised by unusually high pressure and are therefore difficult to exploit. Moreover, these are located at great depths, beyond 3 000 m. The total amount of these reserves is not precisely estimated and ranges from 142 to 1 389 tcm, which is considerable compared to the current level of recoverable reserves (180 tcm).

Shale gas is methane contained in organic rich rocks dominated by shale. Extraction of shale gas is more costly, due to shale rock properties, and only about 15% of methane in shale gas formations is recoverable.

40. This chapter is based on the publication "Technologies for Global Natural Gas Expansion, IEA Working Party on Fossil Fuels", 2008.

Coalbed methane (CBM) is natural gas trapped in coal seams. Thus it is also called coal seam methane (CSM). Previously vented into the atmosphere to prevent gas explosions in coal mines, its capture is interesting not only as an additional supply source but also for environmental reasons, as it allows the capturing and burning of a powerful greenhouse gas in a cost-effective manner.

Methane hydrates are made up of molecules of methane trapped in a lattice of frozen water, and resemble melting snow. These resources are located in the polar zones (Arctic onshore) as well as in deep water continental shelves. This resource is not expected to provide substantial supplies in the next 10 to 20 years. However, methane hydrates constitute the largest deposit of organic carbon on the planet, with recoverable reserve estimates ranging from 200 tcm to over 2 000 tcm, more than all conventional hydrocarbon reserves known.

Improving gas transport

Gas is more costly to transport than oil or coal. Improving gas transportation efficiency is therefore an important area for new technologies.

The **LNG chain** has benefited from several innovative methods in liquefaction plants, shipping and regasification. In the liquefaction process, advances in refrigerant compressors, heat transfer equipment, use of the all-electric drive option, as well as economies of scale in projects, have substantially driven down costs.

Offshore liquefaction systems may offer the advantages of cheaper costs and faster construction for offshore stranded gas deposits, where the size of the reserve and the distance to shore make a pipeline connection to an onshore liquefaction plant costly and time-consuming.

Economies of scale have also helped enhance efficiency in LNG shipping, by increasing the capacity of tankers. Advances in vessel propulsion technologies helped reduce the amount of gas used as fuel. Regasification advances consist notably in new technologies allowing regasification on board of the LNG ship and docking with a specialised buoy attached to a gas pipeline to shore. Development of offshore barge-mounted floating regasification terminals has also provided added flexibility to new LNG projects.

Pipeline infrastructure is ageing in many gas markets, while at the same time more pipelines are needed both to bring new supplies to markets and to expand the existing consumer base downstream. For gas transmission pipelines, new pipeline surveillance technologies include autonomous and intelligent robots using cameras to monitor pipelines from the inside and detect in advance potential damage; as well as radar/laser helicopters or planes detecting leakages on underground pipelines. Complex modelling of telemetric data helps provide relevant warnings in cases of a damaged pipeline. Such technological advances increase pipeline security and allow refurbishment programmes to be preformed in a timely manner.

Deep water pipeline installation through the J-lay method (as distinct from the S-lay used traditionally, for up to 2 500 metre depth) allows pipelines to be laid at up to several kilometres depth. The challenges of such installation include pipeline insulation and material strength adequate to withstand pressure, at the same time as light weight so that the pipe-laying ship can bear the tension of the submerged pipeline.

Arctic gas pipeline projects represent another frontier for gas transportation technologies. The Alaska gas pipeline project in North America, proceeding through permafrost, will require special measures to prevent damage to the pipeline caused by interaction with the fragile permafrost soil. For pipelines going from offshore to land in these regions, the ice-scouring risk may be mitigated by the pipe-in-pipe technique, which also reduces the need to bury the pipeline too deeply and disturb sediment and sea floor in a fragile environment. Ice-proof offshore equipment is also needed for pipeline maintenance.

Gas-to-liquids technology (GTL) provides another option for bringing gas to markets: it allows the production of a liquid fuel from natural gas, cleaner than basic gasoline or diesel products. This can then be transported in normal tankers like oil products. GTL is obtained by oxidising the natural gas at high temperature, converting it to synthetic gas (syngas). This is in turn transformed into a range of liquid hydrocarbons through catalysed chemical reactions (Fischer-Tropsch process). The waste by-product of this process is CO_2. GTL is a potential solution to stranded gas reserves (estimated about half of total reserves – too remote or small to justify the construction of an LNG plant or a pipeline). The world's first medium-scaled commercial GTL plant was built by Shell in Bintulu, Malaysia in 1993 with an initial capacity of 12 500 bbl/d. Another, even larger-scale plant, Oryx GTL, a joint-venture of Qatar Petroleum and Sasol, was commissioned in 2006 in Qatar. It has been plagued by fine material in the Fischer-Tropsch process and is grossly underperforming since then – having achieved a stable capacity of only 16 000 bbl/d so far, instead of the planned 34 000 bbl/d. Only one additional commercial scale GTL plant, Shell's Pearl GTL plant in Qatar with an expected capacity of 140 kbbl/d, is expected to start production by 2010. Even though the technology was expected to be flourishing only a few years ago, it still has to demonstrate its commercial viability.

Better access to gas reserves

Improved exploration and development technologies have helped maintain and increase natural gas reserves over time. The exploration phase for natural gas faces the same difficulties as oil, in that it is difficult to predict initially which hydrocarbons (oil or gas) could be present in a potential discovery field. Therefore, gas has benefited from 3D (three-dimensional) seismic imaging techniques and more powerful computing, as well as multi-azimuth surveys (imaging using multiple sources) which provide more accurate imaging of underground reserves. In deep water, very low-frequency electromagnetic wave emissions help to confirm the presence of oil and gas resources.

New drilling technologies used in the **production** phase allow better penetration rates even in very deep water (beyond 3 000 m), with lower costs and higher efficiency. Such technologies include for example, multi-dimensional drilling (multiple wells from the same wellhead source) and extended reach drilling (up to 11 000 m). Development of sub-sea production facilities instead of above-water platforms is of interest, as these can reduce the risk of weather and ice-caused damage and minimise environmental risk.

Sour gas, or natural gas containing high concentrations of hydrogen sulphide, (H_2S) exists in numerous deposits notably in North America, Middle East and also in China. Its improved treatment in terms of public security and environmental effects allows the recovery of significant amounts of natural gas as well as other by-products for use by the chemical industry.

Methane recovery during the natural gas cycle is of major importance. Methane, or natural gas (CH_4), is 21 times more powerful than CO_2 in terms of greenhouse effects. Total methane emissions from all sources, including non-energy sources, are estimated as responsible for 16%[41] of global anthropogenic GHG emissions. Nevertheless, its lifecycle in the atmosphere is relatively short – 12 years – making reductions in methane emissions a worthwhile aim for mitigating climate change in the near term. The oil and gas industries account for 17% of total CH_4 emissions, through flaring, leaks and losses. Reduction of these emissions would also help save gas for additional consumption. The most important source of methane emissions is landfill gas (LFG), with 50% of total global methane emissions. LFG recovery through a series of wells and vacuum systems, with minimum processing, allows its usage for distributed electricity generation or as an alternative vehicle fuel.

Challenges of frontier gas resources

Discovering and exploiting frontier gas resources, in very deep water or in the Polar zones, requires R&D and technology advances to match the significant challenges, while preserving the fragile ecosystems. Considerable hydrocarbon reserves are located in the Arctic region and under deep water, for example Shtokman in Russia. The protection of the environment while reducing drilling and transportation costs constitutes a major challenge for the oil and gas industry.

The Snøhvit LNG project offshore Norway is an initiative to apply major technological innovation in a challenging frontier area, including the first wholly sub-sea hydrocarbon production in the Norwegian continental shelf; piping of the natural gas and associated liquids to an onshore LNG facility; separation of the natural gas, liquids and CO_2; and carbon capture and storage (CCS) to

41. US EPA, 2006 or 14.3% according to IPCC Climate Change Report 2007.

reduce further the potential impact on the environment. Significant problems incurred in the liquefaction plant during the initial production stages and have prevented the project from achieving its production target during the first year. However, the expectation is that these teething problems in the technology can be resolved in the short-term.

The Ormen Lange gas field, again on the Norwegian continental shelf, is another example of a particularly difficult project, situated in deep water (>2 800 m) in a very harsh maritime environment (up to 30 m high waves, strong current, near zero temperatures). Again, a subsea production complex was designed for Ormen Lange, with a complex set of techniques to control pressure drops, avoid the formation of hydrates (ice clumps), and ensure overall security of supply for the customers of Ormen Lange gas.

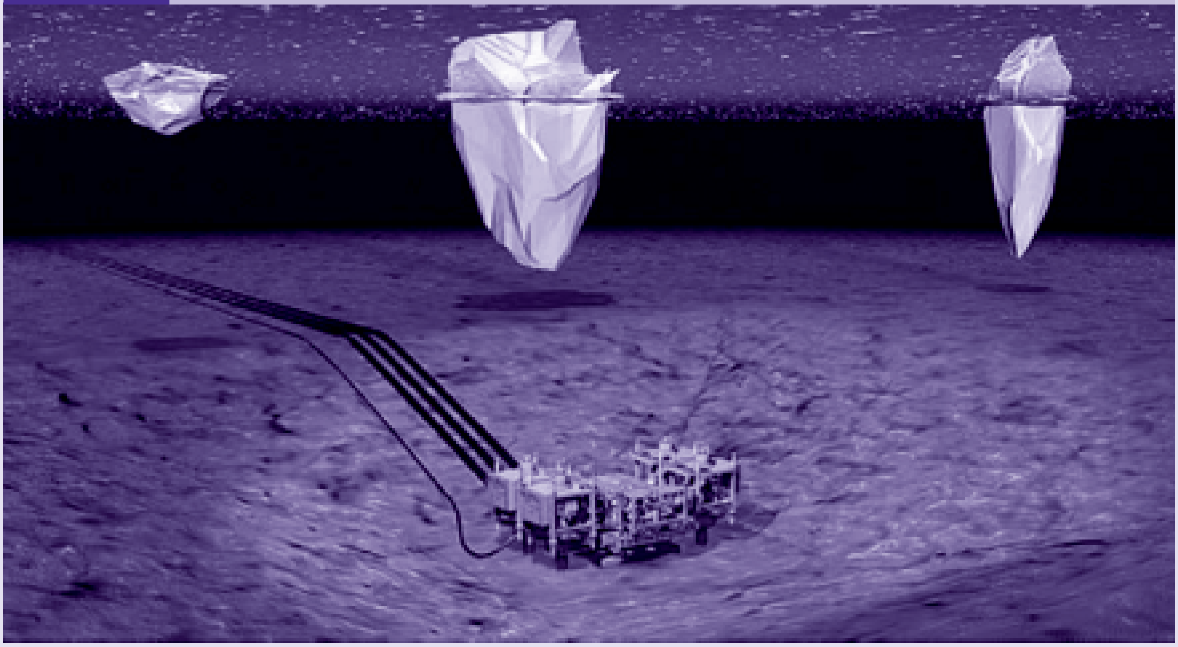
As in the Snøhvit project, Ormen Lange has processing facilities onshore for separation and treatment of the multi-phase flow of gas and liquids. The Ormen Lange gas is destined for the United Kingdom, running from the processing plant at Nyhamna through the longest subsea pipeline, Langeled, via the Sleipner platform in the North Sea to Easington on the United Kingom east coast (1 200 km). With the expected decreasing pressure of the field in coming years, a subsea compressor station has been designed and is expected to be built after 2012-13.

Computer simulation has played an essential role in the development of these projects, both for design of the systems and installations and for assessment of their performance against all the potential environmental and weather hazards which could affect the normal functioning of the facilities in this area.

Finally, exploiting Arctic gas resources requires new technologies for all- or part-year ice-covered sea, necessitating ice-resistant structures and sub-sea systems for installation and monitoring of production and transport facilities, as well as new technologies and methods of ensuring safety of personnel and evacuation in hostile environments in case of accidents. Such ventures, combining high risk with high costs, pose major challenges in terms of developing high performing, efficient and environmentally protective technologies to bring new gas resources to markets.

New gas deposits found in extreme conditions or in unconventional form will constitute a continuously increasing part of proven gas reserves in the world. These are more difficult to access, develop, exploit and transport to the market, both in terms of costs and of risks to the security of supply and to the environment. In conclusion, both producing new gas resources and getting the gas to markets are likely to be more expensive and can be vulnerable in the long term, despite advances in technology. Efficiency gains throughout the gas value chain will therefore be vital to make the best use of natural gas and optimise the total costs of bringing the needed resource to the market.

Figure 46 Under-ice challenge for Arctic systems



Source: StatoilHydro.

ANNEX A: DEVELOPMENTS IN LNG RECEIVING TERMINALS

France

In addition to the two existing LNG receiving terminals – one at Fos on the Mediterranean Coast and one at Montoir on the Atlantic Coast, both wholly owned by Gaz de France – a third, the Fos Cavaou terminal is under construction near Marseille. The terminal is a joint venture between Gaz de France and Total, with initial capacity of 8.25 bcm per year. It will start receiving LNG in 2009, instead of the original target the fourth quarter of 2007, because of construction delays and piping failures during the testing phase in February 2008.

Additional new regasification projects are planned by companies other than the incumbent players in the country's gas business to add three terminals by around 2012. National public consultation processes are underway for the three proposals.

Among them, Électricité de France's wholly owned Dunkerque project in northern France is the most advanced. The project completed the public hearing phase at the end of 2007. The initial targeted capacity is 6 bcm in 2012, expandable to 12 bcm per year at a later date. The company has withdrawn from an earlier capacity deal at the Gate terminal project in Rotterdam in the Netherlands to concentrate on the Dunkerque plan, after acquiring capacity access at the Zeebrugge terminal in Belgium, as well as Qatari LNG supply to the terminal, and equity and capacity stakes at the Rovigo offshore terminal under construction in Italy through the company's equity holding in Italy's power company Edison.

Table A.1 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	2009
Dunkerque	Électricité de France (EdF)	Planned	6	2012
expansion		Proposed	6	TBD
Le Havre (Antifer)	Poweo, CIM, E.ON, Verbund	Planned	9	2012
Bordeaux (Le Verdon)	4Gas	Planned	9	2013
Fos (Shell)	Shell	Proposed	8	2015
Bordeaux (Le Verdon)	Endesa	Proposed	4	TBD
Potential total			**67**	

Source: Natural Gas Information 2008, IEA, company information.

The Gaz de Normandie project at Antifer, near Le Havre, west of Paris, is targeting a 2012 start-date, with its initial capacity of 9 bcm per year equally shared by the project participants - 34% owner independent Poweo (an independent power producer and marketer), 24.5% each by Germany's E.ON and Austrian state power firm Verbund. The other participant, Compagnie Industrielle Maritime, has 17% with no capacity allotment.

Dutch terminal developing company 4Gas is also conducting a planning process for a 9 bcm per year terminal at Le Verdon near Bordeaux. Another terminal is being considered by Endesa also at Le Verdon, and an 8 bcm per year terminal is being studied by Shell at Fos.

Gaz de France's open season for the expansion at its Montoir terminal did not attract interest from potential shippers. The capacity of the terminal would have been expanded from current 10 to 12.5 or 16.5 bcm per year in 2010 or later, depending on the level of interest from the market.

Belgium

Belgium has an LNG receiving terminal at Zeebrugge, built in 1987. Suez's Distrigaz subsidiary owned 100% of the capacity until 2006. The capacity of the terminal is being expanded from 4.5 bcm to 9 bcm per year in 2007 and 2008. As part of this expanded capacity came online in April 2007, the number of capacity holders at the terminal rose 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). The capacity right of QP and ExxonMobil was sold to EDF Trading in July 2007, with the entitlement of Qatar's RasGas LNG supply. EDF subsequently has admitted the capacity has not been fully utilised as the transit pipeline capacity to France is inadequate.

To facilitate European Commission approval of their proposed merger, Gaz de France and Suez proposed creating new gas competitors in France and Belgium in September 2006. The companies would set up three structures in Belgium out of Fluxys, another Suez company. Through one of them, Fluxys International, the merged group would retain the effective ownership of the Zeebrugge terminal. Fluxys says it will facilitate secondary capacity rights trading at the terminal. In December 2007, Fluxys announced its intention to expand the capacity by 2015-16 if there is sufficient market interest.

Separately, Belgian shipping company Exmar applied to the local port authority at Zeebrugge for a concession to build an LNG discharge and ship-to-ship transfer scheme, to be on-line in late 2009 or early 2010.

The Netherlands

Four LNG terminals are being planned in the Netherlands, which has none at the moment. Two onshore and one offshore import projects have been proposed for Rotterdam.

Table A.2 LNG terminals in Belgium

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Zeebrugge	Fluxys	Operating	4.5	1987
expansion I		Operating	4.5	2008
expansion II		Proposed	9.0	2015-16
Zeebrugge offshore	Exmar	Proposed		2010
Potential total			**18.0**	

Source: Natural Gas Information 2008, IEA, company information.

The Gas Access to Europe (Gate) project received a final investment decision (FID) from its sponsors Gasunie and Vopak in December 2007, after securing capacity commitments from electric power utility Essent, Denmark's Dong, and Econgas, a subsidiary of Austria's OMV for 3 bcm per year each. The 9 bcm per year initial capacity is scheduled to be operational in the latter half of 2011. The three capacity holders will acquire a 5% equity share in the terminal. A second stage is also being considered to expand the capacity to 16 bcm per year. This is a unique example of an FID for a receiving terminal project in Europe, where none of the capacity holders has secured long-term supply sources.

The LionGas project promoted by the terminal developer 4Gas, also eying 9 bcm per year around 2011, received interest from southwest German power generator EnBW and Dutch utility Eneco in 2007, who signed memoranda of understanding on reserving 3 bcm per year and 2 bcm per year capacities, respectively, plus equity. The project has also received a positive response to its environmental impact statement from government regulators.

Table A.3 LNG terminals in the Netherlands

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Rotterdam (Gate)	Gasunie, Vopak, Essent, Dong, OMV	FID	9	2011
expansion		Proposed	7	2014
Rotterdam (LionGas)	4Gas	Proposed	9	2011
Rotterdam (offshore)	Taqa	Proposed		2010
Eemshaven	Essent, Gasunie, Vopak	Proposed	10-12	2011?
Potential total			**35-37**	

Source: Natural Gas Information 2008, IEA, company information.

Taqa – the national energy company of Abu Dhabi, the United Arab Emirates (UAE) – announced in February 2007 plans to build an LNG installation off the coast near Rotterdam, utilising onboard regasification technology and offshore depleted gas fields for gas storage. The company said in December 2007 that, if there was sufficient interest shown through its open season, the project would move to selecting an engineering contractor, with first cargoes anticipated in 2010. If the level of interest is high, the project could use a floating storage and regasification unit (FSRU).

Gasunie and Vopak also joined Essent in the 10-12 bcm per year terminal planned for the Port of Eemshaven near Groningen in December 2007, replacing the previous partner ConocoPhillips who withdrew from the project in September 2007.

Germany

Deutsche Fluesigerdgas Terminalgesellschaft, a joint venture between E.ON Ruhrgas (78%), Germany's VNG (10%), and BEB joint venture between ExxonMobil and Royal Dutch Shell (12%), plans to build an LNG receiving terminal at the deepwater port of Wilhelmshaven, in northern Germany, near the major underground gas storage facilities in the country, with an initial sendout capacity of 10 bcm per year in 2011-2012. A final investment decision has not been made as the front-end engineering design study has not been completed and supply sources have not been secured. E.ON Ruhrgas claimed that the open season for the capacity attracted strong interest from potential shippers in summer 2007.

Another German gas and power company, RWE, has a plan to install an onboard regasification LNG receiving facility in the same port of Wilhelmshaven, targeting 2010, in cooperation with Excelerate Energy and German crude oil infrastructure company Nord-West Oelleitung, which in turn is owned by BP (25.64%), Royal Dutch Shell (20.4%), Ruhr Oel (33.69%) and Holborn Europa Raffinerie (20.27%).

Italy

Italy has one operating terminal at Panigaglia near La Spezia. A second terminal, Isola di Porto Levante (Rovigo offshore), is under construction offshore in the North Adriatic Sea. It will be operational in 2008 with a capacity of 8 bcm per year. As this terminal is developed by a consortium of Qatar

Table A.4 LNG terminals in Germany

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Wilhelmshaven	E.ON Ruhrgas, VNG, BEB	Proposed	10.0	2011
Wilhelmshaven GasPort	RWE, Excelerate, Nord-West Oelleitung	Proposed	4.0	2010
Potential total			**14.0**	

Source: Natural Gas Information 2008, IEA, company information.

Petroleum (QP), ExxonMobil and Edison (subsidiary of Électricité de France), LNG supply is expected to come from Qatar.

A third terminal is also planned for offshore Livorno, to begin imports in 2011 with a capacity of 3.75 bcm per year. The project is owned by Spain's Endesa, Italian utility Iride (30.5% each), independent LNG ship owner company Golar LNG (16%), and the project founder, OLT Energy Toscana (23%). Golar will provide one of its existing LNG vessels as a proposed floating terminal. As Endesa's new owners –Italy's Enel and Spain's Acciona– agreed to sell Italian and French assets to Germany's E.ON when it gave up its takeover battle for Endesa, Endesa's stake in Livorno was handed over to E.ON in March 2008.

Work was suspended at the proposed Brindisi terminal and the Italian government suspended its authorisation of the project in October 2007. In 2007, Gaz de France announced that it would conduct initial studies for a terminal offshore Le Marche, targeting a 2014 start. Enel hopes to receive regulatory approval by the end of 2008 for an onshore terminal at Porto Empedocle in Sicily, with a view

Table A.5 LNG terminals in Italy

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Panigaglia	GNL Italia (Snam)	Operating	3.5	1969
expansion		Proposed	4.5	2010
Rovigo offshore	Qatar Petroleum, ExxonMobil, Edison	Construction	8.0	2008
Livorno offshore	Endesa, Iride Mercato, OLT Energy Toscana, Golar LNG, Azienda Servizi Ambientali	Planned	3.75	2011
Brindisi	BG Group	Site preparation suspended	8.0	-
Empedocle, Sicily	Enel	Proposed	8.0	2012
Le Marche	Gaz de France	Proposed	5.0	2014
Rosignano, Toscana	Edison, Solvay, BP	Proposed	8.0	
Taranto, Puglia	Gas Natural	Proposed	8.0	
Zaule, Trieste	Gas Natural	Proposed	8.0	
Monfalcone	Endesa Italia	Proposed	8.0	
Gioia Tauro	LNG Medgas	Proposed	12.0	
Augusta/Priolo, Sicily	ERG Power & Gas, Shell	Proposed	8.0	
Potential total			**92.8**	

Source: Natural Gas Information 2008, IEA, company information.

starting operations in 2012. The volume of the company's Nigerian LNG purchase contract is currently received at Montoir terminal in France under a pipeline gas-LNG swap arrangement with Gaz de France, as Enel failed to construct its own LNG receiving terminal in the 1990s.

Spain

Spain has been one of Europe's fastest-growing gas markets and is the largest LNG importer in Europe, approaching half of European LNG imports. It is the third largest LNG importer in the world after Japan and Korea. Spain's sixth receiving terminal at Mugardos received its first cargo in May 2007. Including this addition, the country's regasification capacity was boosted by nearly 20 bcm, or 50% in two years. The Mugardos terminal is owned by Xunta de Galicia, Endesa Generacion, Union Fenosa Gas (a joint venture between Union Fenosa and Italy's Eni), Grupo Tojeiro, Caixa Galicia, Sonatrach, Banco Pastor and Caixanova. The majority of the gas is consumed at new gas-fired

Table A.6 LNG terminals in Spain

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Barcelona	Enagas	Operating	17.3	1969
expansion		Construction	1.3	2008
Huelva	Enagas	Operating	13.6	1988
Cartagena	Enagas	Operating	9.9	1989
expansion		Construction	1.3	2008
Bilbao	Bahia de Bizcahia*	Operating	8.0	2003
expansion		Proposed	2.5	2012
Sagunto	Saggas**	Operating	6.0	2006
expansion		Construction	1.8	2008
Mugardos (El Ferrol)	Reganosa Group***	Operating	3.6	2007
expansion		Proposed	3.6	2013
El Musel	Enagas	Proposed	7.0	2011
Gran Canaria (Canary Islands)	Endesa, Canary government	Proposed	1.3	2011
Tenerife (Canary Islands)	Endesa, Canary government	Proposed		2011
Total in operation			**54.8**	
Potential total			**77.3**	

Source: Natural Gas Information 2008, IEA, company information.
* 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.

power plants of Endesa and Union Fenosa. The terminal is already planning to double capacity by 2013.

Enagas plans its fourth terminal, a 7 bcm per year facility at El Musel in northern Spain, in 2011. A number of gas-fired power plants are planned in the area. Two new terminals are also planned on the Canary Islands, which are also scheduled for start-up in 2011.

Portugal

Portugal started importing LNG from Nigeria at its sole receiving terminal in 2004. In addition to regasification of 2.4 bcm in 2007, compared to 1.94 bcm sent out in 2006, the terminal shipped out around 2 000 truck loads of LNG to satellite consumption points in the country. According to the energy sector restructuring policy, the ownership of the terminal was transferred from Galp to Ren Atlantico.

United Kingdom

The United Kingdom's only operating onshore LNG receiving terminal at Isle of Grain near London received only 18 cargoes in 2007, compared to 45 in 2006. The second, Teesside Dockside terminal in northeast England, only received a partial, commissioning cargo in February 2007. Low gas prices in the country's market effectively precluded greater LNG imports.

Dragon LNG in Milford Haven in Wales is due to be commissioned in 2008 with an initial capacity of 6.0 bcm per year. Malaysia's Petronas and Centrica terminated a 15-year gas supply agreement at the terminal in 2007. This raises questions about utilisation rates of the terminal, whose capacity is shared equally between BG and Petronas. The even larger South Hook terminal is also due to open in Milford Haven in 2008, as part of the integrated supply chain of the Qatargas 2 mega-train project in Qatar. As pipeline import capacity in the United Kingdom expanded significantly during the past two years, the capacity of the two new terminals is not expected to be used at a high rate in the initial years of operation. Two phase expansions are under construction for the existing Isle of Grain terminal.

ConocoPhillips submitted a planning application to the Stockton Council in Northern England for a terminal in Teesside on behalf of Norsea Pipelines in July 2007.

Table A.7 **LNG terminals in Portugal**

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Sines	Ren Atlantico	Operating	5.5	2004
expansion			3.0	
Total			**8.5**	

Source: Natural Gas Information 2008, IEA, company information.

Table A.8 LNG terminals in the United Kingdom

Terminal	Sponsors (Capacity holders, in case different from sponsors)	Status	Capacity (bcm per year)	Start up
Isle of Grain	National Grid (BP, Sonatrach (2.5 bcm per year each)	Operating	4.9	2005
expansion	(Sonatrach 3.4, GDF 3.3, Centrica 2.4)	Construction	9.1	2008
expansion II	(Iberdrola 2.8, Centrica 2.4, E.ON 1.7)	Construction	6.9	2010
Teesside dockside	Excelerate Energy	Operating	4.0	2007
South Hook I	Qatar Petroleum / ExxonMobil	Construction	10.6	2008
II		Construction	10.6	2009
Dragon LNG	BG, Petronas, 4Gas (BG, Petronas 3 bcm each)	Construction	6.0	2008
expansion	BG, Petronas, 4Gas	Proposed	3.0	2011
Norsea Pipelines (Teesside onshore)	ConocoPhillips, Total, Eni, StatHydro	Proposed	7.3	
Expected total in 2008			**34.6**	
Potential total			**62.4**	

Source: Natural Gas Information 2008, IEA, company information.

Ireland

Shannon LNG announced its plan for a receiving terminal on the west coast of the country in May 2006. Shannon LNG is a wholly owned Irish subsidiary of Hess LNG Limited, which is a joint venture of Hess Corporation and Poten & Partners. Its planning application was approved by Ireland's planning authority, An Bord Pleanala, in early April 2008. The terminal could serve 40% of Ireland's gas demand and could help to reduce Ireland's dependence on imports from the United Kingdom. A new pipeline of about 30 km would be built to connect the terminal to the national pipeline system east of the site.

Table A.9 LNG terminals in Ireland

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Shannon	Hess LNG	Proposed	4.1	2012
Potential total			**4.1**	

Source: Company information.

Turkey

Turkey has imported LNG from Algeria since 1994 and from Nigeria since 1999, only at state-owned Botas' Marmara Ereglisi receiving terminal. In the wake of winter gas supply shortage caused by unstable pipeline imports from the Islamic Republic of Iran early in 2008, gas was also imported at the Aliaga terminal in Izmir. The terminal, which is owned by a private family-owned business, had been idle since its construction in 2002, as the country's legislation at that time did not allow private companies to import LNG.

Greece

Greece's Public Gas Corporation, DEPA, owned by the Greek government (65%) and Hellenic Petroleum (35%), started importing LNG from Algeria in 2000, after being founded in 1988 and starting imports of pipeline gas in 1996. Sendout capacity at its sole LNG receiving terminal on Revithoussa Island was expanded in 2007 from 1.4 bcm to 5.2 bcm per year.

Poland

In January 2008, Polish Oil and Gas (PGNiG) awarded a USD 10.6 million engineering design contract for a 2.5 bcm per year LNG receiving terminal at Swinoujscie, on Poland's northwest Baltic coast, to a Canadian engineering firm SNC Lavalin. The engineering work is expected to take nine months to complete, so that PGNiG hopes to obtain a building permit by the end of 2008. The start-up date is likely to be in 2012 or later. Poland's LNG project is a way to diversify gas supply sources. At

Table A.10 LNG terminals in Turkey

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Marmara Ereglisi	Botas	Operating	6.5	1994
Aliaga, Izmir	Egegaz	Operating	6.0	2006
Total			**12.5**	

Source: Natural Gas Information 2008, IEA, company information.

Table A.11 LNG terminals in Greece

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Revithoussa	DEPA	Operating	5.2	2000
Total			**5.2**	

Source: Natural Gas Information 2008, IEA, company information.

present, more than 90% of the country's imported gas comes from Russia and other former Soviet Union countries. Possible LNG suppliers include Algeria and Qatar.

Croatia

Five companies set up Zagreb-based Adria LNG to develop an LNG import terminal on the north Croatian island of Krk in October 2007. In the new company, E.ON Ruhrgas has a 31.15% stake, followed by OMV and Total with 25.58% each, RWE with 16.69% and Slovenian state-owned Geoplin with 1%. Croatia's state-controlled oil company INA, which had been in prior study groups of the terminal, has also announced plans to join the project. The Adria terminal would have initial capacity of 10 bcm per year, which could be expanded to 15 bcm per year at a later date. Partners say the terminal could enter service in early 2012 if a final investment decision is taken in 2008.

United States

The North American gas market is three times as big as the global LNG market. Around 800 bcm was consumed in North America whereas 236 bcm was traded globally as LNG in 2007. "Only" about 22 bcm of gas was imported into North America as LNG. In two years or so, more than 100 bcm per year of additional import capacity is expected to be in place in North America, particularly concentrated on the Gulf of Mexico. Canada and the Pacific Coast of North America will also have their first operating LNG receiving terminals.

Table A.12 LNG terminals in Poland

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Swinoujscie	PGNiG	Proposed	2.5	2012+
expansion		Proposed	5.0	n.a.
Potential total			**7.5**	

Source: Company information.

Table A.13 LNG terminals in Croatia

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Krk Island	E.ON Ruhrgas, OMV, Total, RWE, Geoplin	Proposed	10	2012
expansion		Proposed	5	n.a.
Potential total			**15**	

Source: Company information.

Table A.14 LNG terminals in the United States

Terminal	Sponsors	Shippers	Status	Capacity (bcm per year)	Start up
Everett	Suez	Suez	Operating	7.3	1971
Lake Charles	Southern Union	BG	Operating	19.6	1982
Elba Island	El Paso	BG, Shell	Operating	8.8	1978
expansion		BG, Shell	Construction	4.2	2010
expansion		BG, Shell	Planned	5.1	2012
Cove Point	Dominon	StatoilHydro, BP, Shell	Operating	11.3	1978
expansion		StatoilHydro	Construction	8.3	2008
Gulf Gateway	Excelerate	Excelerate	Operating	4.9	2005
Northeast Gateway	Excelerate	Excelerate	Operating	4.1	2008
Cameron	Sempra	Sempra, Eni, Merrill Lynch Commodities	Construction	15.5	2008
expansion		Sempra	Planned	11.9	2011
Freeport	Freeport LNG	ConocoPhillips, Dow	Operating	15.5	2008
Sabine Pass	Cheniere	Total, Chevron, Cheniere	Operating	26.9	2008
expansion		Cheniere	Construction	14.5	2009
Golden Pass	Qatar Petroleum, ExxonMobil, ConocoPhillips	RasGas III, Qatargas III	Construction	20.7	2009
Neptune	Suez	Suez	Planned	5.2	2009
Gulf LNG Pascagoula	El Paso, Sonangol of Angola	Angola LNG, Eni	Construction	13.4	2011
Ingleside Energy	Occidental		Planned	10.3	2011+
Corpus Cristi	Cheniere		Planned	26.9	2011+
Browadwater	Shell, TransCanada		Planned	10.3	2011+
Crown Landing	BP		Planned	12.4	2011+
Creole Trail	Cheniere		Planned	34.1	2011+
Port Arthur	Sempra		Planned	15.5	2011+
expansion			Planned	15.5	2014+
Main Pass Energy Hub	Freeport McMoran		Planned	10.3	2012+
Capacity as of 2007				**51.9**	
Capacity to be added in 2008-2009				**110.7**	

Source: Natural Gas Information 2008, IEA, company information.

Currently, five onshore LNG receiving terminals are under construction in the Gulf of Mexico region of the United States. Four of them are scheduled to add more than 90 bcm per year receiving capacity in 2008 and 2009. Except Total at the Sabine Pass terminal and Qatar Petroleum (QP), ExxonMobil and ConocoPhillips at the Golden Pass terminal, most of capacity holders at the new terminals in the Gulf of Mexico region have not secured long-term LNG supply sources. As a result of this, utilisation rates of the terminals are expected to be low at least during the first few years of operation.

Even Qatari LNG marketers are diverting some of the long-term LNG volumes originally intended for the terminals in the United States.

The fifth one under construction in the Gulf of Mexico region, the Gulf LNG Clean Energy terminal at Pascagoula, Mississippi, started construction in February 2008 after the presumed supply source, Angola LNG, made a final investment decision in December 2007.

Excelerate Energy, with its "Energy Bridge" concept, has provided a viable solution to reduce required lead times for LNG imports by installing receiving facilities with its onboard regasification vessels in the United States and United Kingdom. However, the Gulf Gateway and Northeast Gateway terminals in the United States and the company's Teesside dockside regasification terminal in the United Kingdom, have received only a few shipments of LNG, as the global gas price differentials have not justified spot LNG cargoes being diverted to these facilities.

Canada

The first LNG receiving terminal in Canada is being constructed at Canaport's site in St. John, New Brunswick, sponsored by Repsol and Irving Oil with targeted start up in late 2008, and an initial capacity of 10.3 bcm per year. The regasified LNG will be marketed in Canada and the United States northeast markets through the Maritime and Northeast Pipeline (M&NE).

The Gros Cacouna (Cacouna Energy) project of 5.2 bcm per year, backed by PetroCanada and TransCanada, was approved by the regional Quebec government and National Energy Board (NEB) in summer 2007. However, the fate of this terminal plan is uncertain now that it has lost the potential main supply source from the Baltic LNG project in Russia in February 2008 by Gazprom's decision to cancel the project. Trans Quebec and Maritimes Pipeline Inc (TQM Pipeline) halted plans to build a pipeline that would connect the Gros Cacouna terminal with the main transmission system.

The Rabaska partnership consisting of Gaz Metro, Enbridge and Gaz de France (GdF) received a favourable environmental report from a joint federal and provincial review panel in early July 2007 for a 5.2 bcm per year terminal. In May 2008, Russia's Gazprom announced that it would join the terminal project as an additional equity partner. In 2006, Maple LNG, a division of Dutch LNG terminal developing company 4Gas, bought an LNG receiving terminal plan at Goldboro, Nova Scotia, which was originally planned by Keltic Petrochemicals as part of a large petrochemical complex.

Two terminals are planned in British Columbia. The Kitimat project at Bish Cove for 6.2 bcm per year terminal has already acquired necessary regulatory approvals. The project now plans to build an adjacent 250-500 MW CCGT power plant. The WestPac project moved its 5.2 bcm per year receiving terminal site from Ridley Island, near Prince Rupert, to Texada Island further south. It also plans an accompanying 600 MW power plant. The company hopes for start-up in 2013 at the earliest.

Mexico

The Costa Azul terminal, the first LNG receiving terminal in North America's Pacific Coast and the second in Mexico, started operations in April 2008 with an initial capacity of 10.3 bcm per year. However, up to half of volumes (2.5 bcm out of 5 bcm per year) from the Tangguh LNG project in Indonesia initially allocated to this terminal can be diverted to Asian buyers. As the Indonesian project is not expected to start delivery until early 2009, the terminal developer intends to start its operation with spot LNG purchases. Sempra may expand the terminal if sufficient interest from shippers is secured.

The Manzanillo terminal plan by Mexico's state power generator CFE (Comisión Federal de Electricidad) in the central Pacific state of Colima was pushed back several times before Repsol was finally chosen as its LNG supplier in September 2007. The terminal construction and operation contract was awarded in March 2008, after also being postponed several times. CFE said the winning consortium, Japan's Mitsui with Korea's Samsung and Korea Gas (Kogas), offered a regasification fee of

Table A.15 LNG terminals in Canada

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Atlantic Coast				
Canaport	Repsol, Irving Oil	Construction	10.3	2008
Bear Head	Anadarko Petroleum	Halted	10.3	n.a.
Gros Cacouna	PetroCanada, TransCanada	Proposed	5.2	2014+
Rabaska	Gaz Metro, Enbridge, Gaz de France (GdF), Gazprom	Proposed	5.2	2014+
Maple LNG	4Gas, Suntera Canada	Proposed	10.3	2014+
Pacific Coast				
Bish Cove	Kitimat	Proposed	6.3	2014+
Texada Island	WestPac	Proposed	5.2	2015+
Potential total			**52.8**	

Source: Natural Gas Information 2008, IEA, company information.

USD 0.4044 per MBtu. CFE's current ramp-up schedule of the terminal envisages the provision of 1 bcm in the second half of 2011, 2.1 bcm in 2012, 4.1 bcm in 2013 and 5.2 bcm per year from 2014 onwards. Kogas will operate the terminal with a 25% interest, with Mitsui and Samsung 37.5% each. This marks the first operation outside Korea by Kogas, one of the largest LNG importers in the world.

Qatargas will supply Total Gas and Power with 0.95 bcm per year of LNG from 2009, at Mexico's first LNG receiving terminal in Altamira in the Gulf of Mexico, which opened in August 2006, selling gas to state power generator (CFE) under a long-term agreement by the terminal sponsors Shell and Total. The terminal is currently supplied from the two companies' portfolios of LNG. 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 current annual gas demand.

LNG is needed in Mexico to supplement indigenous gas production and reduce dependence on piped gas from the United States. The country's main LNG user, CFE, has taken different approaches to ensure gas from the three LNG terminals, apparently successfully. SITT Energy, a subsidiary of Gulf United Energy and Cia Mexicana de Gas Natural, plans to invest in a proposed LNG terminal in Yucatan Peninsula. The target date for the project is 2011. Another receiving terminal is proposed at Puerto Libertad, Sonora, in the Gulf of California by El Paso and DKRW Energy of the United States.

Table A.16 LNG terminals in Mexico

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Atlantic Coast				
Altamira	Shell, Total, Mitsui	Operation	5.2	2006
Yucatan	SITT Energy	Proposed	5.0	2011
Pacific Coast				
Costa Azul, Baja California	Sempra	Operation	10.3	2008
expansion		Proposed	10.3	2010+
Manzanillo, Colima	Kogas, Samsung, Mitsui	Planned	5.2	2011
Puerto Libertad, Sonora	El Paso, DKRW Energy	Proposed	10.3	2015
Potential total			**46.3**	

Source: Natural Gas Information 2008, IEA, company information.

Chile

Chile has plans to import LNG into its central and northern regions to reduce dependence on piped imports from Argentina, after the pipeline supply has been reduced repeatedly since 2004. BG was chosen to build and supply a planned terminal in the central region. While the terminal was originally planned to open in 2008, it was now scheduled to start operation in 2009 due to a delay in EPC contracting. The project is to build a small 14 000 m³ tank that would allow the facility to operate before two 160 000 m³ tanks are built. Suez Energy International and Chile's main copper producer Codelco started building a terminal at Mejillones, in the country's northern mining region, in March 2008. Phase one will have an LNG vessel moored for storage, as well as a jetty and onshore regasification plant. A 160 000 m³ tank is planned for the second stage in 2012.

Brazil

Brazil's Petrobras is developing two LNG import terminals using regasification vessels 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 2 bcm per year at Pecém, Ceará, by as early as August 2008 and 4.8 bcm per year for Guanabara Bay, near Rio de Janeiro, in 2009. The Pecém terminal will be the first floating storage and regasification unit (FSRU) LNG terminal in the world while the Guanabara Bay terminal will employ a shuttle and regasification vessel (SRV). The company is also considering building a third terminal and plans to have 11 bcm per year of regasification capacity by 2012.

Petrobras announced in March 2008 a three-year LNG purchase agreement with Shell without disclosing volumes and other terms. In addition to another LNG purchase agreement that the company claims to have signed in December 2007, it has also signed master spot purchase agreements with Nigeria LNG, Algeria's Sonatrach, France's Suez, and Spain's Endesa. The company intends to use LNG in the country's dry season to compensate for lower output of hydro power and avoid months of higher LNG demand in other markets in the world. Future imports by the country are highly dependent on how the country can develop two recent major hydro carbon resource finds in the offshore Santos Basin: Tupi and Jupiter.

Table A.17 LNG terminals in Chile

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Quintero, Central	BG (40%), Empresa Nacional de Petroleo, Metrogas, Endesa (20% each)	Construction	3.4	2009
Mejillones, Northern mining region	Codelco, Suez	Construction	1.8	2010
Potential total			**5.2**	

Source: Company information.

Argentina

The first LNG regasification terminal in Latin America at Bahía Blanca was opened in May 2008 to cope with natural gas shortages in the country. This is a dockside terminal, using onboard regasification vessels. As the country has significant undeveloped gas reserves, the terminal could be only a short-term solution until domestic gas production increases and/or another permanent LNG terminal is completed.

Japan

Japan is currently the largest importer of LNG in the world and is expected to remain so well into the future. The country has 28 LNG receiving terminals nominally capable of regasifying 230 bcm per year of LNG, used by 17 companies. Fuel switching in the industrial sector and nuclear problems supported an increase in LNG imports in 2007 (+8.5 %) to 93 bcm from 12 exporting countries. Another notable point in the year was increasing imports from the Atlantic Basin, which represented 43% of the year's incremental imports, compared to a third in 2006 and no spot cargoes from the Atlantic in 2005. Japan imported LNG even from Norway for the first time in March 2008.

One interesting development in recent years in the country's LNG business is transportation of LNG by coastal tankers, which are much smaller than ocean-going LNG tankers. There are currently four such secondary LNG receiving terminals (Okayama, Takamatsu, Hakodate and Hachinohe) in places that are not connected by transmission pipelines and that instead receive LNG from larger receiving terminals. The country has also five LNG receiving terminals (Fukuoka, Hatsukaichi, Kagoshima, Shin Minato, and Nagasaki) that are served by smaller ocean tankers but larger than the coastal tankers.

Relatively large-scale gas-fired power generation plants are now operated and planned by companies other than incumbent power generators in the country. The Kawasaki Natural Gas Power

Table A.18 **LNG terminals in Brazil and Argentina**

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Pecém, Ceará, Northeast	Petrobras	Construction	2.0	2008
Guanabara Bay, Rio de Janeiro	Petrobras	Construction	4.8	2009
Undisclosed location	Petrobras	Proposed	4.5	2012
Bahía Blanca	Repsol YPF	Operation	1.5	2008
Potential total			**12.8**	

Source: Company information.

station with 847 MW is scheduled to start operations in 2008, followed by the Senboku Natural Gas Power station with 1 109 MW in 2009 and the Ohgishima Power station with 1 221 MW in 2010.

Korea

Korea Gas Corporation (Kogas) is focusing on procuring more long-term volumes of LNG to cope with future demand growth and shortfalls to be caused by some contract expirations.

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 the current 5.5 mcm to 8.3 mcm (+56%) by 2013. Kogas has also signed an initial pact with Oman's state gas company to build and operate two 200 000 m³ 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.

Korea has four LNG receiving terminals: three operated by Kogas (Pyeong-Taek, In-Chon and Tong-Yeong), and one by Posco (Gwangyang). Kogas plans to have another terminal by 2012. In addition, the Ministry of Construction and Transportation finally approved GS Caltex's application to build a new terminal in an industrial area in the south of the country in 2007.

Recently Kogas has been active in expanding LNG activities overseas. It is a member of consortia of companies that have been awarded contracts to build LNG receiving terminals in Mexico and

Table A.19 LNG terminals in Korea

Terminal	Sponsors	Status	Capacity (bcm per year)	Storage capacity (m³)	Start up
Pyeong-Taek	Kogas	Operating	26.1	1 000 000	1986
Pyongtaek 2	Kogas	Operating	4.3	280 000	2007
expansion	Kogas	Construction	12.9	680 000	2008-2012
In-Chon	Kogas	Operating	37.9	2 480 000	1996
expansion	Kogas	Construction	12.2	400 000	2009
Tong-Yeong	Kogas	Operating	15.3	1 400 000	2002
expansion	Kogas	Construction	6.4	1 000 000	2009
Gwangyang	Posco	Operating	2.4	300 000	2005
Boryung	GS Caltex	Planned	2.7		2012
Samcheok	Kogas	Proposed		1 000 000	2012
Potential total			**120.2**	**8 540 000**	

Source: Natural Gas Information 2008, IEA, company information.

Thailand. It is also to provide technical assistance to China's planned second LNG receiving terminal in Fujian.

There is a plan to supply a relatively small amount of LNG to an industrial complex in North Korea from the In-Chon terminal in Korea by tank truck starting late 2008 or early 2009.

Chinese Taipei

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 12% in 2007 with an import total of 11.4 bcm, compared with an average annual 10% growth experienced since 2001. Much of the growth was supported by incremental purchase from the Atlantic basin LNG suppliers. 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 from 2008, with 2.3 bcm per year dedicated to the 4.27 GW Tatan power plant. Power generation accounts for three quarters of Chinese Taipei's gas demand. The gas for the Tatan power plant would be supplied through CPC's Taichung terminal under construction in the central part of the island, targeted for completion in 2008. Although the terminal received a cool-down cargo in October 2007, commercial operation has been delayed as the pipeline construction was disrupted by typhoons and is not expected to be completed until the third quarter of 2008.

China

China's first LNG receiving terminal in Guangdong started to import cargoes in May 2006. The second Fujian terminal received its first cargo in April 2008. The operator of the terminals, state-controlled China National Offshore Oil Corporation (CNOOC), is constructing an additional receiving terminal in Shanghai, which is majority-owned by Shanghai utility company, Shenergy. This will be the last receiving terminal to be built by the end of this decade in the country. Thus, the country's LNG business will be dominated by CNOOC up to 2010. However, the biggest gas producer in China, PetroChina has been active in procuring LNG supply for the next decade, securing deals with LNG suppliers in Australia and Qatar.

Table A.20 LNG terminals in Chinese Taipei

Terminal	Sponsors	Status	Capacity (bcm per year)	Storage capacity (m^3)	Start up
Yung-An	CPC	Operating	24.3	690 000	1990
Taichung	CPC	Construction	4.1	480 000	2008
Potential total			**28.4**	**1 370 000**	

Source: Natural Gas Information 2008, IEA, company information.

Table A.21 China's LNG receiving terminal projects

[Sponsor], project	**Capacity (bcm per year)**	**Status, start date**	**Supply source**
[CNOOC]			
Guangdong	5.0 + 3.4	Operating, 2006	NWS, Qatar + spot
Fujian	3.5 + 3.3	Operating, 2008	Tangguh
Shanghai	4.1	Construction, 2009	Malaysia LNG Tiga
Zhejiang, Ningbo	4.1	2011+	
[PetroChina]			
Liaoning, Dalian	4.2	Construction, 2011	Qatargas 3 and 4
Jiangsu, Rudong	4.8	2011+	Gorgon or Browse
Hebei, Tangshan	4.1	2011+	
Shenzhen, Guangdong	4.1	2011+	
[Sinopec]			
Shandong, Qingdao	4.1	n.a. (2012+)	Iran?
[CLP (+ ExxonMobil)]			
Hong Kong Black Point	3.5	2013	BG, others
Total capacity in 2010	16-20		
Total capacity in 2015	**40-48**		

Source: Company information, media reports

Hong Kong's China Light & Power (CLP) has also secured long-term LNG supply from BG for the planned import terminal. Castle Peak Power Co. (Capco), a 40-60 CLP joint venture with Exxon Mobil, has a contract since 1996 until 2015 to purchase gas from the CNOOC-operated Yacheng 13-1 field near Hainan Island for its main 2.5 GW Black Point power plant.

CNOOC purchased spot LNG cargoes for the first time in 2007. Total LNG imports in the year were 4 bcm, including 3.4 bcm from the North West Shelf venture from Australia under a long-term purchase agreement and 0.6 bcm of spot cargoes. The Chinese company expects to double spot purchases in 2008.

India

Petronet, India's first and largest LNG importer, buys 6.8 bcm per year 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 of the long-term purchase will increase to 10.2 bcm per year in 2009. Petronet plans another terminal in Kochi, in the state of Kerala, targetting an initial capacity of 3.4 bcm per year in 2011, eventually expandable to 6.8 bcm per year. Petronet is also expanding capacity at the Dahej terminal from current 8.8 bcm per year to 17 bcm per year by summer 2008.

The company has said it hopes to sign a purchase agreement for 3.4 bcm per year from ExxonMobil's share of LNG from Australia's Gorgon project. Petronet also secured another 1.7 bcm over the period from July 2007 to August 2008 from RasGas. This volume is sold to the Dabhol power plant in the western state of Maharashtra through the Dahej-Dabhol pipeline until the 6.8 bcm per year Dabhol LNG import terminal is ready in 2009.

The 3.4 bcm per year Hazira terminal, also on India's west coast, owned by Shell (74%) and Total (26%), is operated solely with spot cargoes. The terminal has been active since the second half of 2006, after an inactive first year of operation.

The two terminals received 10.6 bcm of LNG in total in 2007, compared to 7.2 bcm in 2006.

Thailand

Thailand's state-owned PTT confirmed a plan to construct a receiving terminal on the east coast of the country by June 2011, signing up Iranian supply of 4.1 bcm per year in 2006. As the progress of the Iranian supply is uncertain, PTT signed a non-binding Heads of Agreement to purchase 1.4 bcm per year of LNG from Qatar in

Table A.22 LNG terminals in India

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Dahej	Petronet	Operating	8.9	2004
expansion	Petronet	Construction	8.2	2008
Hazira	Shell, Total	Operating	3.7	2005
debottlenecking	Shell, Total	Ongoing	1.1	2008
Ratnagiri (Dabhol)			7.5	2009
Kochi	Petronet	Planned	3.4	2011
Potential total			**32.7**	

Source: Natural Gas Information 2008, IEA, company information.

February 2008. A Korean consortium of GS Engineering and Construction, Hanyang, Daewoo Engineering and Kogas was awarded a contract to build the planned terminal in January 2008. Thailand's current gas demand of 31 bcm per year is forecast to be 52 bcm in 2011 and 72 bcm in 2021. Thailand wants LNG to diversify away from piped gas from Myanmar. Major potential users of regasified LNG include the state-owned Electricity Generating Authority (EGAT).

Singapore

Singapore decided to go ahead with its plan for a 4.1 bcm per year LNG terminal plan on the industrial Jurong Island in early August 2006, citing security of gas supply as the main driver to complement the current 8 bcm per year pipeline gas imported from Indonesia and Malaysia, which is used to generate 80% of the country's power supply. In order to facilitate the LNG import plan, the government issued a moratorium on new pipeline gas imports in 2006. The country's gas demand is expected to rise as power generators switch from coal and oil to gas; in addition, new petrochemical plants are planned. Terminal developer and prospective operator PowerGas announced in February 2008 that five groups were short-listed for the LNG aggregator role with an exclusive licence to import up to 4.1 bcm per year of LNG and sell the sendout in the country or re-export it. Among the five candidates, BG Group was chosen for the aggregator role in April 2008. The government has introduced a concessionary 5% tax rate on qualifying income derived from LNG trading as an incentive for the aggregator.

Indonesia

Indonesia's state-run gas distributor, Perusahaan Gas Negara (PGN) has plans to construct LNG receiving terminals in East and West Java and Northern Sumatra to cope with increasing domestic energy demand. Start up targets are set at 2011-2012. PGN initially floated the idea of constructing a receiving terminal in Java in 2004, after a feasibility study funded by the Japan Bank for International Cooperation (JBIC). PGN has expressed interest in buying LNG from the existing Bontang LNG plant in East Kalimantan and the Tangguh LNG project in Papua, which is to start LNG production in late 2008 or early 2009, to supply the terminals. In March 2008, the country's upstream regulator BPMigas said the government had decided to allocate 2 bcm per year of LNG from the existing Bontang LNG plant in East Kalimantan and 1.4 bcm per year from a proposed third train at the Tangguh plant in Papua to the West Java terminal, although gas producers' consents are needed for the idea.

Pakistan

State-owned Sui Southern Gas has been directed by the government to oversee the Mashal LNG project in Karachi, which is designed to address the country's projected gas shortage of 5 bcm per year in 2010. The company received bids from Royal Dutch Shell and a consortium comprising Dutch 4Gas and two local companies to build this proposed terminal and provide long-term supplies in December 2007. The appointed developer is expected to be announced in 2008 to manage the supply, transportation, and storage of the project.

Philippines

State-owned Philippine National Oil Co. (PNOC) has a plan to build an LNG receiving terminal in Bataan. In 2007 Japan's Marubeni conducted a technically feasible for PNOC to build a 1.9 bcm per year terminal, as well as associated gas-fired power plants with minimum capacity of 1 GW.

Kuwait

State Kuwait Petroleum Corp. (KPC) said in February 2008 that it was in talks with suppliers, including Qatar, on securing LNG –to be delivered exclusively in the six summer months of the year, equating to 2.6-3.9 bcm per year for a period of up to five years. Excelerate won a contract to provide an on-board regasification vessel and onshore facilities for the planned terminal at Mina al-Ahmadi.

Dubai, United Arab Emirates

Dubai's state-owned gas supply company, Dubai Supply Authority (Dusup), announced in April 2008 that it plans to build a 4.1 bcm per year floating regasification terminal in the Jebel Ali port. Norwegian shipping company Golar LNG will provide one of its existing LNG ships to be converted into a floating storage and regasification unit (FSRU) for the terminal. Shell and Qatar Petroleum (QP) are expected to supply 2 bcm per year from their Qatargas IV project.

Table A.23 **LNG terminals in Thailand, Singapore, Indonesia, Pakistan, and Philippines**

Terminal	Sponsors	Status	Capacity (bcm per year)	Start up
Map Ta Phut, Thailand	PTT, Electricity Generating, Electricity Generating Authority (EGAT)	Planned	6.8	2011
Jurong Island, Singapore	PowerGas	Planned	4.1	2012
East Java, Indonesia	PGN	Proposed	2.1	2011
North Sumatra, Indonesia	PGN	Proposed	2.1	2011
West Java, Indonesia	PGN	Proposed	2.1	2011
Mashal, Karachi, Pakistan	Sui Southern	Proposed	4.8	2011
Battan, Philippines	PNOC	Proposed	1.9	2012
Potential total			**23.9**	

Source: Natural Gas Information 2008, IEA, company information.

Table A.24 LNG regasification terminals in the world

Country	Terminal	Capacity bcm/y	Capacity 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
	Ishikari			180 000	2013	Proposed
	Joetsu	4.0	2.9	360 000	2013	Proposed
	Kagoshima	0.3	0.2	86 000	1996	Operation
	Kawagoe	7.5	5.5	480 000	1997	Operation
	expansion			360 000	2011	Planned
	Mizushima	0.8	0.6	160 000	2006	Operation
	expansion	1.4	1.0	160 000	2012	Planned
	Nagasaki	0.2	0.1	35 000	2003	Operation
	Naoetsu	0.7	0.5	360 000	2013	Proposed
	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	Construction
	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
	Shin-Sendai				2016	Proposed
	Sodegaura	39.9	29.3	2 660 000	1973	Operation
	Sodeshi	1.2	0.9	177 200	1996	Operation
	expansion			160 000	2010	Planned
	Tobata	9.3	6.8	480 000	1977	Operation
	Wakayama				n.a.	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
	Pyongtaek 2	4.3	3.2	280 000	2007	Operation
	expansion 1	4.3	3.2	280 000	2008	Construction
	expansion 2	4.3	3.2	200 000	2010	Planned
	expansion 3	4.3	3.2	200 000	2012	Planned

Table A.24 LNG regasification terminals in the world (continued)

Korea (cont.)	In-Chon	37.9	27.9	2 480 000	1996	Operation
	expansion	12.2	8.9	400 000	2009	Construction
	Tong-Yeong	15.3	11.2	980 000	2002	Operation
	expansion 1			420 000	2006	Operation
	expansion 2	6.4	4.7	1 000 000	2009	Construction
	Gwangyang	2.4	1.8	300 000	2005	Operation
	Boryeong	2.7	2.0		2012	Proposed
	Samcheok			1 000 000	2012	Proposed
Chinese Taipei	Yung-An	24.3	17.9	690 000	1990	Operation
	Taichung	4.1	3.0	480 000	2008	Construction
China	Guangdong Dapeng	5.0	3.7	320 000	2006	Operation
	expansion 1			160 000	2007	Operation
	expansion 2	3.4	2.5	160 000	2009	Construction
	Fujian	3.5	2.6	320 000	2008	Operation
	expansion	3.3	2.4	320 000	2011	Construction
	Shanghai LNG	4.1	3.0	495 000	2009	Construction
	Liaoning, Dalian	4.2	3.1		2011	Planned
	Zhejiang, Ningbo	4.1	3.0		2011+	Planned
	Hong Kong Black Point	3.5	2.6		2013	Planned
	Shandong, Qingdao	4.1	3.0		n.a.	Planned
	Jiangsu, Rudong	4.8	3.5		2011+	Planned
	Hebei, Tangshan	4.1	3.0		2011+	Planned
	Shenzhen, Guangdong	4.1	3.0		2011+	Planned
India	Dahej	8.9	6.5	320 000	2004	Operation
	expansion	8.2	6.0	320 000	2008	Construction
	Hazira	3.7	2.7	320 000	2005	Operation
	debottlenecking	1.1	0.8		2008	Construction
	Ratnagiri (Dabhol)	7.5	5.5	480 000	2009	Construction
	Kochi	3.4	2.5	310 000	2011	Planned
Singapore	Jurong Island	4.1	3.0	300 000	2012	Planned
Thailand	Map Ta Phut	6.8	5.0	360 000	2011	Planned
Indonesia	East Java	2.1	1.5		2011	Proposed
	North Sumatra	2.1	1.5		2011	Proposed
	West Java	2.1	1.5		2012	Proposed
Pakistan	Marshal	4.8	3.5	300 000	2011	Proposed
Philippines	Bataan	1.9	1.4		2012	Proposed
Dubai	Jebel Ali	4.1	3.0		2010	Proposed
Kuwait	Mina al-Ahmadi	3.0	2.2		2009	Proposed
Mexico (West)	Costa Azul	10.3	7.6	320 000	2008	Operation
	Costa Azul expansion	10.3	7.6		2010+	Proposed
	Manzanillo	5.0	3.7	300 000	2011	Planned
	Puerto Libertad, Sonora	10.3	7.6	540 000	2015	Proposed
Canada (West)	Kitimat LNG	6.3	4.6	160 000	2014	Planned

Table A.24 LNG regasification terminals in the world (continued)

Canada (West)	WestPac	5.2	3.8		2015	Proposed
Chile	Quintero, Central	3.4	2.5	14 000	2009	Construction
				320 000	2012	Construction
	Mejillones, Northern mining region	1.8	1.3		2010	Construction
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	2009	Construction
	Dunkerque	6.0	4.4		2012	Planned
	expansion	6.0	4.4		n.a.	Proposed
	Le Havre (Antifer)	9.0	6.6	200 000	2012	Planned
	Bordeaux (Le Verdon)	9.0	6.6	462 000	2013	Planned
	Fos Faster (Shell)	8.0	5.9		2015	Proposed
	Bordeaux (Le Verdon)	4.0	2.9		n.a.	Proposed
Spain	Barcelona	17.3	12.7	540 000	1969	Operation
	expansion	1.3	1.0		2008	Construction
	expansion 7			150 000	2010	Construction
	expansion 8			150 000	2011	Planned
	Huelva	13.6	10.0	460 000	1988	Operation
	expansion 5			150 000	2010	Construction
	Cartagena	9.9	7.3	287 000	1989	Operation
	expansion 4	1.3	1.0	150 000	2008	Construction
	expansion 5			150 000	2011	Planned
	Bilbao	8.0	5.9	300 000	2003	Operation
	expansion 3	2.5	1.8	150 000	2012	Planned
	expansion 4			150 000	?	Planned
	Sagunto	6.0	4.4	300 000	2006	Operation
	expansion	1.8	1.3		2008	Construction
	expansion 3			150 000	2009	Planned
	expansion 4			150 000	n.a.	Planned
	Mugardos (El Ferrol)	3.6	2.6	300 000	2007	Operation
	Mugardos expansion	3.6	2.6		2013	Proposed
	El Musel	7.0	5.1	300 000	2011	Planned
	Gran Canaria	1.3	1.0	150 000	n.a.	Planned
	Tenerife			150 000	n.a.	Planned
Portugal	Sines	5.5	4.0	240 000	2004	Operation
	expansion	3.0	2.2		2009	Proposed
Italy	Panigaglia	3.5	2.6	100 000	1969	Operation
	Panigaglia expansion	4.5	3.3		2010+	Planned
	Rovigo offshore	8.0	5.9	250 000	2008	Construction
	Livorno offshore	3.8	2.8	137 500	2011	Construction
	Brindisi	8.0	5.9	320 000	n.a.	Suspended
	Empedocle, Sicily	8.0	5.9		2012	Proposed

Table A.24 LNG regasification terminals in the world (continued)

Italy (cont.)	Le Marche	5.0	3.7		2014+	Proposed
	Rosignano, Toscana	8.0	5.9		n.a.	Proposed
	Taranto, Puglia	8.0	5.9		n.a.	Proposed
	Zaule/Trieste, Friuli	8.0	5.9		n.a.	Proposed
	Monfalcone, Friuli	8.0	5.9		n.a.	Proposed
	Gioia Tauro, Calabria	12.0	8.8		n.a.	Proposed
	Priolo Augusta, Siciliy	8.0	5.9		n.a.	Proposed
Belgium	Zeebrugge	4.5	3.3	261 000	1987	Operation
	expansion 1	4.5	3.3	140 000	2008	Operation
	expansion 2I	9.0	6.6		2015	Planned
Netherlands	Rotterdam (Gate)	9.0	6.6	360 000	2011	Construction
	expansion	7.0	5.1	120 000	2014	Planned
	Rotterdam (LionGas)	9.0	6.6		2011	Planned
	Rotterdam (offshore)				2010	Proposed
	Eemshaven	10.0	7.4		2011	Planned
Germany	Wilhelmshaven	10.0	7.4	320 000	2011	Planned
	Wilhelmshaven GasPort	4.0	2.9		2010	Proposed
Poland	Swinoujscie	2.5	1.8		2012+	Planned
United Kingdom	Isle of Grain	4.9	3.6	200 000	2005	Operation
	Isle of Grain expansion 1	9.1	6.7	370 000	2008	Construction
	Isle of Grain expansion 2	6.9	5.0	190 000	2010	Planned
	Teesside	4.0	2.9		2007	Operation
	South Hook I	10.6	7.8	465 000	2008	Construction
	South Hook II	10.6	7.8	310 000	2009	Construction
	Dragon LNG	6.0	4.4	336 000	2008	Construction
	Dragon LNG expansion	3.0	2.2	168 000	2011	Proposed
	Teesside (ConocoPhillips)	7.3	5.4	380 000	2012+	Proposed
Ireland	Shannon	4.1	3.0	800 000	2012	Planned
Turkey	Marmara Ereglisi	6.5	4.8	255 000	1994	Operation
	Aliaga, Izmir	6.0	4.4	280 000	2006	Operation
Greece	Revithoussa	1.4	1.0	130 000	2000	Operation
	expansion	3.8	2.8		2007	Operation
Croatia	Krk Island	8.0	5.9		2012	Proposed
United States (East)	Everett	7.3	5.4	155 000	1971	Operation
	Lake Charles	19.6	14.4	425 000	1982	Operation
	Elba Island	8.8	6.5	338,720	1978	Operation
	expansion 2	4.2	3.1	160 000	2010	Construction
	expansion 3	5.1	3.7	160 000	2012	Planned
	Cove Point	11.3	8.3	485 000	1978	Operation
	expansion	8.3	6.1	320 000	2008	Construction
	Gulf Gateway	4.9	3.6		2005	Operation

Table A.24 LNG regasification terminals in the world (continued)

United States (East) (cont.)	Northeast Gateway	4.1	3.0		2008	Operation
	Cameron	15.5	11.4	480 000	2008	Construction
	expansion	11.9	8.7	160 000	2011	Planned
	Freeport	15.5	11.4	320 000	2008	Operation
	Sabine Pass	26.9	19.8	480 000	2008	Operation
	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
	Gulf LNG Pascagoula	13.4	9.8	320 000	2011	Construction
	Ingleside Energy	10.3	7.6	320 000	2011+	Planned
	Corpus Cristi	26.9	19.8	480 000	2011+	Planned
	Gulf Landing	10.3	7.6		2011+	Abandoned
	Broadwater	10.3	7.6		2011+	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
	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
	expansion			160 000	2009	Planned
	Bear Head	10.3	7.6	360 000	n.a.	Halted
	Gros Cacouna	5.2	3.8		2014+	Planned
Maple LNG	Rabaska LNG	5.2	3.8		2014+	Planned
	Maple LNG	10.3	7.6	480 000	2014+	Planned
Dominican Republic	Punta Caucedo	2.4	1.8	160 000	2003	Operation
Argentina	Bahía Blanca	1.5	1.1		2008	Operation
Brazil	Pecém, Ceará, Northeast	2.0	1.5		2008	Construction
	Guanabara Bay	4.8	3.5		2009	Construction
Operational total	**as of March 2008****	**550.6**	**404.0**	**27 879 920**		**Operation**
Expected	**in end 2010**	**845.3**	**620.6**	**39 177 420**		
Proposed total		**1 378.7**	**1 012.6**	**53 907 420**		

*as of April 30, 2008.

**does not include the Costa Azul, Sabine Pass, Freeport, Northeast Gateway, Bahía Blanca and Fujian terminals that started operations after 1 April 2008.

ANNEX B: LNG LIQUEFACTION PLANTS

Table B.1 LNG liquefaction plants

Country	Project	Location	Capacity bcm/y	mtpa	Start	Status
Indonesia	Bontang A-H Trains	East Kalimantan	30.3	22.30	1977	Operation
	Arun	North Smatra	9.3	6.80	1978	Operation
	Tangguh LNG	Bintuni Bay, Papua	10.3	7.60	2008	Construction
	Donggi	Central Sulawesi	2.7	2.00	2012	Proposed
	Masela		4.1	3.00	2014	Proposed
Malaysia	MLNG (Satu [I])	Bintulu, Sarawak	11.0	8.10	1983	Operation
	MLNG Dua (II)	Bintulu, Sarawak	10.6	7.80	1995	Operation
	debottlenecking		1.8	1.3	2009	Construction
	MLNG Tiga (III)	Bintulu, Sarawak	9.3	6.80	2003	Operation
Brunei	Brunei LNG	Lumut	9.8	7.20	1972	Operation
Myanmar			4.8	3.50		
Australia	North West Shelf (1-4)	Burrup Peninsula	16.2	11.90	1989	Operation
	North West Shelf Train 5	Burrup Peninsula	6.0	4.40	2008	Construction
	Darwin LNG	Point Wickham	4.5	3.30	2006	Operation
	Gorgon	Barrow Island	20.4	15.00	2014	Proposed
	Gorgon expansion	Barrow Island	13.6	10.00		Proposed
	Wheatstone		6.8	5.00	2015	Proposed
	Pluto	Burrup Peninsula	6.5	4.80	2010	Construction
	Pluto 2	Burrup Peninsula	6.5	4.80	2012	Proposed
	Prelude	Floating	4.8	3.50	2012	Proposed
	Ichthys	Kimberly	11.4	8.40	2013	Proposed
	Browse Basin		20.4	15.00	2014	Proposed
	Gladstone LNG (GLNG) (CSM 1)	Glatstone	5.4	4.00	2015+	Proposed
	Gladstone CSM 2	Glatstone	5.4	4.00	2015+	Proposed
	Gladstone CSM 3	Glatstone	0.7	0.50	2015+	Proposed
	Gladstone CSM Fishermans Landing	Glatstone	1.8	1.30	2015+	Proposed
	Scarborough		8.2	6.00	2015+	Proposed
	Greater Sunrise (Timor Sea)		6.8	5.00	2015+	Proposed
Papua New Guinea	Liquid Niugini Gas		6.8	5.00	2015	Proposed
	PNG LNG	Port Moresby	8.6	6.30	2013	Proposed
Russia	Sakhalin II	Prigorodnoye	13.1	9.60	2008	Construction
	expansion	Prigorodnoye	6.5	4.80	2014	Proposed
Alaska	Kenai LNG	Cook Inlet	2.0	1.50	1969	Operation
Peru	Peru LNG	Pampa Melchorita	6.0	4.40	2010	Construction
Qatar	Qatargas	Ras Laffan	13.5	9.90	1997	Operation
	RasGas	Ras Laffan	9.0	6.60	1999	Operation
	RasGas II (Trains 3-4)	Ras Laffan	12.8	9.40	2004	Operation
	RasGas II (Train 5)	Ras Laffan	6.4	4.70	2007	Operation
	Qatargas II (Train 4)	Ras Laffan	10.6	7.80	2008	Construction
	Qatargas II (Train 5)	Ras Laffan	10.6	7.80	2009	Construction
	Qatargas III (Train 6)	Ras Laffan	10.6	7.80	2010	Construction

Table B.1 LNG liquefaction plants (continued)

Qatar (cont.)	Qatargas IV (Train 7)	Ras Laffan	10.6	7.80	2011	Construction
	RasGas III (Train 6)	Ras Laffan	10.6	7.80	2009	Construction
	RasGas III (Train 7)	Ras Laffan	10.6	7.80	2010	Construction
Oman	Oman LNG	Qalhat	9.8	7.20	2000	Operation
	Qalhat LNG	Qalhat	4.9	3.60	2006	Operation
Abu Dhabi	Abu Dhabi Gas Liquefaction Co (Adgas)	Das Island	7.9	5.80	1977	Operation
Yemen	Yemen LNG (Train 1)	Bal Haf	4.6	3.40	2008	Construction
	Yemen LNG (Train 2)	Bal Haf	4.6	3.40	2009	Construction
Iran	Pars LNG		13.6	10.00	2014	Proposed
	Iran LNG	Bandar Tombak	10.9	8.00	2015	Proposed
	Persian LNG		13.6	10.00	2015	Proposed
	Qeshm		1.6	1.15	2015	Proposed
	North Pars		6.8	5.00	2015	Proposed
	Golshan - Ferdos		27.2	20.00	2015	Proposed
	South Pars 14		6.1	4.50	2015	Proposed
Algeria	Skikda GL1 KII	Skikda	4.3	3.13	1972	Operation
	Arzew GL4Z	Arzew	1.5	1.10	1964	Operation
	Arzew GL1Z	Arzew	11.2	8.20	1978	Operation
	Arzew GL2Z	Arzew	10.9	8.00	1981	Operation
	Gassi Touil	Arzew	5.4	4.00	2012	Proposed
	Skikda	Skikda	6.1	4.50	2011	Construction
Libya	Marsa el Brega	Marsa el Brega	1.0	0.75	1970	Operation
	Marsa el Brega	Marsa el Brega	3.3	2.40	2010+	Proposed
	Mellitah		5.2	3.80	2016	Proposed
Egypt	Segas	Damietta	6.5	4.80	2005	Operation
	Segas Train 2	Damietta	7.2	5.30	2013	Proposed
	Egyptian LNG 1	Idku	4.9	3.60	2005	Operation
	Egyptian LNG Train 2	Idku	4.9	3.60	2005	Operation
	Egyptian LNG Train 3	Idku	4.9	3.60	2013	Proposed
Nigeria	NLNG 1-2	Bonny Island	9.0	6.60	1999	Operation
	NLNG Trains 3	Bonny Island	4.5	3.30	2002	Operation
	NLNG Plus T4-5	Bonny Island	11.2	8.20	2006	Operation
	NLNG Train 6	Bonny Island	5.6	4.10	2008	Operation
	NLNG Seven Plus T7	Bonny Island	10.9	8.00	2012	Proposed
	NLNG Seven Plus T8	Bonny Island	10.9	8.00	2016	Proposed
	Brass LNG	Baylesa	13.6	10.00	2013	Proposed
	Olokola LNG (OK LNG)	Olokola	15.0	11.00	2014	Proposed
	Southeast LNG	Boony Island	6.5	4.80	2018	Proposed
	Repsol-Gas Natural		9.5	7.00	2018	Proposed
Equatorial Guinea	EG LNG	Bioko Island	4.6	3.40	2007	Operation
	EG LNG Train 2	Bioko Island	6.0	4.40	2012	Proposed
Angola	Angola LNG	Soyo	7.1	5.20	2012	Construction

Table B.1 LNG liquefaction plants (continued)

	Angola LNG Train 2	Soyo	7.1	5.20	2015	Proposed
Norway	Snøhvit	Melkoya Island	5.6	4.10	2007	Operation
Russia	Baltic LNG	Ust-Luga	6.8	5.00	n.a.	Canceled
	Shtokman LNG	Murmansk	10.2	7.50	2014	Proposed
	expansion II		10.2	7.50	2018	Proposed
	expansion III		20.4	15.00	2022	Proposed
Trinidad	Atlantic LNG 1	Point Fortin	4.5	3.30	1999	Operation
	Atlantic LNG T2/3	Point Fortin	9.0	6.60	2002	Operation
	Atlantic LNG T4	Point Fortin	7.1	5.20	2005	Operation
	Train 5		7.1	5.20	2013	Proposed
Venezuela	Gran Mariscal		6.4	4.70	2015	Proposed
Operational total	**as of March 2008**		**267.73**	**196.78**		
Proposed total			**795.14**	**584.43**		

ANNEX C: INVESTMENT AND FINANCE FOR RECENT LNG PROJECTS

Table C.1 Investment and finance for recent LNG projects

Project (Operation start) (Finance status)	Investment amount production capacity unit Cost*2	Finance	Amount USD million	Maturity year month	Pre- completion interest	Post-completion interest	Type*3
Indonesia Tangguh	USD 6.95 billion	JBIC	1 200	15y	L+19bp	L+19bp	SG
(2008)	7.6 mtpa	SL*4	1 066	15y	*5	L+22.4bp	SG
(signed Nov 2006)	USD 914	SL	884	12y		na	SG
		ADB	350	na		na	SG
		Equity	3 452				
Malaysia LNG Tiga	USD 1.87billion	JBIC	651	13y		na	SG
(2003)	6.8 mtpa	SL	165	8y6m		L+55	SG
(signed Apr 2001)	USD 275	Equity	1 054				
Australia Darwin	USD 1.5billion	JBIC	380	14y	na	na	SG
(2006)	3.3 mtpa						
	USD 455						
Australia NWS (T5)	USD 2.5 billion	no external finance					
(2008)	4.4 mtpa						
	USD 568						
Australia Pluto	AUD 12 billion (including	JBIC	1 000	15y	na	na	SG
(2010)	upstream)	SL	500	5y	na	na	
	4.8mtpa	Equity	8 500				
Oman Qalhat	USD 0.72 billion	SL	648	16y	L+40bp	L+55-110bp	PF
(2005)	3.6 mtpa	L/C Facility	40	15y6m	L+40bp	L+55-110bp	
		Equity	32				
(signed Jan 2005)	USD 200						
Qatar Qatargas II	USD 9.68 billion	SL	3 600	15y	L+50bp	L+95-125bp	PF
(2007)	15.6 mtpa	Islamic loan	530	15y	na	na	PF
(signed Aug 2005)	USD 621	USEXIM[G]*6	405	16y	na	na	PF
		SACE[G]	400	12y	na	na	PF
		Sponsors loan	1 944				
		Equity	2 800				

Table C.1 Investment and finance for recent LNG projects (continued)

Project (Operation start) (Finance status)	Investment amount production capacity unit Cost*2	Finance	Amount USD million	Maturity year month	Pre- completion interest	Post-completion interest	Type*3
Qatar Qatargas III	USD 5.77 billion	SL	1 488	16y	na	na	PF
(2009)	7.8 mtpa	USEXIM[G]	340	16y	na	na	PF
(signed Apr 2006)	USD 740	JBIC[G]	1 000	16y	na	na	PF
		SL	1 212	16y	na	na	SG
		Equity	1 730				
Qatar Qatargas IV	II + III =	SL	2 800	15y6m	L+30bp	L+50-60bp	PF
	USD 5.71 billion						
(2010)	7.8 mtpa	L/C Facility	225	15y6m	L+30bp	L+25-30bp	
(closed Jul 2007)	USD 732	Sponsors loan	1 200				
		Equity	1 489				
Qatar RasGas II	II + III =	SL	970	15y		L+45-65bp	PF
	USD 10.3 billion						
(2004)	14.1 mtpa	Bond	1400	15y2m		coupon 5.289%	PF
II+III (Phase 1 Aug2005)	USD 347	Bond	850	22y2m		coupon 5.838%	PF
		Sponsors loan	1380	22y			
		Equity	3500				
Qatar RasGas III	USD 10.3 billion	Bond	800	21y		coupon 6.332%	PF
(2008)	15.6 mtpa	Bond	750	10y		coupon 5.832%	PF
(Phase 2 Sep 2006)	USD 347	Sponsors loan	664			L+148	
Yemen LNG	USD 3.7 billion	SL	650	11y9m	L+165bp	L+165-210bp	PF
		COFACE/KEXIM /NEXI[G]	672	15y9m	na	na	PF
		KEXIM	240	15y9m	na	na	PF
		JBIC	120	15y9m	na	na	PF
		Credit Facility	1 102				SG
		Equity	1 216				
(2009)	6.7 mtpa						
(signed May 2008)	USD 552						
Algeria Skikda	USD 2.8 billion						
(2011)	4.5 mtpa						

Table C.1 Investment and finance for recent LNG projects (continued)

Project (Operation start) (Finance status)	Investment amount production capacity unit Cost*2	Finance	Amount USD million	Maturity year month	Pre- completion interest	Post-completion interest	Type*3
Egypt ELNG (T1)	USD 1.32 billion	A Loan	4 47.7	15y	L+85bp	L+150-235bp	PF
(2005)	3.6 mtpa	B Loan(EIB[G])	1 89.2	12y	L+85bp	L+140-190bp	PF
(signed Jun 2004)	USD 367	C Loan(EIB [G])	1 89.2	15y	L+85bp	L+120-195bp	PF
		SL	154	12y	L+190bp	L+250bp	PF
		Equity	335				
Egypt ELNG (T2)	USD 0.96 billion	SL	411	11y6m	L+60bp	L+110-150bp	PF
(2005)	3.6 mtpa	SL(EIB[G])	144	10y		L+60-120bp	PF
(signed Jul 2005)	USD 267	SL	144	12y		L+60-120bp	PF
		Credit Facility	180				PF
		Equity	221				
Egypt SEGAS (T1)	USD 12 billion	SL	970				PF
(2005)	5 mtpa	EIB					PF
(closed Aug 2007)	USD 240						
Nigeria NLNG (T4,T5)	USD 1.97 billion	SL	180	6y3m	L+250bp	L+250bp	PF
(2006)	8.2 mtpa	ECGD[G]	215	8y3m	L+30bp	L+30bp	PF
(signed Dec 2002)	USD 240	SACE[G]	190	8y3m	L+40bp	L+40bp	PF
		USEXIM[G]	115	8y3m	L+40bp	L+40bp	PF
		NCM[G]	100	8y3m	L+65bp	L+65bp	PF
		SL	160	7y3m	L+290bp	L+290bp	PF
		AfDB	40	8y3m	L+250bp	L+250bp	
Nigeria NLNG (T6)	USD 1.2 billion						
(2008)	4.1 mtpa						
	USD 293						
Equatorial Guinea	USD 1.4 billion	all Equity	1 400				
EGLNG							
(2007)	3.4 mtpa						
	USD 412						
Angola LNG	USD 4 billion						
(2012)	5.2 mtpa						
	USD 769						
Trinidad and Tobago	USD 1.3 billion	Equity/Sponsor	1 300				
Atlantic (T4)		Loan					
(2005)	5.2 mtpa						
	USD 250						

Table C.1 Investment and finance for recent LNG projects (continued)

Project (Operation start) (Finance status)	Investment amount production capacity unit Cost*2	Finance	Amount USD million	Maturity year month	Pre- completion interest	Post-completion interest	Type*3
Peru LNG	USD 3.8 billion	IDB	1 050				
(2010)	4.4 mtpa	USEXIM/KEXIM/ SACE	950				
(in finance)	USD 864	IFC	300				
		Bond	350				
		Equity	1 550				
Norway Snøvit	NOK 58.3 billion						
(2007)	4.2 mtpa						
Russia Sakhalin II	USD 19.4 billion	SL	1600				PF
(2008)	9.6 mtpa	JBIC	3700				PF
	USD 2021	Equity					

Source: Company information, media reports
Notes: *1 Projects under operation after 2000, under construction or planning with “final investment decision”
*2 Unit Cost=Investment Amount/Production Capacity
*3 Types of Finance;
PF: Project Finance (limited recourse finance)
SG: Finance with Sponsors Guarantee (recourse to sponsors)
*4 SL: Syndicated Loan
*5 L: Libor (London Inter Bank Offer Rate)
*6 [G]: Guarantee Facility
Acronyms: ADB: Asian Development Bank
AfDB: African Development Bank
ECGD: Export Credits Guarantee Department
EIB: European Investment Bank
IDB: Inter-American Development Bank
IFC: International Finance Corporation
JBIC: Japan Bank for International Cooperation
KEXIM: The Export Import bank of Korea
NCM: Gerling NCM Credit and Finance AG
NEXI: Nippon Export and Investment Insurance
USEXIM: Export Import Bank of the United States

Table C.2 Country risk classifications of LNG supplying countries

Classification	1999	2008
0	■ Australia Norway ■ United States	■ Australia ■ Norway ■ United States
1		
2	■ Brunei ■ United Arab Emirates (UAE)	■ Brunei ■ Malaysia ■ Oman ■ Qatar ■ Trinidad Tobago ■ United Arab Emirates (UAE)
3	■ Malaysia □ Oman ■ Trinidad Tobago	■ Algeria □ Russia
4	Egypt ■ Qatar	■ Egypt □ Peru
5	Papua New Guinea Peru Venezuela	■ Indonesia Papua New Guinea
6	■ Algeria ■ Indonesia Iran	□ Angola Iran ■ Libya ■ Nigeria Venezuela
7	Angola Equatorial Guinea ■ Libya ■ Nigeria Russia Yemen	■ Equatorial Guinea □ Yemen

■ = Operating □ = Under Construction
Others; planning or proposing LNG exports
*The Country Risk Classifications produced for the purpose of setting minimum premium rates for transactions covered by the Arrangement on Export Credits by the OECD.

ANNEX D: ABBREVIATIONS

ASEAN	Association of South-East Asian Nations
bbl	Barrel
BBL	Balgzand-Bacton Line
bcf	Billion cubic feet
bcm	Billion cubic metres
b/d	Barrels per day
BERR	Department for Business, Enterprise and Regulatory Reform, the United Kingdom
boe	Barrels of oil equivalent
Btu	British thermal unit, 1 Btu = 1 055 joule, 0.0002931 kWh
CBM	Coalbed methane
CCGT	Combined-cycle gas turbine
CFE	La Comisión Federal de Electricidad = Mexico's national electric power company
CHP	Combined production of heat and power
CIF	Cost, insurance and freight: a term of sales where the selling price includes cost of goods, insurance and freight
CIS	Commonwealth of Independent States, alliance of former USSR republics
CNG	Compressed natural gas
CNOOC	Chinese National Offshore Oil Corporation
CNPC	Chinese National Petroleum Corporation
CRE	La Commission de régulation de l'énergie = national energy regulatory authority of France La Comisión Reguladora de Energía = national energy regulatory authority of Mexico
CSM	Coal seam methane = CBM
DES	Delivered ex-ship: a term of sales where transfer of risk does not occur until the ship has arrived at the port of destination and goods made available for unloading to the buyer. Sellers take responsibility of shipping. The price is essential the same as CIF, indicating the price at the unloading port.
ECA	Export credit agency
EIA	Energy Information Administration, the United States
E&P	Exploration and production
EPC	Engineering, procurement and construction
ERGEG	The European Regulators' Group for electricity and gas, set up by the European Commission
EU	European Union
EUR	Euro
FEED	Front-end engineering and design
FERC	Federal Energy Regulatory Commission, the United States
FID	Final investment decision
FOB	Free-on-board: a term of sales where the selling price that does not include shipping, indicating the one at the loading port. Buyers arrange shipping transportation.
FSRU	Floating storage and regasification unit
FSU	Former Soviet Union
GBP	Pounds (Currency of the United Kingdom)
GECF	The Gas Exporting Countries Forum
GHG	Greenhouse gas
GIIGNL	The International Group of Liquefied Natural Gas Importers
GTL	Gas-To-Liquids
GW	Gigawatt (10^9 watts)

GWh	Gigawatt hour
HDD	Heating degree-days
HOA	Heads of Agreement
IEA	International Energy Agency
IOC	International oil company or Indian Oil Corporation
IOGC	International oil and gas 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 metres
MENA	Middle East and North Africa
MJ	Megajoule
MOU	Memorandum of Understanding
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
NGL	Natural gas liquid
NIMBY	Not in my back yard
NIOC	National Iranian Oil Company
NNPC	Nigerian National Oil Company
NOC	National oil company. Or Libya's 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
ORV	Open-rack vaporiser (regasification equipment)
PSA (PSC)	Production sharing agreement (contract)
SCV	Submerged-combustion vaporiser ((regasification equipment)
SRU	Shuttle and regasification unit (onboard regasification vessel)
SPA (SPC)	Sale and purchase agreement (contract)
Tcf	Trillion cubic feet
Tcm	Trillion cubic metres
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 E: 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 expected to be processed in a year.
Base-load power	Power supplied by generation units that run continuously.
Basis differential	The difference between spot cash prices at different locations at the same time.
Brownfield project	Expansion project to an existing plant, or renewal project at existing plant
City gate	The point at which a local distribution company (LDC) receives gas from a pipeline or transmission system.
Combined Cycle Gas Turbine (CCGT)	A system to generate electric power through a combination of steam and gas turbines. It burns fuel gas in compressed air and runs gas turbines with the resulting high-temperature combustion. The very high temperature exhaust gas from the gas turbines is suitable for input into a heat-recovery boiler, which in turn provides steam to the steam turbines. A gas turbine can reach its full running capacity in ten minutes from ignition, whereas a simple steam turbine needs more time to reach required temperature from steam. By combining the two, the CCGT system can start operations quicker than a steam-turbine power generation plant.
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 raw material 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 assumed 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, i.e. 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)	The maximum capacity of power generation, storage withdrawal, capacity 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 the indicator are slowed outside of a certain indicator range so that both buyers and sellers are partially protected from moves of the indicator outside a certain range.
Sour gas	Natural gas that contains significant amount of hydrogen sulphide.
Take-or-pay	A clause in a gas (or an LNG) supply contract that dictates the seller shall receive payments from a buyer for a minimum quantity of gas (or LNG), irrespective of whether the buyer takes delivery.

ANNEX F: CONVERSION FACTORS

Table F.1 Conversion factors for natural gas price

From: / To: (multiply by:)	USD /MBtu	USD /1 000 m³	USD / tonne	USD / MWh	USD / TJ
USD /MBtu	1	37.912	51.56032	3.412	0.0009478
USD /1 000 m³	0.02638	1	1.3600	0.09000	0.00002500
USD / tonne	0.01939	0.7350	1	0.06615	0.00001838
USD / MWh	0.2931	11.11	15.11	1	0.0002778
USD / TJ	1 055	40 000	54 400	3 600	1

Note: Based on gas with 40 MJ/m³

Table F.2 Conversion factors for natural gas volumes

From: / To: (multiply by:)	bcm per year	million tonnes per year	bcf/d	Tcf per year	PJ per year	TWh per year	MBtu per year	Mtoe per year
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/m³

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