LNG Today:

the promise and the pitfalls

Andy Flower & Richard King

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By Andy Flower
and Richard King

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Gas Strategies

Gas Strategies was formed in 1989 as the energy consulting arm of its parent company, EconoMatters Ltd. The company advises both commercial and governmental clients on the international gas and LNG businesses and offers a number of related products and services. Its team of experts bring a broad range of skills and experience that support our core activities which include; due diligence and project audit, analysis and modelling of gas markets and prices and guidance on competition, liberalisation, restructuring and regulation. The company offers specialist expertise in a number of areas, which include LNG, commercial gas contracts and negotiation and gas and power project economics. More details of Gas Strategies services can be found at **www.gas-strategies.com**.

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Foreword: LNG mystique, history and phenomenal growth

by James Ball, Chief Executive, Gas Strategies

Since its modest and – many at the time thought, incredible – beginnings in 1964, the international LNG business has grown to be a prominent part of the world natural gas business. To many, it is the sexiest, most challenging and most international area of natural gas. Yet, it remains one of the most mysterious. Its projects have continued to break records as the largest-ever capital project in nation after nation and set records in worldwide project financing. Yet it accounts for less than 6% of world gas consumption. Its technology is not really very complicated, but its commercial structures are difficult to assemble. It is an industry of paradoxes.

Two major companies that were in at the pioneering stages of LNG, but left it decades ago, have recently re-entered through mergers (Exxon joining with Mobil, Conoco with Phillips), and others have re-joined the fold. They see an industry whose share of world gas consumption, while modest in global terms, has doubled in the last 10 years and whose growth rates are staggering. The number of LNG ships in operation today is almost double the number in 1990, and a record number of ships are due to be delivered over the next five years, more than tripling the carrying capacity of the fleet in only 15 years.

After faltering in the early 1980s in the Atlantic basin where it all began, LNG became a major force in Asia, the region that continues to dominate its markets. At the turn of the century, the focus of activity has swung back to the Atlantic and in the last five years LNG imports there have grown 75% compared with 30% in Asia, although in absolute terms, Asia's 27 mtpa rise beat the Atlantic's 13 mtpa over this period. Likewise, production has shifted: counting only projects under construction and existing plants, the Middle East, now selling to both Asia and Europe, provided just 7% of world LNG in 1995; by 2005 it will be 20%. Atlantic basin suppliers will be 35% by then versus Asian suppliers with 45%; in 1995 Asian producers accounted for double the Atlantic basin supply. New supplies and markets will change the balance again.

LNG is a business undergoing phenomenal growth and huge changes in national and corporate composition, and plenty of outsiders want in. Lots of people want to know more. They could find or derive all the above facts from this book, but its purpose is not simply to assemble facts and figures.

LNG Today: the promise and the pitfalls aims to enable you to demystify the world of LNG while removing none of the mystique; to explain what is not complicated and what still is; and to show how the markets have behaved and how they might evolve in the future. It shows the firmly established producers and where the new ones are likely to emerge. And, it addresses the perennial yet unresolved LNG question: will a truly spot market and commodity model emerge in this business long held to tight structures by its chains?

Still, this remains a basic introduction. That is a useful reminder for the initiated and first stop for the uninitiated: a voyage through the status of the technology, from liquefaction through shipping to terminalling and regasification; a summary of the commercial structures of LNG supply chains; and a round up of key supply/demand analysis.

It was designed to complement the Alphatania course, *LNG: The Commercial Imperatives*, yet also stands on its own as a basic LNG text on the modern LNG industry (in which, as always, history remains important).

I should also say something about what went into this book: the researcher Richard King searched his databases, scoured an array of outside sources, and laid out a basic text. He then subjected his raw text to a thorough re-write by co-author Andy Flower, someone with not only 22 years of first-hand experience in LNG, but also someone who has had to analyse and explain it to corporate management and conference audiences alike, doing so on numerous occasions over a long enough period to have seen fashions come and go and markets ebb and wane. And, not satisfied with this, the two then subjected their own joint work to scrutiny by a host of other LNG experts from Gas Strategies, who added their own stories, comments and insights, challenging a few of the conclusions in the draft along the way. That the final work is as fluid and consistent is a tribute to the authors, that it is as far-reaching is a tribute to their method of creatively using a wider collaborative circle. That it is published and promoted is the work of publishers, the Energy Publishing Network.

And, by the time you read it, the industry will have moved on enough to maintain the mystique and stayed enough the same to make this volume useful.

Executive summary

Chapter 1: An introduction to LNG

LNG (Liquefied Natural Gas) is gas cooled to below –161°C, where it liquefies and can be stored as a boiling liquid in insulated tanks. LNG carried by specially built ships offers an alternative means of transportation to pipelines, and may be more economic than pipelines particularly over long distances. Around 6% of world gas production is transported as LNG.

The LNG industry developed from experiments in the USA in 1950s, with the first delivery of LNG to the UK in 1959 and commercial deliveries of LNG from Algeria to the UK and France in 1964 and 1965. The industry then saw major growth with new markets in Japan from 1969, supplied from Alaska and Brunei, and later Indonesia, Malaysia and Australia. The oil price shock in 1973 encouraged the further development of LNG as it improved the competitive position of LNG and led to the development of oil price indexation in LNG supply contracts.

First deliveries of Algerian LNG to the USA occurred in 1972, but despite the construction of four US receiving terminals, LNG sales to the US collapsed and remained at a low level through the 1980s and 1990s, returning to their 1979 peak in 2000. During the 1980s and early 1990s further LNG markets developed in Europe and in Korea and Taiwan. The late 1990s and early 2000s have seen rapid growth with expanding LNG markets in the US, Spain, Portugal and Greece and new production facilities in Oman, Qatar, Nigeria and Trinidad.

World LNG trade was approximately 105 mtpa in 2001 with major LNG markets in the Asia-Pacific region, particularly in Japan, and rapidly growing markets in the Atlantic basin. With capacity expansions planned at many production and reception facilities and the first European export project planned, the Snøhvit project near Hammerfest in the Norwegian Barents Sea, LNG is likely to increase in global reach and significance.

Chapter 2: The LNG chain

Each LNG project consists of a continuous chain of activities linking the gas production to the gas user. Links in the LNG supply chain include upstream (gas production), liquefaction, shipping, regasification, and distribution (as natural gas) to end-users.

Upstream covers the exploration, development and production of gas. LNG projects typically require large gas reserves (in excess of 10 Tcf or 280 Bcm), able to produce gas at a plateau level for at least 20 years. The quality of the gas is also a key factor in determining whether LNG projects are economic.

Liquefaction involves the processing and cooling of gas to –161°C. Liquefaction units are referred to as LNG trains, with most LNG plants operating between 2 and

8 independent trains. There are two main processes for liquefying natural gas, the Multi-Component Refrigerant process and the Phillips Cascade process. These are both described. Liquefaction plant capital costs may make up over 80% of total liquefaction costs, however, in recent years these have been significantly reduced through improved technology and economies of scale.

Shipping forms the vital transportation link in the LNG chain. LNG is carried at atmospheric pressure in specially built LNG tankers. Most of the 128 LNG ships in operation today have a capacity of 125,000 m^3 to 140,000 m^3, although there are a number of smaller ships still in operation. All but one of the 50+ ships on order are in the 135,000 m^3 to 145,000 m^3 range. Most LNG ships use either the Kvaerner Moss design or one of two Membrane designs. New LNG ship prices in 2001 were around $170m.

LNG is unloaded from ships to LNG receiving terminals. These terminals store and regasify LNG for distribution to end-users. Typically 2 to 3% of gas is used or lost in the regasification process. Capital costs for terminals vary significantly between $200m and $1bn depending on location costs and storage capacity required.

Chapter 3: Project structures

Definition of commercial structure is a key part of LNG project development. LNG project structures must meet a range of objectives including, ensuring stability of operation, sharing risks and rewards equitably, satisfying the requirements of the host government, and minimising the potential for conflict and delay. Project structures can be grouped into three generic models: integrated projects, transfer pricing arrangements, and throughput arrangements.

In an integrated project there is common ownership of the gas reserves, liquefaction plant, and in most cases the LNG ships. An integrated project has the advantages of aligning the partner interests and avoiding negotiation of transfer prices. There is a case study of the RasGas trains 1 and 2 integrated project.

An integrated structure may not be possible in many situations because the owners of the gas reserves differ from the liquefaction plant owners. In these cases the most common alternative is a transfer pricing arrangement. The partners in each stage agree a transfer price for sale of the gas or LNG into the next stage of the process. Transfer pricing arrangements may lead to conflict, particularly when changing market conditions shift the risk/reward balance between different partners. There is a case study of the Malaysia LNG Dua transfer pricing arrangement.

The third form of project structure is a throughput arrangement where the upstream partners pay a tolling fee to use the LNG plant and then market the LNG on their own behalf. Although there are no LNG projects currently operating on this basis, there is a case study of Atlantic LNG trains 2 and 3, which will operate with a form of throughput arrangement from 2002.

Chapter 4: Sources of LNG

World LNG production capacity in early 2002 was 120 mtpa, with total capacity expected to increase to over 160 mtpa by 2005 or 2006 as new facilities are commissioned. There are three major LNG producing regions: Asia-Pacific accounting for 50% of production in 2001, the Atlantic basin 28%, and the Middle East 22%.

The Atlantic basin covers LNG production facilities on both sides of the Atlantic as well as North African LNG facilities on the Mediterranean. The largest Atlantic basin LNG supplier is Sonatrach in Algeria, but in 1999 new LNG projects were commissioned in Trinidad (Atlantic LNG) and Nigeria (Nigeria LNG). Trinidad and Nigeria's LNG production capacity is being rapidly expanded with several new trains under construction. In addition an LNG plant is under construction at Damietta in Egypt. There are also proposals for further expansions or new facilities in Norway, Trinidad, Egypt, Nigeria, Angola, Venezuela and Namibia.

Middle Eastern LNG production began with the Das Island plant in Abu Dhabi in 1977. New capacity in Qatar and Oman developed between 1996 and 2000 and capacity expansions at Das Island significantly increased LNG production in the Middle East. A third train under construction at RasGas and debottlenecking work at Qatargas will increase capacity further. There are also a number of proposals for further capacity in Qatar, Oman, Yemen and Iran, however, it is unclear if sufficient buyers can be found to justify these investments.

Asia-Pacific is the largest LNG producing (and consuming) region. Around 45% of world LNG production is concentrated on the island of Borneo where there are four LNG plants (Malaysia Satu and Dua, Brunei LNG, and Bontang in Indonesia). The other Asia-Pacific producers are the Australian North West Shelf project and the Kenai plant in Alaska. The Malaysia Tiga and North West Shelf Train 4 facilities are due to come onstream in 2003 and 2004 respectively. Asia-Pacific further proposed capacity includes a number of developments in Australia, capacity expansions and new facilities in Indonesia and Brunei, and new developments in Russia (Sakhalin) and the Alaskan North Slope.

Although most potential LNG developments are within the existing supply envelopes, there is the possibility that a new supply and consumption region may develop with LNG production on the Pacific coast of South America selling to new receiving terminals in Mexico or California. The major gas sources would be Peru and Bolivia.

The table below summarises world LNG production capacity, highlighting the large increases in capacity either under construction or proposed, particularly in the Atlantic basin.

World LNG production capacity, April 2002				
Region	*Capacity in operation (mtpa)*	*Capacity under construction (mtpa)*	*Capacity proposed (mtpa)*	*Total potential capacity (mtpa)*
Atlantic basin	33.8	22.5	64.9	121.2
Middle East	26.4	6.2	35.1	67.7
Asia-Pacific	60.9	11.0	59.8	131.7
Pacific South America	0	0	11.0	11.0
Total	121.1	39.7	170.8	331.6

Source: Gas Strategies

Chapter 5: LNG markets

World LNG demand reached 105 mt in 2001. Of this total 71% was concentrated in the Asia-Pacific region and 29% in the Atlantic basin. In the Atlantic basin the main markets are in Europe, particularly France and Spain, with European markets consuming a total of 23.3 mt in 2000. Although the USA is the world's largest gas market, LNG forms a comparatively low proportion of gas supply at 4.8 mt in 2001 (1% of the US market). US LNG imports have increased significantly over recent years, however, from the level of 0.5 mt in 1996. These increases are due to surplus LNG cargoes from the Asia-Pacific market, high US gas prices in 2000 and 2001, and the commissioning of the Atlantic LNG facility in Trinidad, which is much closer to the US East Coast than other LNG plants.

Asia-Pacific is the largest LNG market, with Japan alone importing over 50% of world production. Around 70% of LNG demand in Japan is from power companies, with gas distributors also purchasing LNG. Korea and Taiwan are the other Asia-Pacific LNG importers.

In terms of market outlook, Europe is expected to be a significant growth market, with three new receiving terminals currently under construction in Spain, Turkey and Portugal, and further terminals under consideration in Spain (two), Italy (two), France (two), and the UK. Over 20 plans for new LNG import facilities in North America were suggested during the gas price peak in the US in 2001. Many of these plans have now been dropped following the decline in US prices, however, in the medium-term an increasing US supply gap is likely to lead to further LNG imports. An LNG terminal was completed in Puerto Rico in 2000 and another is under construction in the Dominican Republic. There are also proposals for terminals in Mexico, Brazil and Honduras.

Demand growth is likely to be slow in the existing Asia-Pacific markets of Japan, Korea and Taiwan due to regulatory and market uncertainty. There are significant growth prospects in the huge potential markets of China and India. A terminal is currently under development at Shenzen in China. The Dabhol terminal in India is now nearly completed, however, it is currently up for sale, following the collapse of its major backer, Enron. There are a number of other plans for terminals in India, although the future for some of them is uncertain. There is also a proposal for an LNG terminal in the Philippines.

Chapter 6: Marketing

The common contract form for the LNG business is the LNG Sales and Purchasing Agreement (SPA). SPAs were originally based on pipeline gas sales contracts, but have been adjusted to meet the specific needs of the LNG industry. LNG buyers and sellers may go through a series of agreements preliminary to signing an SPA, with a greater level of commitment at each stage. Typical preliminary stages include: Letter of Indication or Letter of Interest (LOI), Memorandum of Understanding (MOU), Letter of Intent (LOI), Heads of Agreement (HOA), and Confirmation of Intent (COI).

Key contractual terms in a typical LNG SPA include: term of supply (normally at least 20 years), Annual Contract Quantity (including a minimum take-or-pay obligation and conditions for flexibility in offtake and make up provisions), price, responsibility for marine transportation (either FOB or CIF/ex-ship), scheduling procedures, heating value and main components of the LNG, measurement and testing, force majeure, and destination flexibility (or the lack of it).

There are different pricing systems in place in the three major market regions of Asia-Pacific, Europe and the USA. In the Asia-Pacific LNG prices are typically indexed to crude oil prices, either in Japan or Indonesia, in some cases with an ‘S’ curve to limit the impact of extreme oil price movements. In Europe LNG is competing with pipeline gas and adopts similar formulae which are typically indexed to crude oil or oil products (gasoil and fuel oil), although there may also be elements of coal, electricity or inflation indexation. In the USA gas prices are set by gas to gas competition, driven by supply and demand. LNG delivered prices to the US market are typically based on Henry Hub gas prices plus or minus a locational differential reflecting the basis between the LNG delivery point and the Henry Hub.

Chapter 7: Shipping

There are currently around 130 LNG ships in operation, with over 50 more planned or under construction. Most existing ships have a capacity of 120,000 m^3 to 140,000 m^3, although there are a number of smaller ships delivering gas to medium-sized gas distributors in Japan and to terminals in Spain, France and Italy that cannot receive large ships. The lifespan of an LNG ship has been extended from the design expectations of twenty years and there are now a number of ships of over twenty or even thirty years' operation. Total LNG fleet capacity has increased steadily from the first ships in service in 1962, reaching over 14 mcm by 2001.

Prices of LNG ships have varied considerably over the last two decades, however in recent years prices have fallen and current price for a standard 135,000 m^3 to 140,000 m^3 LNG ship is around $170m. Although LNG ships have been built in shipyards in Japan, Korea, France, Finland, Spain and Italy, the market is currently dominated by Korean and Japanese shipyards. In early 2002 there was a record 58 ships on order for delivery between 2002 and 2006, all but of one of these ships is in the 135,000 m^3 to 145,000 m^3 category. Unusually around 40% of ships on order do not appear to be linked to a particular LNG project and may be developed for speculative reasons.

LNG shipping costs are very much a function of the distance between the liquefaction plant and the receiving terminal. Shipping costs include fixed costs (capital charges, crew costs and insurance) and variable voyage costs (fuel, boil-off gas and port charges), with fixed costs generally accounting for two-thirds of total transportation costs. An illustration of typical costs per MMBtu for various distances is provided.

Chapter 8: Short-term trading

Although long-term contracts have traditionally underpinned the LNG market, there has been a low level of short-term or spot LNG trading throughout its history. In recent years the level of short-term trading has increased, reaching nearly 6% of total LNG production in 2000. Short-term trading began as sellers sought to utilise spare liquefaction capacity and some buyers found that gas demand increased more quickly than forecast. In the 1980s almost all short-term trading was between suppliers and buyers that already had a long-term contractual relationship. In the early 1990s this changed somewhat as shut-downs of Algerian production forced European buyers to seek LNG cargoes from the Middle East and Australia. From 1996 the US market also began to buy spot LNG cargoes as Asia-Pacific sellers aimed to offload excess LNG following the downturn in demand in Japan, Korea and Taiwan.

Short-term LNG trades may follow a variety of pricing structures, including indexation to crude oil or oil product prices, or netback from pipeline gas prices. In the Atlantic basin the proximity between the US and European markets provides sellers and buyers with an opportunity to arbitrage prices and divert LNG cargoes to attract the highest price. Analysis of deliveries from the Atlantic LNG plant in Trinidad shows that when prices in the US are above European prices deliveries will be diverted to the US from Spain, whereas the situation reverses when European prices are above US prices.

The main factors needed for the expansion of short-term trading are surplus LNG supply, market demand and receiving capacity, uncommitted ships, and flexible contracts. At the current time the main constraints on the further development of short-term trading are the shortage of uncommitted ships and the lack of flexibility in existing contracts. This seems likely to change in the near future as a number of uncommitted ships come online and buyers push for greater flexibility in supply contracts. Given these factors, the short-term LNG market is expected to expand somewhat in the medium-term, however, the large investments and commitments required for the construction of LNG plants, ships and terminals, is likely to prevent the short-term market replacing the current framework of long-term contracts.

Chapter 9: The outlook for LNG

LNG trade has grown significantly in recent years and there are now predictions of annual trade doubling by 2010 and tripling by 2015. Although these forecasts may be over-optimistic, further acceleration in the pace of change will be needed. Expected gas supply gaps in the USA and Europe, and reducing LNG costs, make LNG an increasingly attractive prospect for these growing markets. The opportunities for sellers to arbitrage prices between the US and European markets also increases the attractiveness of trading in the Atlantic basin. During 1996 to 2001 Atlantic basin LNG demand grew by an average of 12%/year. Growth in the Asia-Pacific region has been slower, at 5%/year over the same period, and prospects for growth in the existing markets are uncertain, however, India and China hold out the possibility of large new markets for LNG.

There are currently a very large number of liquefaction capacity expansions or green-field projects proposed, both in existing regions and new areas such as Russia, Norway, Iran, Venezuela, and south-west Africa. This is likely to lead to fierce competition between projects with only those able to secure markets proceeding to completion. The key issue for new projects will be cost, with those projects in the Atlantic basin having a significant advantage due to their proximity to growing markets.

The emergence of a buyers' market and increased short-term trading is changing the structure of the LNG market, including increased flexibility in contracts, and increasing volumes of uncommitted liquefaction and transportation capacity. Sellers are learning to deal with new types of buyers, as new players such as IPPs and new entrant suppliers seek to secure gas supplies in liberalising gas markets. The development of short-term LNG trading will continue, however, the market is likely to remain largely dependent on long-term contracts in the medium to long-term.

The future is likely to owe much to three emergent trends.

- Changes in downstream markets and the emergence of new markets that are forcing buyers to seek much more flexible supplies than in the past.
- Reductions in the costs of LNG to the point where it is already competitive with pipeline gas in a number of growing markets.
- The development of short-term LNG trading and the flexibility this gives for LNG players to improve returns on investment and exploit and further develop niche market opportunities.

Chapter 1: An introduction to LNG

LNG is a vital part of the gas industry, as well as the one of the industry's fastest growing sectors. This chapter provides an introduction to the nature and characteristics of LNG, and traces the development of the LNG industry since its beginnings in the 1950s.

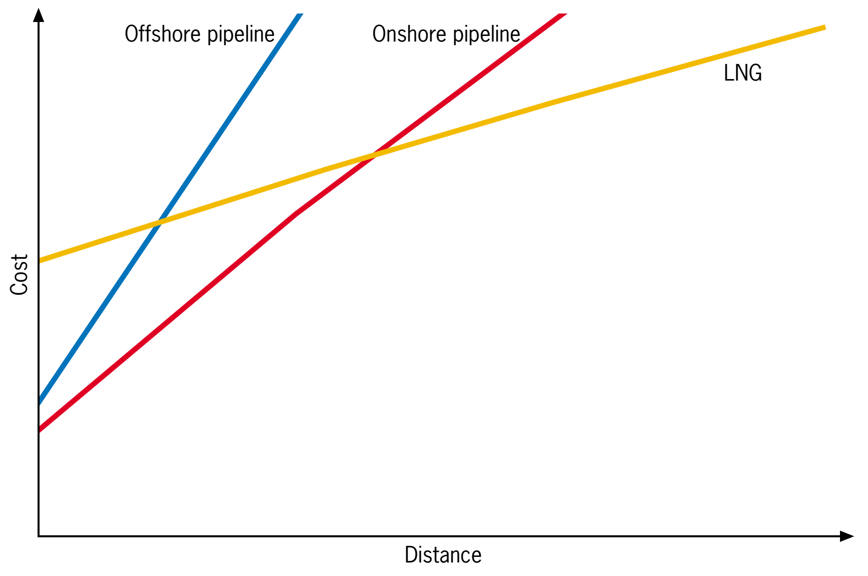
What is LNG?

LNG (Liquefied Natural Gas) is natural gas that has been cooled to below –161° centigrade, the temperature at which its main constituent, methane, liquefies (and boils at ambient pressure). It is stored in insulated tanks, either on land or in ships, as a boiling liquid. The LNG is maintained at its boiling temperature and produces 'boil-off gas', which gradually reduces the volume of LNG in the tanks. In its liquid state natural gas occupies about one-sixth hundredth of the volume it occupies in a gaseous state (at standard temperature and pressure). The reduction in volume through liquefaction opens up extra possibilities for gas including short and long-term storage (for instance peak-shaving storage to meet sudden demand peaks) and surface transport as a liquid by land and sea, particularly over long ocean distances in specially built LNG carriers.

Why LNG?

LNG offers an alternative to pipelines as a means of transporting natural gas to the market. Where distances are short and markets are sizeable, a pipeline will usually be the lowest cost development option. There are exceptions where politics, regulations, or topography provide obstacles to pipeline construction. Generally speaking, a combination of large scale and long distances provides the conditions needed for the international movement of gas as LNG. Figure 1 illustrates the relationship between the cost of moving natural gas by pipeline and as LNG, and the distance between the gas reserves and the market.

Figure 1: Pipeline and LNG delivered cost comparison



Source: Gas Strategies

Pipeline costs are essentially distance-related; the further the gas has to be transported the more pipe and compressor stations are needed. The cost of laying pipelines offshore is usually higher than for onshore pipelines, although offshore costs are coming down and laying a pipeline through a heavily populated area can increase onshore costs substantially.

For LNG, a major part of the investment cost is independent of distance. Facilities to liquefy the gas close to the source of production and regasify it in the consuming country are required whatever the distance over which the LNG has to be transported. Consequently, LNG costs increase more gradually with distance than pipeline costs, but the costs of liquefaction preclude LNG for most short distances. Over long distances LNG is often the most economic method of supplying natural gas, particularly where the alternative is an offshore pipeline.

LNG is therefore most commonly an option for monetising stranded gas, that is gas reserves distant from a market and not connected to existing infrastructure. Overall, pipelines remain the predominant means of delivering natural gas to the market, whereas just under 6% of the world's gas production is transported as LNG.

The development of the LNG industry

Many people in the gas industry consider LNG to be a well established, if relatively small, sector of the international gas business. It is, in fact, less than four decades old as a commercial business and owes its birth to a small number of risk-taking pioneers without whom the business might never have developed. The LNG industry, as we describe later, has grown rapidly since the start of the first commercial trade in 1964, itself the indirect outcome of a project to supply fuel to and cool a meat-canning factory in Chicago which was deemed crazy by many contemporary observers.

The first LNG developments in the US

The technology for low temperature liquefaction of gases, including methane, has existed for over a century, something which fascinated Billy Wood Prince, President of Union Stockyards of Chicago (dubbed 'the father of LNG'). Prince fashioned a project, in the 1950s, together with Continental Oil Company (Conoco), to liquefy natural gas in Louisiana and ship it by barge up the Mississippi to his meat-canning factory in Chicago where the gas would be used as fuel and the cold extracted from the LNG would replace much of the refrigeration horsepower. Constock, the company formed with Conoco, developed liquefaction and insulation technology which worked on a small commercial scale but, although a small liquefaction plant and an insulated barge were built and tested, the project was aborted because of unsatisfactory economics and concerns about the operational viability of a scheme relying on what was then cutting edge technology in a crowded waterway. Constock persevered, however, and in 1959 used a converted dry cargo vessel, the *Methane Pioneer*, to transport 2,000 tonnes of LNG across the Atlantic from Louisiana to Canvey Island in the UK in a test with co-operation from the British Gas Council.

Market development in the Atlantic and Mediterranean basins

Constock's experimental UK delivery intrigued Shell, and it bought a 40% stake in the company, (which thereupon had its name changed to Conch). This newly constituted company set about creating an LNG supply from Algeria to the UK with a 40% share in Camel, the operator of the first LNG plant at Arzew in Algeria, and designed the first purpose-built LNG carriers: two 27,500 m^3 ships, the *Methane Progress* and the *Methane Princess*. The world's first commercial delivery of LNG was made to Canvey Island in 1964, followed in 1965 with deliveries by the *Jules Verne* to Le Havre in France, Gaz de France having also taken an interest in the project. These baseload ocean-borne LNG supplies from Algeria demonstrated the operational viability of LNG. This was the operational breakthrough; respectable profitability was not to emerge for another decade or so and there have since been many examples of unsuccessful LNG investments of time and money, some of them large.

In the early 1960s, Shell also set about developing an LNG supply for the UK from Nigeria, where it had ample reserves of gas. This project was suspended when large reserves of gas were discovered in the North Sea. Various Nigerian LNG projects then went through a variety of forms and vicissitudes, eventually resulting in the first Nigerian exports some four decades later, but not to the UK.

The Mediterranean/Atlantic LNG trade was augmented in 1970 by an Esso-led project bringing LNG from Libya to Italy. This project was bedevilled by technical problems and hardware failures which resulted in project losses. Esso withdrew and stayed out of the LNG business until the 1990s when it made significant commitments to developing LNG from East Natuna (Indonesia) and, with Shell and others, from Venezuela.

Apart from Algerian exports to France and Spain, LNG in the Mediterranean/Atlantic arena was largely moribund for about twenty years. During this period a series of deals with buyers in the US were considered but most fell apart in some cases at significant costs in terms of idle investment in ships, liquefaction plant and receiving terminals.

The development of the Asia-Pacific market

Fortunately for the progress of the LNG industry, its faltering start in the Western hemisphere was picked up in the Far East. In the 1960s, Mr H Anzai, Managing Director of Tokyo Gas, encouraged by the operational success of the Algeria project, went on the market for 0.25 mtpa of LNG. Potential suppliers indicated that they could not supply that volume at the price Anzai demanded – not more than $0.77/MMBtu. Anzai managed to persuade Tokyo Electric to take 0.75 mtpa, to make a total demand of 1 mtpa. Only two bidders submitted a final offer: Phillips and Marathon in Alaska, and Conch, using gas from a new Shell discovery in Brunei. The Alaskan bid won in 1966, commencing delivery in 1969. The contract price, delivered in Tokyo Bay, for a 15-year supply contract with an optional five-year extension, was a flat $0.52/MMBtu. Although it would not be recognisable as a valid LNG price today, this was none the less approximately 60% higher than crude oil prices (around $1.80/bbl) at the time. Tokyo Electric diverted criticism of the contract price by emphasising the important anti-pollution benefits of using natural gas, rather than crude oil, in power generation. Japanese cities had heavily polluted air in in the 1960s and the anti-pollution argument was so well accepted by the public that from about 1970 onwards many new Japanese thermal power plants could only obtain planning approval if fuelled by gas from LNG. This development generated a very strong LNG market in Japan from the early 1970s to the late 1980s, without which the history of LNG in the Far East might have been rather different.

Brunei supplies to Japan were negotiated during 1968 through 1970 with first delivery in December 1972. The price for the initial volumes was again flat but this time at $0.486/MMBtu. The non-Shell shareholders in Conch had withdrawn because of the poor economics expected from the project and Shell, reluctant to carry all the investment in a project which seemed destined to have marginal economics at best, took in Mitsubishi Corporation as an equal partner in midstream and downstream.

The oil price shock and capacity expansion

In 1973 the energy market was transformed by the first oil price shock. Oil prices rose steeply and the flat pricing of gas at a fraction of oil price equivalent became politically untenable. Brunei gas prices were re-negotiated, indexed to oil (Alaska followed because of a most favoured supplier clause in its contract), and suddenly LNG investors that had put projects together to gain experience of the new business found themselves making large and unexpected profits. Everybody with the right kind of gas in the Pacific Rim wanted to join the party.

In 1977 the plant at Das Island in Abu Dhabi and the Bontang plant in Indonesia started deliveries to Japan, and in 1978 the Arun plant in Indonesia delivered its first cargo. This was followed by deliveries from Malaysia in 1983.

The 1970s and the early 1980s also saw the expansion of Algerian capacity, with the construction of a liquefaction plant at Skikda in 1971, and two new liquefaction plants at Arzew in 1978 and 1981.

During the 1970s, deliveries from Algeria to the US started, first to the terminal at Everett, near Boston, in 1972. US LNG import capacity was expanded considerably towards the end of the 1970s, with the opening of the Cove Point and Elba Island terminals in 1978, and Lake Charles in 1982. However, the US trade broke down over a price dispute, leading to the mothballing of three of the terminals, Cove Point, Lake Charles and Elba Island, and deliveries continued only sporadically when the US gas price was higher than the LNG import price. Lake Charles reopened in 1989, Elba Island in 2001, and Cove Point is scheduled to reopen in 2002.

The late 1980s saw deliveries from the North West Shelf project in Australia to Japan in 1989. It also saw new markets in Belgium, with the opening of the Zeebrugge terminal in 1986, South Korea, also in 1986, and Taiwan in 1990.

Major new projects and rapid growth

The late 1990s and early 2000s have seen a boom in the LNG trade, with the opening of two new projects in Qatar in 1996 and 1999, projects in Trinidad & Tobago and Nigeria in 1999, and Oman in 2000. Of these, Atlantic LNG in Trinidad, RasGas in Qatar, and Nigeria LNG already have additional capacity under construction. There has also been a revival in US imports, which, at 5.3 mt in 2001, were over three times the 1997 level, and almost seven times the 1996 level. This was largely due to a sharp increase in US gas prices in 2000 and early 2001, but was also affected by other factors, such as the start-up of Atlantic LNG in Trinidad, which is much closer to major US markets, and therefore able to deliver LNG to the US cheaper than any other existing supplier.

Global LNG trade

The LNG trade has developed with two separate markets, the Atlantic basin (which also includes deliveries to markets on the Mediterranean and is sometimes referred to as the Atlantic/Mediterranean basin) and Asia-Pacific, each with their own suppliers. The Atlantic basin, consisting of Europe and the US East Coast, is supplied by Algeria, Libya, Nigeria and Trinidad. The Asia-Pacific market of Japan, Korea and Taiwan is supplied by South-East Asian and Middle Eastern suppliers. Recently, the Middle Eastern suppliers have also targeted Europe, and Qatargas has concluded an eight-year sales agreement with Gas Natural of Spain.

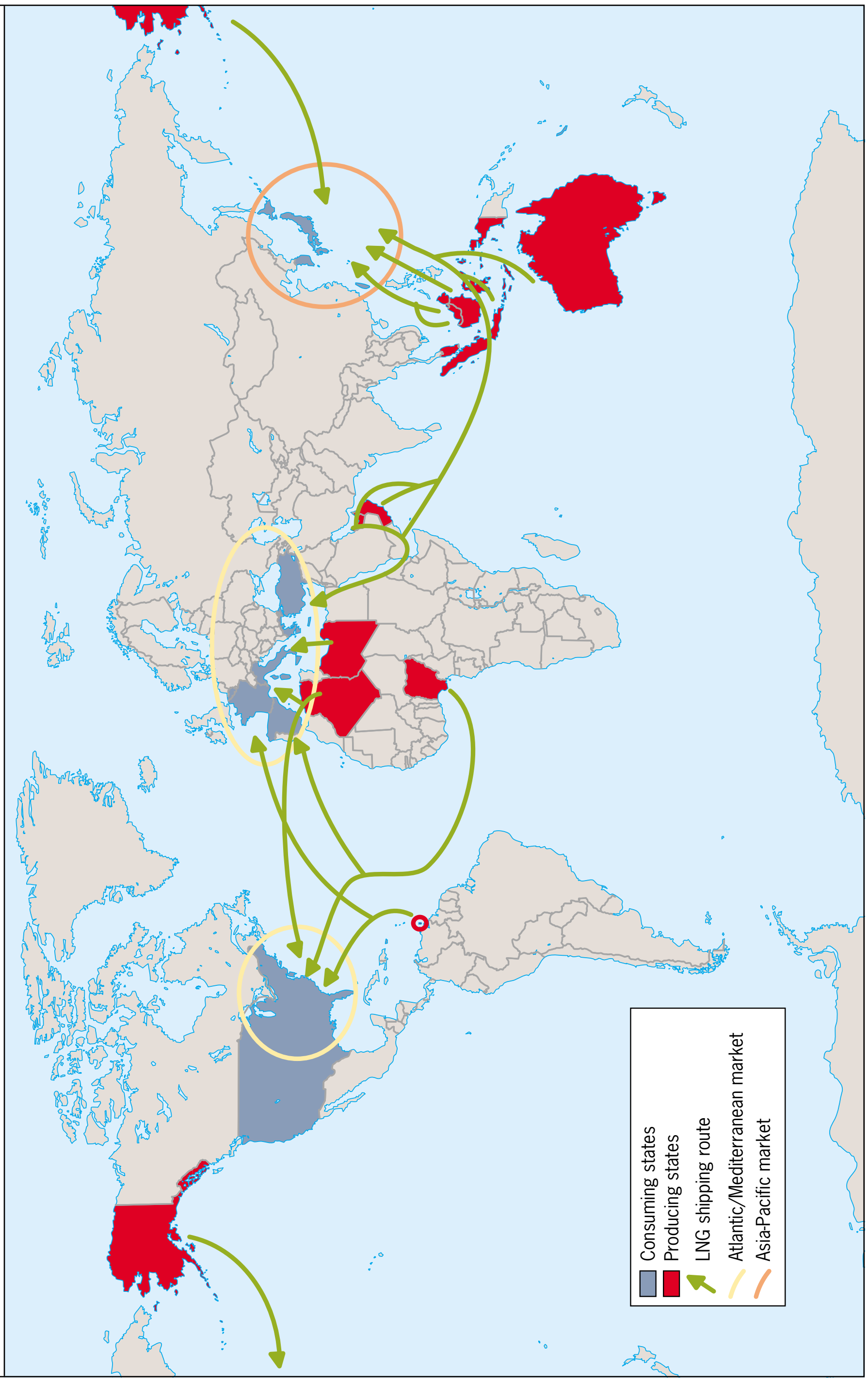
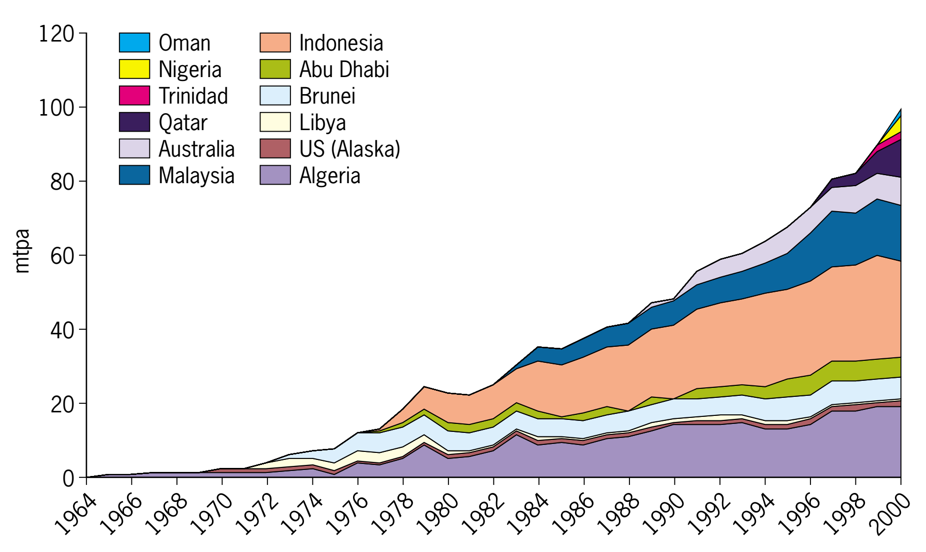


Figure 2: LNG markets and suppliers

Source: Gas Strategies

There are overlaps between the two regions but pricing has tended to be regionalised and dominated by the larger trades in the regions; in Europe and the US the majority of gas traded is supplied by pipeline, and it is against these pipeline supplies that LNG must be competitive. In Asia, however, LNG prices have followed trends set by Japanese LNG pricing, Japan being the main gas importer in the region. The large volume of LNG supplied to Japan means that Japan sets the benchmark, particularly on price, for the rest of Asia and its influence has had an impact on the newer market developments of India and may also affect China. Europe and North America share the same set of LNG suppliers and some of the suppliers trading with the Asian market have also occasionally supplied Europe and North America on a short-term trade basis.

Figure 3: World LNG exports, 1964–2000



Source: Cedigaz, BP

The global LNG trade has grown fairly steadily since its start, and has only decreased in two years, 1980 and 1981. From 1990 to 2000, it grew at an average annual rate of 5.3%, and from 1995 to 2000 at 7.5%. The Asia-Pacific market accounted for 71% of LNG demand in 2001, and the Atlantic basin market 29%. However, there are limited prospects for growth in Japan, the largest market, which currently accounts for approximately half of all LNG imports. In the last five years there has been a boom in the Atlantic basin LNG industry. Atlantic basin LNG demand grew by nearly 12% per annum between 1996 and 2001, compared with 5% per annum in the Asia-Pacific region. Demand is expected to continue to rise in the Atlantic basin, particularly the US, while in Asia-Pacific demand growth may come from new markets such as India and China. Two terminals are under construction in India and one is at an advanced state of planning in south China.

World LNG trade amounted to approximately 105 mt (144 Bcm) in 2001, and LNG was exported from 18 liquefaction plants in 12 different countries to 37 receiving terminals in 11 countries. Although LNG accounted for only about 6% of world gas consumption, it represented about 26% of gas exports. LNG is the main method of importing natural gas in Japan, Korea, and Taiwan, accounting for over 95% of their natural gas consumption, and LNG accounts for on average for 35% of the natural gas consumption of those European states that do import LNG.

Although the development of the LNG business has at times been slow, it is now enjoying a period of rapid growth, with LNG becoming an increasingly attractive prospect to monetize gas reserves and to supply growing markets. As new plants come onstream, particularly expansions in Nigeria and Trinidad, and eventually the prospect of the first European LNG production from the Snøhvit field in the Norwegian Barents Sea, LNG is likely to increase in global reach and significance.

Chapter 2: The LNG chain

Each LNG project consists of a continuous chain of activities linking the gas production to the gas user. This chapter provides an overview of the main links in the LNG supply chain, including upstream (gas production), liquefaction, shipping, and the regasification of the LNG for distribution to the end users. Each link in the chain is critically dependent on the others since a failure in one link may halt or impair the delivery of the LNG until the problem is overcome. However, as the number of liquefaction plants has grown and spare liquefaction and shipping capacity has become generally available, an interruption in a single project has become a lesser threat to supply security. This has been shown with the temporary closure of the Arun plant in Sumatra from March to August 2001; the markets were fully served by means of cargoes supplied by other sources.

Upstream

The upstream area covers the exploration, development and production of gas prior to liquefaction. Upstream may cover some processing of gas, although this also occurs as part of liquefaction. The development of LNG technology, and the reduction in liquefaction and shipping costs, has increased the options available to gas producers for bringing to market distant gas reserves. However, the gas reserves required for an LNG project have to satisfy a number of important physical and economic requirements. Firstly, the proven reserve base must be large. The delivery of 1 million tonnes of LNG per annum for 20 years is equivalent to 1 Tcf (28 Bcm) of natural gas. After taking into account the gas used and lost in the LNG chain (generally between 10% and 15%) and the reserves which have to remain in the field at the end of the project life to maintain production at the plateau level, a world-scale LNG project with a capacity of 6 to 8 mtpa, requires a minimum of around 10 Tcf (280 Bcm) of proven gas reserves.

Secondly, the reserves must be able to sustain gas production at a plateau level for the life of the project, which is usually at least 20 years. Interruptions to the gas supply would leave the liquefaction plant and the ships idle and the buyers without essential gas supplies for their customers. Consequently, planned and unplanned shutdowns of gas production must be minimised. This feature militates against the use of associated gas, where gas production rates are driven by oil production rates, unless, as for example in Brunei, non-associated gas is also available to ensure a constant flow of gas into the liquefaction plant.

A third important consideration is the quality of the gas. Associated liquids (liquefied petroleum gases (LPGs) and condensates) provide additional revenues for the project since they are separated from the gas before or during the liquefaction process and are sold separately from the LNG. All pentane and heavier hydrocarbons must be removed to avoid the development of frozen solids in the LNG. Revenues from liquids extracted from the raw gas (referred to as natural gas liquids or NGLs) can be crucial to LNG project economics. On the other hand, impurities in the gas, such as carbon dioxide, mercury or hydrogen sulphide will result in additional costs since they must be removed and disposed of before the gas can be liquefied. These costs can be significant, particularly if carbon dioxide venting is not acceptable due to environmental regulations.

Finally, the costs of delivering gas into the liquefaction plant, including production, transportation, and pre-liquefaction treatment, have to be low if the project is to be commercially viable. Credits from sales of liquids extracted from rich gas can effectively reduce the into-plant cost of gas.

Some LNG projects, such as RasGas in Qatar, are supplied by a single large field and others, such as Atlantic LNG in Trinidad and Brunei LNG, are supplied by a number of small and medium-sized fields. The gas fields may be located offshore, as in Australia North West Shelf, onshore, as in Nigeria, or both onshore and offshore, as in Bontang in Indonesia. Whatever the source of the gas supply, investors in the other parts of the chain and the buyers of the LNG will want to be sure that sufficient gas reserves are available in order to sustain LNG production throughout the planned life of the project.

Liquefaction

After some initial processing at the well-head, the gas is delivered to the liquefaction plant. It is first treated to remove any remaining water, condensates and contaminants such as carbon dioxide, mercury and hydrogen sulphide. It is then fed into a heat exchanger where it is liquefied by cooling to –161° centigrade. The liquefied gas is stored in tanks until it can be loaded onto an LNG ship for export. After the initial liquefaction no further refrigeration is normally carried out. The LNG is stored at atmospheric pressure in insulated LNG tanks at the liquefaction plant, on the ships and in the receiving terminal.

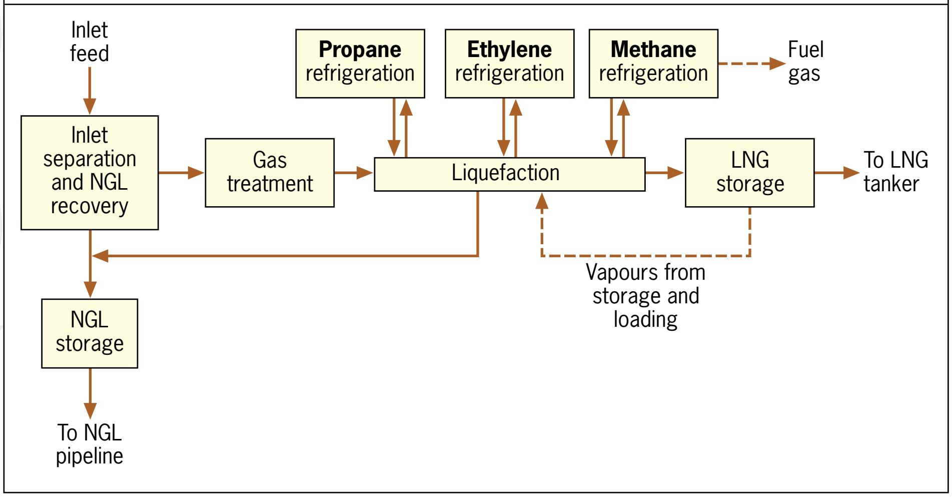
The series of processing units that treat and liquefy the gas is known as an LNG train. Nearly all LNG plants consist of two or more trains that can operate independently of each other. The largest is the Bontang facility in Indonesia which has eight trains in operation. The Trinidad LNG (Atlantic LNG) plant had a single train when it was commissioned in 1999 but is being expanded by two more trains.

The basic process used to liquefy the gas is the same as is used in a domestic refrigerator. A refrigerant gas is cooled by compression and release through a valve which lowers its temperature – the Joule-Thompson effect. The refrigerant gas is then used to cool the feedgas in a heat exchanger. There are a number of different processes that are used to apply this principle to the liquefaction of natural gas. The most widely used liquefaction technique is the Multi-Component Refrigerant (MCR) process, originally developed by Air Products and Chemicals, Inc. (APCI). An alternative is the Phillips Cascade process, first used in the Kenai plant in Alaska. An updated version, the Phillips Optimised Cascade process, is used in the Atlantic LNG plant in Trinidad. The first three trains at the Skikda plant in Algeria use the TEALARC process, developed by TEAL (a joint venture between Technip and Air Liquide), but this process is no longer available. A fourth process, developed by Black & Veatch, is currently only used in small-scale peak-shaving plants, which store gas as LNG for use at peak times. The two most common processes, developed by Phillips and APCI respectively, are examined below.

Phillips Optimised Cascade

In the Phillips cascade process the gas is cooled in three stages. The first stage uses a propane refrigerant to reduce the temperature to –35° centigrade. Then an ethylene refrigerant cools the gas to –105° centigrade before a final stage, using a methane refrigerant, reduces its temperature to –161° centigrade.

Figure 4: Phillips Optimised Cascade LNG process

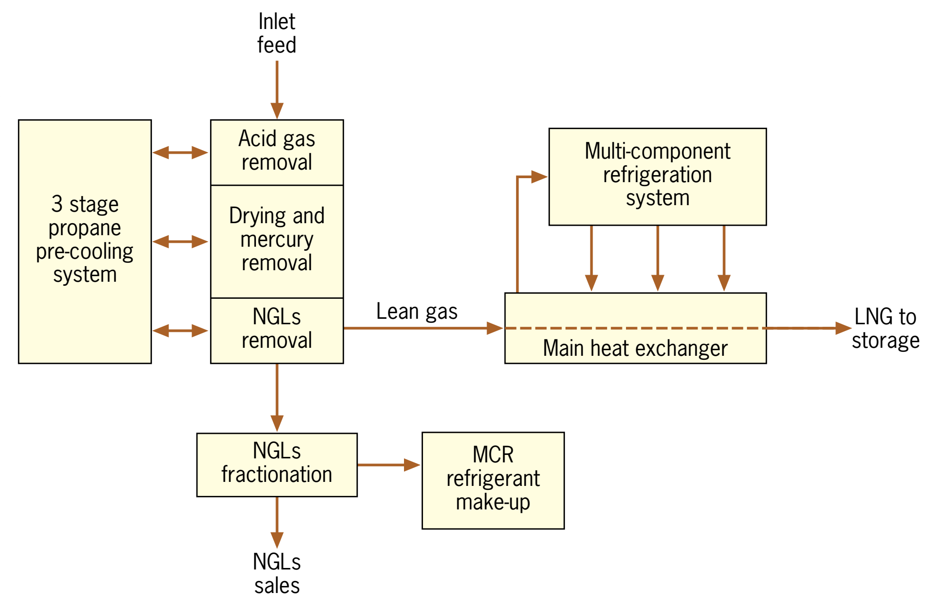


Source: Gas Strategies

Multi-Component Refrigerant (MCR)

The Multi-Component Refrigeration (MCR) process developed by APCI uses a mixture of gases (nitrogen, methane, ethane, and propane). The process was first installed in the LNG plant at Marsa El Brega in Libya which commenced production in 1970. All subsequent plants employing the MCR process use propane to pre-cool the gas to –35° centigrade.

Figure 5: APCI Propane-Precooled Multi-Component Refrigeration process



Source: Gas Strategies

Liquefaction plant costs

Reducing capital costs is a central concern for investors in an LNG project since these costs typically make up over 80% of liquefaction costs. Considerable success has been achieved in recent years with the capital expenditure per tonne of installed capacity per year ($/te/yr) being reduced from $400-500/te/yr in the mid-1980s to under $250/te/yr by 2000. This figure is for fully built up costs, including owner's costs and front-end engineering and design, but excluding financing. These cost reductions have come from a number of factors. The economies of scale have been important as the size of trains has doubled from 2.5 mtpa to 5 mtpa, while technological developments, improved practices in engineering contracting, and changes in design have also made a significant contribution.

Shipping

The LNG ships form a key part of the LNG chain, providing the link between the LNG plant and the LNG buyer. The cargo is carried at atmospheric pressure and is kept in a liquid state through insulation around the tanks. Nevertheless approximately 0.1% to 0.15% of the cargo boils off each day – and in the process helps to keep the remaining cargo at –161° centigrade. The boil-off gas is used in ship's engines. It is possible to re-liquefy the boil-off gas but only one ship (the *LNG Jamal*) currently has these facilities. Normally, a small amount of the cargo (the heel) is left onboard the ship after discharge to keep the tanks cold on the return voyage and avoid the ship having to spend time cooling down on its return to the loading port.

The early LNG ships had capacities of less than 50,000 m^3 but the size has steadily increased over time. The first 125,000 m^3 ship came into service in 1975. In early 2002, the largest ship in operation had a capacity of just under 140,000 m^3 and the largest on order was 145,000 m^3. All but one of the ships that were on order in April 2002 were in the 135,000 m^3 to 145,000 m^3 range that has become the standard size of LNG ships. There are designs available for much larger carriers (200,000 m^3 and larger) but limits on the size of ship most terminals can accept means that a ship of this capacity would not offer its owners the flexibility to trade LNG widely.

Larger ships are generally preferred since they offer economies of scale compared with smaller capacity ships. However, a number of smaller ships (of around 20,000 m^3 capacity) are used to deliver LNG to medium-sized gas companies in Japan, and in the Mediterranean some of the terminals that were built in the 1960s and early 1970s have limitations on the size of ship they can accept. In April 2002, only one of more than 50 ships on order had a capacity of less than 135,000 m^3. That ship was ordered by Gaz de France from the Chantiers d'Atlantique yard in France. It is also unique in having diesel engines. All the other ships in operation and on order are powered by steam turbines.

Most of the 128 LNG ships in operation and 50+ on order at the beginning of 2002 were of the Kvaerner Moss or the Membrane design. Four of the very earliest ships that remain in operation use the Conch self-supporting tank design and two more modern ships use the SPB (Self-supporting Prismatic) system developed by Ishikawajima Harima Industries (IHI) in Japan. The two most common designs are considered below.

The Kvaerner-Moss design

The Kvaerner-Moss system consists of spherical tanks constructed from aluminium alloy (two early ships had tanks made from 9% nickel steel). The tanks are supported around the equator by a cylindrical skirt, welded to the ship's hull. Most of the Kvaerner-Moss ships in operation have between 4 and 6 tanks.

The Membrane designs

There are two different Membrane systems, the Gaztransport and the Technigaz designs. In both, the tanks are built into the hull of the ship with the cryogenic lining of the membrane tank bearing the cargo load and transmitting it to the vessel's hull. Initially these two designs were in competition with each other but the two companies merged in 1994 to become Gaztransport & Technigaz (GTT). A ship owner can specify which of the two techniques he wishes to use since both are still available. Recently, GTT has developed a new membrane design, which will be used in the ship being built for Gaz de France and which, by reducing the thickness of the support and insulation, increases the cargo capacity of the ship marginally without increasing its external dimensions.

LNG ship prices

The prices of LNG ships have varied considerably over time, driven by competition amongst the shipyards able to build this type of ship. The demand for very large crude oil carriers (VLCCs) can also be an important factor since they are often in competition for the same construction berths. In the late 1980s and early 1990s, the cost of a 135,000 m^3 ship reached over $250m but increased competition amongst the ship-yards in 2000 and 2001, and changes in foreign currency exchange rates, resulted in prices falling to around $170m. The prices for Kvaerner-Moss and Membrane ships are generally similar.

Regasification

The ships deliver their cargoes to an LNG receiving terminal where they are unloaded and stored before being regasified and transmitted by pipeline to the end-users. The volume of storage provided depends on a number of factors, including the size of ships being unloaded, the level and variability of demand for regasified LNG and the requirement to provide back-up stocks for strategic reasons. In most cases terminals have the storage capacity for at least two ship-loads of LNG, but in cases where stocks have to be held for strategic reasons or to provide back-up for seasonal swings in demand, the capacity can be well in excess of that level. The terminal with the largest storage capacity is Sodegaura in Japan with a capacity of 2.66 million m^3 of LNG, equivalent to about twenty ship-loads.

Regasification is a much simpler process than liquefaction. The LNG is heated using seawater in open-rack vaporisers or by burning some of the gas in submerged combustion vaporisers. Typically 2 to 3% of the gas is used or lost in the regasification terminal.

The capital costs of receiving terminals vary widely depending, in particular, on the amount of storage and the location. Terminals can cost as little as $200m for 3 mtpa of capacity but can exceed $1bn if the location costs are high and additional storage has to be provided for strategic reasons.

Chapter 3: Project structures

Although the process of producing, liquefying, shipping and regasifying LNG is not particularly complex, the large volumes of gas required, the high levels of capital cost incurred, and the number of stages in the physical supply chain involved, typically result in a complex commercial structure for most developing LNG projects. This chapter examines the commercial structures currently in use to finance and develop LNG projects.

Defining project structure

The definition of the project's commercial structure is a critical stage in the development of any LNG project. The structure has to provide a sound base for the project to be developed and operated. The objectives which have to be addressed in establishing the structure include:

- Creating a stable and sustainable operation
- Sharing the risks and rewards between the stakeholders in an equitable way
- Obtaining finance for the project
- Providing the confidence for buyers to purchase the LNG
- Accessing the appropriate skills
- Satisfying the requirements of the host government
- Minimising the potential for conflict and delay

Each part of the LNG chain is dependent on the others and there has to be an undivided physical link between the gas production and the customer. Should any link fail the whole chain may fail. The income of investors in each part of the chain depends on the other parts, so investors in any one link of the chain cannot afford to ignore what is happening in the other links.

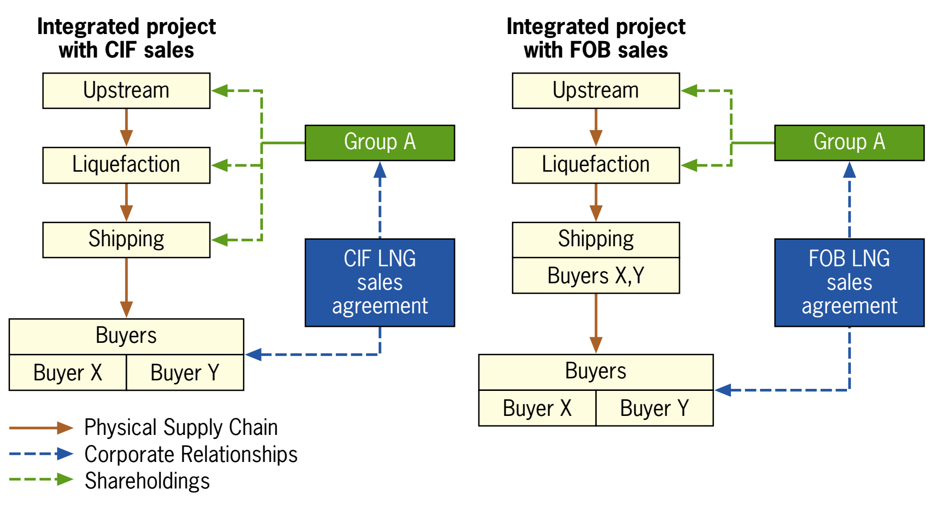
The structure of every LNG project is unique, but the structures can be grouped into three generic models:

- Integrated projects
- Transfer pricing arrangements
- Throughput arrangements

This chapter provides an overview of the generic models and then uses case studies to illustrate each.

Integrated project structures

Figure 6: Integrated LNG project structure



Source: Gas Strategies

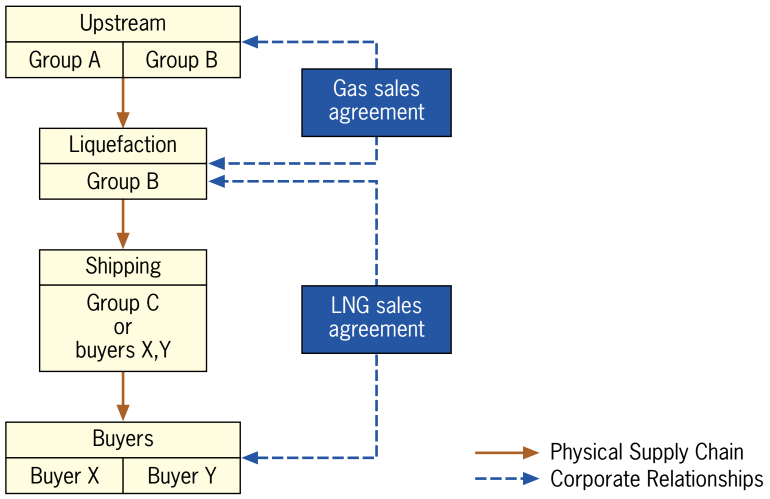
In an integrated project there is common ownership of the gas reserves, liquefaction plant, and, if the project sells on a CIF (cost, insurance, freight)[1] or ex-ship basis, the ships. Four examples of integrated projects are Algeria, Alaska, Australia North West Shelf and RasGas in Qatar. In the first three projects the integration covers the shipping phase as well as the gas production and liquefaction[2]. For example in the Alaskan project the co-venturers, Phillips and Marathon, jointly own the gas reserves, production facilities, liquefaction plant, and the LNG ships. Unlike the other three integrated projects, RasGas sells on an FOB (free on board) basis so the integration only extends to the gas production and the LNG plant, leaving buyers to make their own shipping arrangements. An integrated project has the advantages of aligning partner interests and avoiding the sometimes contentious and time-consuming negotiation of transfer prices between the upstream and the plant, and between the plant and the shipping. It can also make expansion a more straightforward process provided that the original owners have the reserves to support the expansion. If third party gas is required, then agreements to access those reserves will have to be negotiated, which may involve bringing new partners into the project.

[1] LNG (and crude oil) cargoes are typically described as either CIF (cost, insurance, freight) or FOB (free on board). In general terms with a CIF shipment the seller arranges transportation, whereas with a FOB shipment the buyer is responsible for transportation.

[2] The Algerian project is partially integrated at the shipping stage – Sonatrach owns the gas reserves, the LNG plants, and some of the ships used to transport the gas to market. There are also a number of ships in use owned by Sonatrach's customers.

Transfer pricing arrangements

Figure 7: Transfer pricing arrangement LNG project structure



Source: Gas Strategies

In many LNG projects an integrated structure is not an option because the owners of the gas reserves differ from the owners of the LNG plant. In these cases a gas supply agreement has to be negotiated between the owners of the gas reserves and the LNG plant. A key clause in such an agreement will be the transfer price for the gas. In some projects the ownership of the ships differs from the plant and in these cases a transfer arrangement between the plant and the ships is also needed.

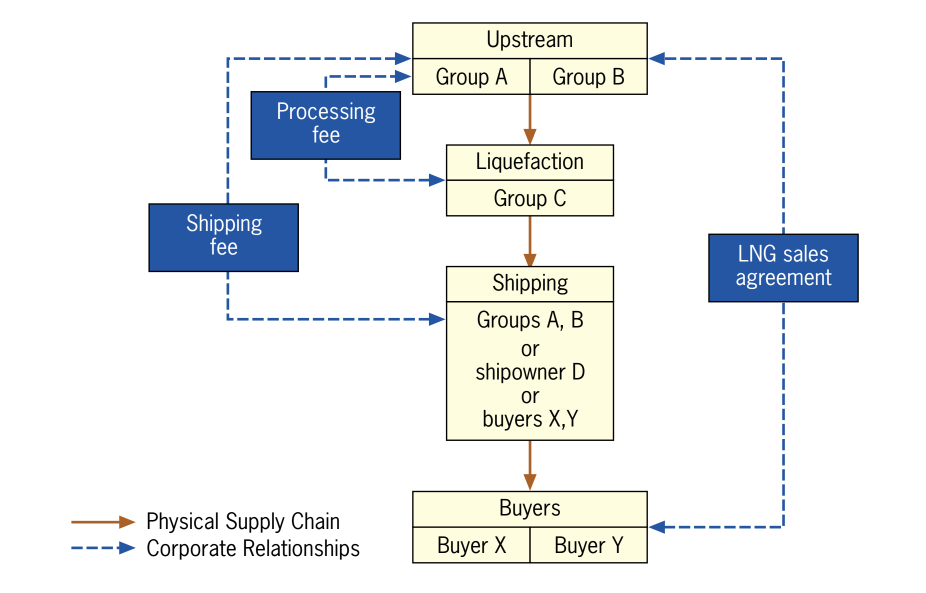
The differences in ownership can arise because of requirements of the host government for upstream production to be managed through production sharing contracts (e.g. Indonesia and Malaysia) or government ownership of gas reserves (e.g. Abu Dhabi and Oman). In some cases, additional partners are brought into the liquefaction plant to access particular skills or knowledge (e.g. Japanese trading houses in Brunei and Malaysia or an LNG buyer in Oman). Differences in ownership in the shipping phase of the project may arise because some of the investors do not want involvement in LNG ships or the host government has aspirations to control the ships.

The transfer price agreed between the upstream and LNG plant owners will be an important factor in determining their respective rates of return. This often results in a major debate about the affordable plant-gate price, the value of the reserves and the returns appropriate to upstream development compared with the liquefaction facilities. Similar considerations can arise in the negotiation of arrangements between the LNG plant and the shipping phase of the project.

Conflicts of interest may arise between partners seen as trying to favour their part of the project. Furthermore, an agreement on the transfer arrangements, reached before start-up, may not stand the test of time. Changing conditions during the life of the project may result in the sharing of rewards not turning out as expected, leaving one or other of the parts of the project feeling that they have not received an appropriate share of the overall project returns.

Throughput arrangements

Figure 8: Throughput arrangement LNG project structure



Source: Gas Strategies

The third form of project structure is a throughput arrangement where the upstream producers pay a tolling fee to use the LNG plant and then market the LNG on their own behalf. There are currently no LNG projects operating on this basis. However, in the Atlantic LNG project in Trinidad, the structure adopted for trains 2 and 3, which will come into operation in 2002 and 2003, is in effect a throughput arrangement, although the joint company, Atlantic LNG, is the actual seller of the LNG. It has been agreed that for any future LNG trains at the plant the gas producers will sell the LNG themselves and pay a tolling fee to Atlantic LNG. The Snøhvit project in Norway, which is scheduled to come on stream in 2006, is structured as a venture in which each shareholder has the right to market its share of the LNG. Most of the shareholders have agreed to sell jointly but Gaz de France and TotalFinaElf have elected to lift their shares of the production directly.

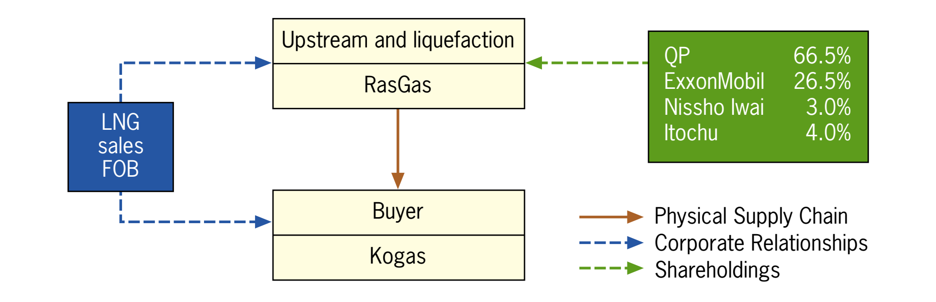
The Indonesian LNG projects (Arun and Bontang) exhibit some of the features of a throughput agreement but in these cases Pertamina, rather than the upstream production sharing contractors (PSCs), is the marketer of the LNG. Pertamina owns the LNG plants and charters the CIF ships, but operates them as cost centres. The

PSCs receive a netback from LNG sales after deducting the costs of liquefaction and shipping. Although the PSCs do not actually sell their own LNG, Pertamina involves them in the marketing. Pertamina's project income comes from its share of the production rather than its investment in the liquefaction plant.

Project structures – case studies

RasGas trains 1 & 2

Figure 9: RasGas trains 1 and 2 project structure



Source: Gas Strategies

RasGas trains 1 and 2 is an integrated project. RasGas integrates both plant and reserves, but sells FOB. A Korean consortium has the option to acquire a 5% stake in RasGas trains 1 and 2, which would decrease the shares of Qatar Petroleum (QP) by 3.5% and ExxonMobil by 1.5%, but this right had not been exercised as at 1st April 2002.

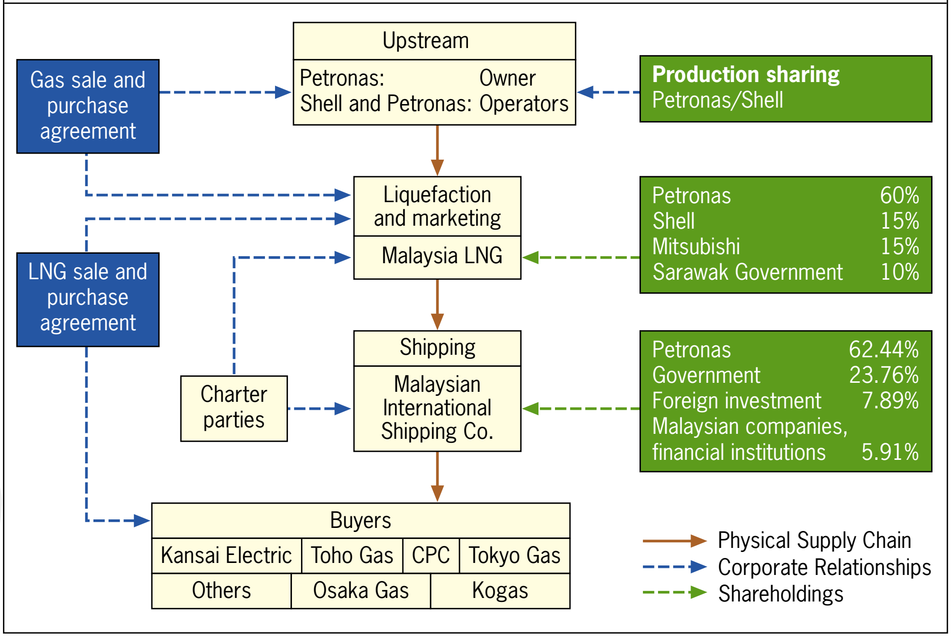
A third train is under construction and will be commissioned in 2004. The shareholdings in that train will probably be different from those in trains 1 and 2 although QP and ExxonMobil will remain the major shareholders.

Malaysia LNG Dua

The MLNG Dua project is an example of a transfer pricing structure. The upstream producers, Shell and Petronas Carigali, produce gas through a production sharing arrangement, and sell it to the plant operator, MLNG Dua, a joint venture between Petronas, Shell, Mitsubishi, and the Sarawak Government. MLNG Dua sells the LNG and arranges shipping through the Malaysian International Shipping Company (MISC). A similar structure was used in the first Malaysian LNG project, MLNG Satu, and in MLNG Tiga, currently under construction, but the upstream and plant shareholdings and the buyers vary between the projects.

PROJECT STRUCTURES

Figure 10: Malaysia LNG Dua project structure

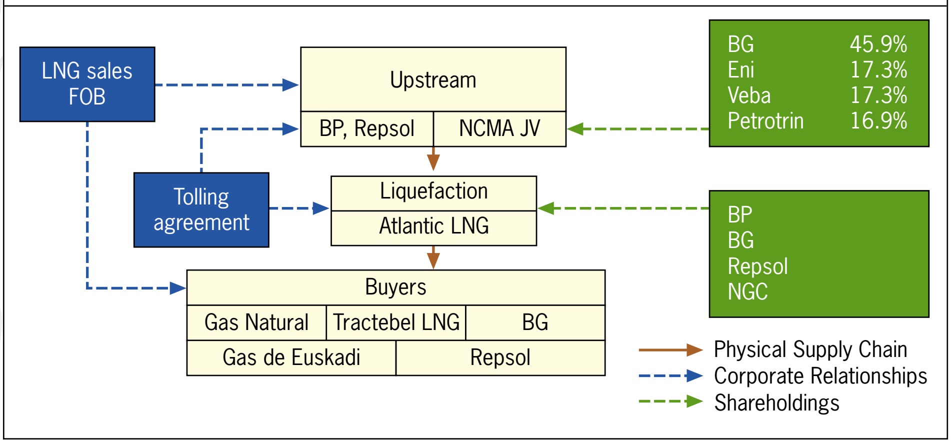


Source: Gas Strategies

Atlantic LNG trains 2 & 3

The structure adopted for trains 2 and 3 at Atlantic LNG in Trinidad, which are due to come into operation in 2002 and 2003, is the closest to a throughput arrangement amongst the projects currently in operation or under construction. Although Atlantic LNG is the signatory of the LNG Sales and Purchase Contracts, BP/Repsol's revenues will be derived from sales to the Spanish buyers (Gas Natural, Gas de Euskadi, and Repsol) and revenues for the BG-led North Coast Marine Area Joint Venture (NCMA JV) from sales to the US market (BG and Tractebel LNG). BG buys FOB. Sales to Spain will be in Repsol ships, sales to BG in BG ships. The revenues received by the upstream producers will be a netback from prices paid by the buyers after deducting a tolling fee which is calculated to earn an agreed rate of return on investment in the LNG plant.

Figure 11: Atlantic LNG trains 2 and 3 project structure



Source: Gas Strategies

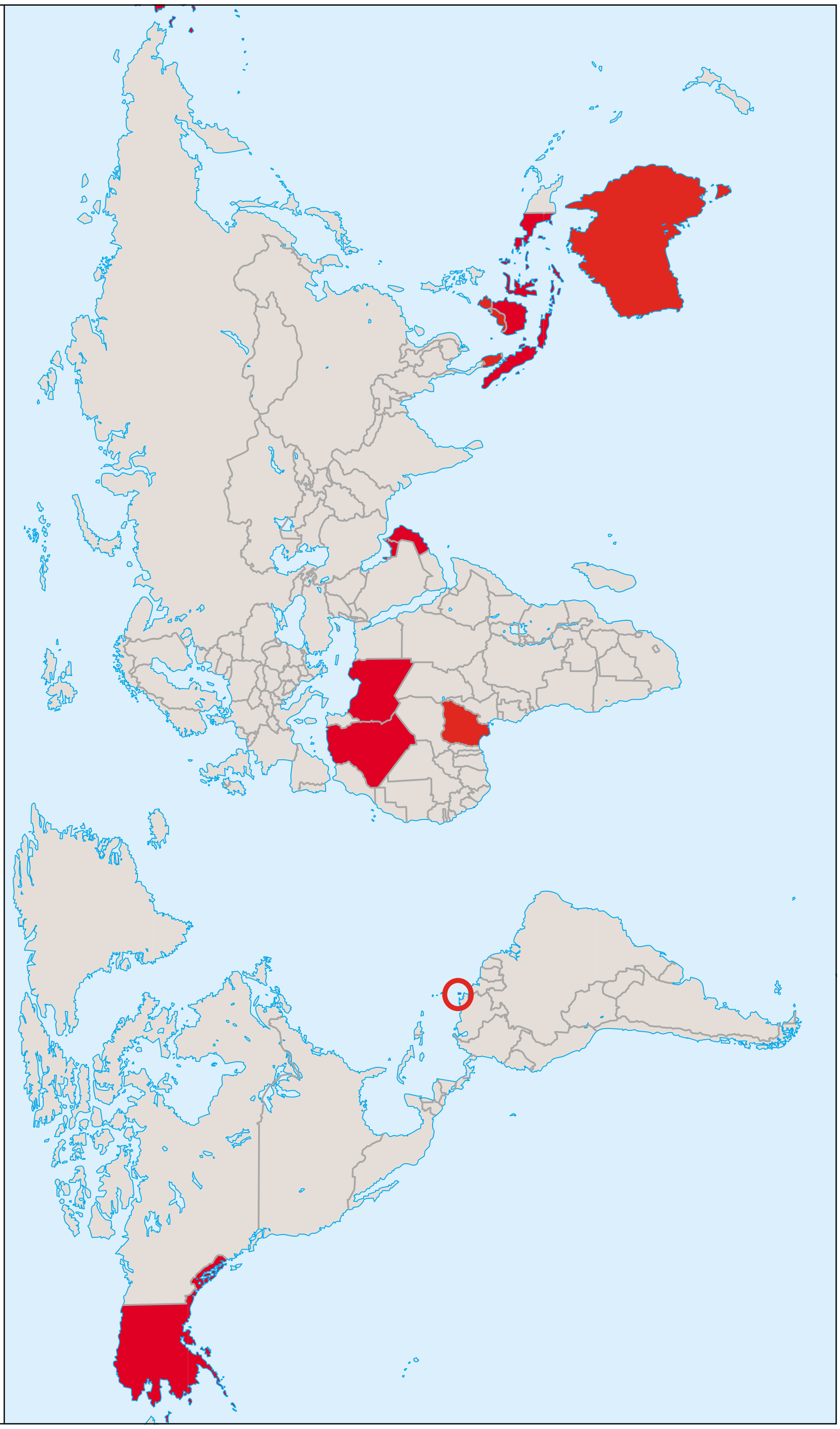
Chapter 4: Sources of LNG

Although gas reserves in any location could in theory be used for LNG production, certain factors are particularly conducive to the choice of LNG rather than pipelines as the means of transporting gas to market. Large gas reserves located sufficiently far from potential markets to discourage investment in pipelines are particularly suitable for LNG development. Other characteristics of suitable gas reserves for LNG projects include the presence of non-associated gas, the proximity of gas reserves or production facilities to the coast, and the potential for long-term production at a high level. These factors have had a major impact on the choice of location for LNG projects and have led to the concentration of LNG projects within three major supply envelopes: Asia-Pacific (notably on the island of Borneo and off the north-west coast of Australia), the Middle East and the Atlantic basin. This chapter examines current and future LNG projects in each of these regions and considers potential new supply sources.

Overview of LNG supply sources

At the beginning of 2002, there were 18 LNG plants in operation in 12 countries worldwide. Total production capacity was just over 120 mtpa and actual production in 2001 amounted to 105 mt. Production capacity will increase to over 160 mtpa by 2005 or 2006 as the nearly 40 mtpa of facilities under construction are commissioned. Plans have been announced for the development of 170 mtpa of additional capacity. In the unlikely event that all these projects are developed, a further 10 countries will join the ranks of LNG exporters.

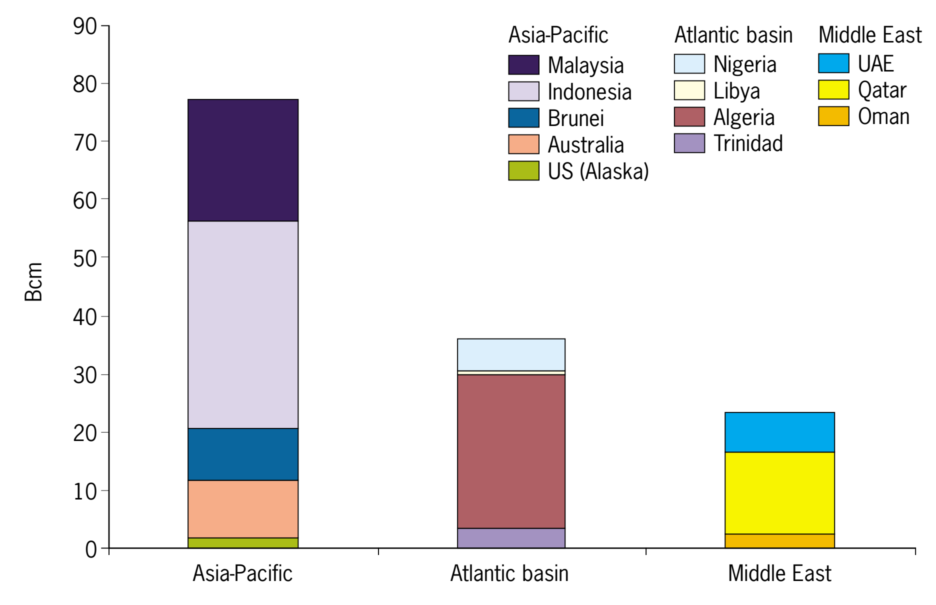
Figure 12: Current LNG exporting states



Source: Gas Strategies

Around half of the world's existing LNG production capacity is in the Asia-Pacific region, with the four LNG plants on the island of Borneo (Malaysia Satu and Dua, Brunei LNG and Bontang, Indonesia) alone accounting for about 45% of the total. Approximately, 22% of the capacity in operation in early 2002 is in the Middle East and the remaining 28% is in the Atlantic basin.

Figure 13: LNG Exports by region, 2000



Source: BP Statistical Review of World Energy, 2001

The Atlantic basin

Table 1: Atlantic basin LNG capacity, April 2002

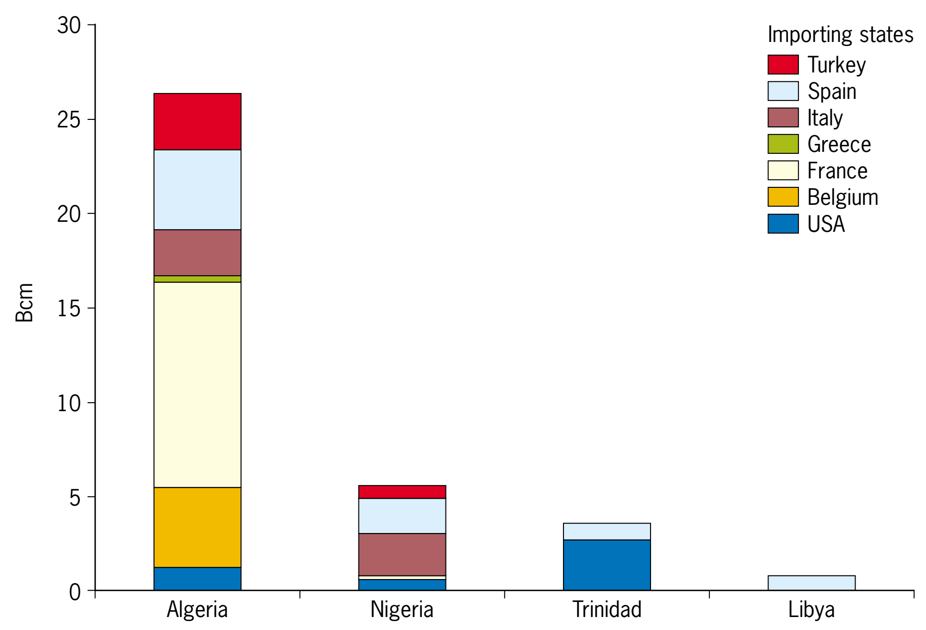
Plant	*Country*	*Capacity (mtpa)*	*Start up*
GL4Z	Algeria	0.9	October 1964
Marsa El Brega	Libya	2.6	April 1970
GL1K	Algeria	5.1	December 1972
GL1Z	Algeria	8.0	February 1978
GL2Z	Algeria	8.4	July 1981
Atlantic LNG	Trinidad & Tobago	3.0	April 1999
Bonny Island	Nigeria	5.9	September 1999

Source: Gas Strategies

The Atlantic basin is a broad term used to cover LNG projects on both sides of the Atlantic, such as those in Nigeria and Trinidad, as well as North African LNG projects on the Mediterranean Sea. Algeria is the largest LNG producing state in the Atlantic basin, although rapid expansion in Nigeria and Trinidad may go some way to challenging its position. Algeria was the only major LNG supplier to Europe and the USA from the start-up of its first LNG plant in 1964 until the 1990s. Three further LNG facilities were commissioned in Algeria in the 1970s and early 1980s, taking its total production capacity to over 22 mtpa. The only other LNG supplies for the European market came from the small Marsa El Brega plant in Libya and, in the 1990s, from short-term and spot cargoes exported from the Middle East and Australia. The Marsa El Brega plant started up in 1970 with a design capacity of 2.6 mtpa. This level of production was reached in 1977 but since then technical problems have reduced its effective capacity and in 2000 it exported only 0.6 mt of LNG.

Several attempts at developing further Atlantic basin LNG supply projects in the 1970s, 1980s and early 1990s failed for a variety of reasons, including gas prices in Europe and the USA that would not remunerate the investment in gas production, liquefaction and ships. However, reductions in LNG production costs in the 1990s improved the economic viability of new projects and, in 1999, the first new LNG plants for nearly 20 years serving Atlantic basin markets started-up in Trinidad and Tobago and in Nigeria. The Atlantic LNG plant in Trinidad was the first new LNG project since the Kenai plant in Alaska to be developed as a one-train plant. The commissioning of Nigeria LNG's plant at Bonny Island meant that plans for an LNG project in Nigeria had finally been realised more than 30 years after first being proposed.

Figure 14: Atlantic basin LNG exports, 2000



Source: BP Statistical Review of World Energy, 2001

Even before the plants in Trinidad and Nigeria were commissioned, plans were already advanced for the construction of new trains at both facilities. By early 2002, construction was well advanced, with the expectation that the two new trains in Trinidad and the one new train in Nigeria will be commissioned by early 2003. A commitment was announced in March 2002 to a further two trains at the Nigeria LNG plant that will take its capacity to 17 mtpa by 2005, only 6 years after production first started. The only greenfield plant under construction in early 2002 to serve Atlantic basin markets was at Damietta in Egypt, where Union Fenosa and its Egyptian partner have committed to a single 4.97 mtpa train that is scheduled for completion in 2004. In total, some 22 mtpa of new capacity was under construction in the Atlantic basin at the end of the first quarter of 2002.

Table 2: Atlantic basin LNG capacity under construction, April 2002

Plant	*Country*	*Capacity (mtpa)*	*Start up*
Atlantic LNG Train 2	Trinidad	3.3	Q3 2002
Nigeria LNG Train 3	Nigeria	3.0	End 2002
Atlantic LNG Train 3	Trinidad	3.3	Q1 2003
Damietta	Egypt	5.0	2004
Nigeria LNG Trains 4 and 5	Nigeria	8.0	2005

Source: Gas Strategies

The revival of interest and activity in Atlantic basin LNG has resulted in the announcement of plans for further expansions of existing plants and for greenfield developments on both sides of the Atlantic. Table 3 below summarises the planned facilities, their potential capacity and the dates by which the developers have said they are targeting start up.

Table 3: Atlantic basin proposed LNG capacity, April 2002

Plant	*Country*	*Capacity (mtpa)*	*Start up*
Snøhvit	Norway	4.3	2006
Atlantic LNG Train 4	Trinidad	4.8	2005
Idku	Egypt	3.6	2005
Damietta Train 2	Egypt	5.0	2005
Idku Train 2	Egypt	3.6	2006
Nigeria LNG Train 6	Nigeria	4.0	2006+
Atlantic LNG Trains 5 & 6	Trinidad	9.6	2006+
Luanda	Angola	4.0	2006+
Paria Peninsula	Venezuela	4.0	2006+
Kudu	Namibia	5.0	2006+
Brass River	Nigeria	5.0	2007+
Arzew	Algeria	4.0	Not yet known
Western Niger Delta	Nigeria	8.0	Not yet known

Source: Gas Strategies

The potential new capacity amounts to over 60 mtpa. Three of the projects listed above, Snøhvit in Norway, Idku in Egypt and the fourth train at the Atlantic LNG plant in Trinidad, were at an advanced stage of development in early 2002 and commitment was expected to be made during the year. The timing of commitment to the other projects is more uncertain and some may be delayed or cancelled. However, LNG supply capacity in the Atlantic basin could potentially reach over 100 mtpa by 2010.

The Middle East

Table 4: Middle East LNG capacity, April 2002

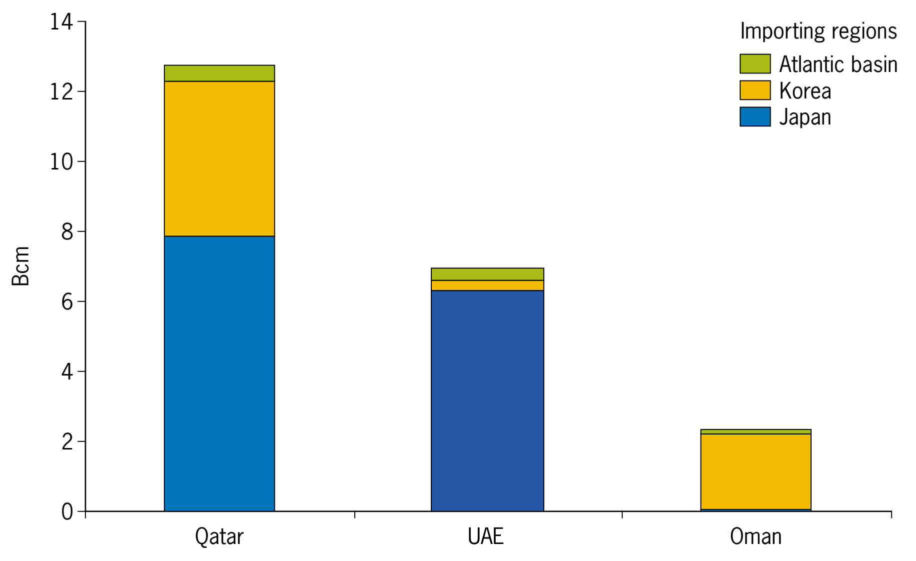
Plant	*Country*	*Capacity (mtpa)*	*Start up*
Das Island	Abu Dhabi	5.7	April 1977
Qatargas	Qatar	7.7	December 1996
RasGas	Qatar	6.4	May 1999
Qalhat	Oman	6.6	April 2000

Source: Gas Strategies

The Middle East's first LNG plant came on stream in Abu Dhabi in 1977. However, despite the abundance of low cost gas reserves, the region only emerged as a major LNG producer in the 1990s with the expansion of the Abu Dhabi plant and the commissioning of greenfield facilities in Qatar and Oman.

All the existing projects in the region were developed to supply consumers in Japan and Korea, but the uncertain demand prospects in those markets has caused Middle Eastern LNG producers to look at alternative markets. India appeared to be a highly prospective market, given its proximity to the Middle East, but its emergence as an LNG importer has been much slower than expected. As a result, the producers in the region are turning to markets West of Suez. Initially the main sales to Europe and the USA were made on a spot or short-term basis, but more recently Qatar, Abu Dhabi and Oman have all signed medium or long-term contracts to supply markets in southern Europe.

Figure 15: Middle East LNG exports, 2000



Source: BP Statistical Review of World Energy, 2001

As figure 15 shows, Japan and Korea remained the dominant markets for Middle Eastern LNG in 2000, but each country sold some of its surplus LNG into Atlantic basin markets. Oman's LNG plant was not commissioned until April 2000, so its production was in the build-up phase in 2000. Overall, Middle Eastern production capacity was just over 26 mtpa in early 2002 and a further 6.2 mtpa of capacity was under construction in Qatar, through the debottlenecking of the Qatargas plant and the construction of a third train at the RasGas plant.

SOURCES OF LNG

Table 5: Middle East LNG capacity under construction, April 2002			
Plant	*Country*	*Capacity (mtpa)*	*Start up*
RasGas Train 3	Qatar	4.7	2004
Qatargas (debottlenecking)	Qatar	1.5	2002-2005

Source: Gas Strategies

The additional capacity will take the regional total to over 32 mtpa by 2005. As shown in table 6, plans have been announced that would result in a further doubling of production capacity by 2010 and there is the potential for even more additions to capacity if markets can be found. Qatar has plans for an additional train at both its Qatargas and RasGas facilities to supply southern European and Indian markets. Qatar has enormous uncommitted gas reserves in its North field and space at the Ras Laffan site for at least four more LNG trains so the ability to expand production further is probably only limited by the market and the Qatari Government's policy for the amount of LNG it eventually wants to produce. Oman is considering a third train at its Qalhat plant, while Yemen and Iran both have plans for greenfield facilities. Iran, with its abundant gas reserves, is evaluating the feasibility of up to four plants to be supplied from the South Pars field.

Table 6: Middle East proposed LNG capacity, April 2002			
Plant	*Country*	*Capacity (mtpa)*	*Start up*
RasGas Train 4	Qatar	4.8	2005
Qatargas Train 4	Qatar	4.8	2005+
Qalhat	Oman	3.3	2005+
Bal Haf	Yemen	6.2	2005+
Asaluyeh I	Iran	8.0	2006+
Asaluyeh II	Iran	8.0	2006+

Source: Gas Strategies

Asia-Pacific

Table 7: Asia-Pacific LNG capacity, April 2002

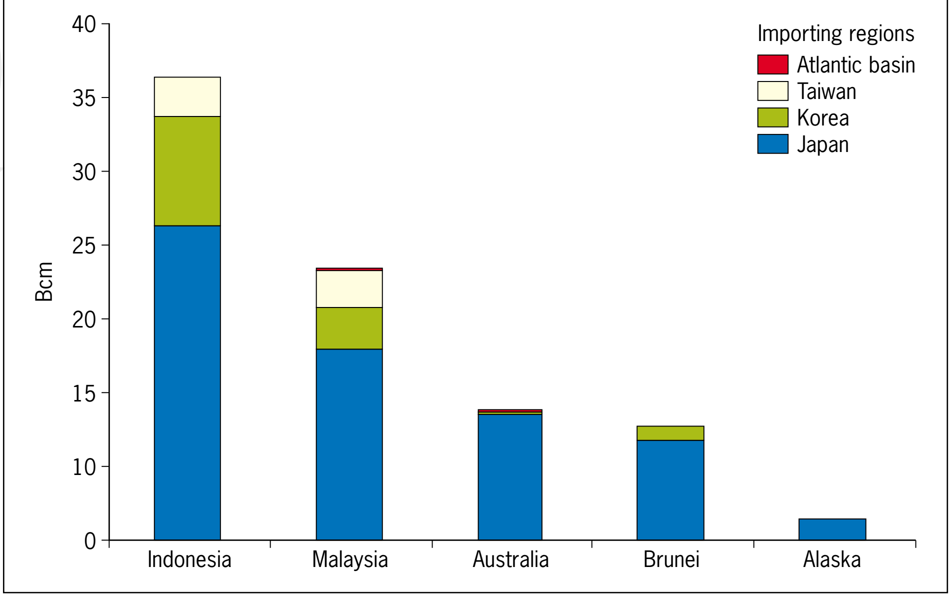
Plant	*Country*	*Capacity (mtpa)*	*Start up*
Kenai	US (Alaska)	1.4	October 1969
Lumut	Brunei	7.2	December 1972
Bontang	Indonesia	22.6	August 1977
Arun*	Indonesia	6.8	October 1978
Satu	Malaysia	7.6	January 1983
North West Shelf	Australia	7.5	July 1989
Dua	Malaysia	7.8	March 1995

*Production limited by availability of reserves
Source: Gas Strategies

Asia-Pacific is currently the major LNG production and consumption region. The proximity to the Asian LNG markets of Japan, Korea and Taiwan has resulted in LNG production in the Asia-Pacific region growing rapidly following the start-up of the first facility in Alaska in 1969. By early 2002, capacity had reached just over 60 mtpa despite two trains at one of the largest plants, Arun in Indonesia, being shut down because of the failure to find new gas reserves to replace declining production from its main supply source, the giant Arun field. In table 7, the capacity of the plant is based on the contracted volume of LNG rather than the production capacity of the four Arun trains that remain in operation. It is expected that further trains at the Arun plant will be closed down as LNG sales contracts expire in 2004 and 2007. The plant is expected to be completely mothballed around 2010. The Kenai project is also reported to be running short of gas and the existing sales contract may not be renewed when it expires in 2009. The remaining LNG plants listed in table 7 are expected to continue in production until after 2015.

Japan is the main market for projects in operation in the Asia-Pacific region but Malaysia, Indonesia and Brunei also supply Korea on a long-term basis. Both Australia and Malaysia also supplied a small volume of LNG to Atlantic basin markets in 2000.

Figure 16: Asia-Pacific LNG exports, 2000



Source: BP Statistical Review of World Energy, 2001

As shown in table 8, a further 11 mtpa of capacity is under construction in Malaysia and Australia. Malaysia Tiga is a new plant being constructed at the same location as the Malaysia Satu and Dua facilities and sharing some of the infrastructure. In Australia, the North West Shelf project is adding a fourth train to supply Japanese buyers.

Table 8: Asia-Pacific LNG capacity under construction, April 2002

Plant	*Country*	*Capacity (mtpa)*	*Start up*
Tiga	Malaysia	6.8	Early 2003
North West Shelf Train 4	Australia	4.2	July 2004

Source: Gas Strategies

There are a large number of expansions and new greenfield projects being planned in the region. Several of these are in Australia, based on major gas discoveries that have been made off the north and north-west coasts. Included in the list of possible Australian projects is what could be the world's first floating LNG project, to develop reserves in the Sunrise gas field. Indonesia has three possible projects, including the addition of a further train to the Bontang plant, a new project in Tangguh, which it is hoped will provide a second Indonesian LNG centre to replace the Arun facility, and the perennial Natuna project, where the high carbon dioxide content of the natural gas adds to both the technical complexity and the cost of development.

The list of potential projects includes a new greenfield development on Sakhalin Island, just north of Japan, which would be the first LNG project in Russia, the world's largest gas exporter. The Brunei project is planning a sixth train towards the end of the decade and there are plans for an LNG project based on the reserves on the Alaskan North Slope. However, a pipeline to deliver the gas to the US market is also being evaluated.

As shown in table 9, the total planned and possible capacity in the Asia-Pacific region amounts to nearly 60 mtpa. The first six projects listed in the table, with a combined capacity of 30 mtpa, are all being actively progressed and technical work has reached the stage where commitment is possible within the next twelve months. However, for most of these projects the main issue is the lack of buyers prepared to make a long-term commitment that would underpin the investment.

Table 9: Asia-Pacific proposed LNG capacity, April 2002

Plant	*Country*	*Capacity (mtpa)*	*Start up*
Tangguh	Indonesia	6.0	2006+
Bontang Train I	Indonesia	3.0	2005
Darwin LNG	Australia	3.0	2006
North West Shelf Train 5	Australia	4.2	2005+
Sakhalin	Russia	9.6	2006+
Sunrise (Floating LNG)	Australia	5.0	2006+
Gorgon	Australia	8.0	2006+
Brunei LNG Train 6	Brunei	4.0	2008
Alaska North Slope	USA	7.0+	2007+
Natuna	Indonesia	10.0+	?

Source: Gas Strategies

Potential new supply regions

Although the majority of new projects are within the existing supply envelopes and are targeted to existing markets in Asia-Pacific and the Atlantic basin, there is one significant new LNG producing region which could open up a new LNG market. The Pacific coast of South America emerged as a potential LNG source during 2001. Both Peru and Bolivia have natural gas reserves well in excess of their domestic needs. The rise in US gas prices during 2000 and 2001, together with increasing gas demand in Mexico, has focused attention on the prospects for LNG imports into the west coast of North America. Baja California has emerged as the location for a number of LNG import terminals targeted at supplying gas markets in northern Mexico and California.

An LNG plant located on the Pacific coast of South America would be well placed to supply such a terminal since the shipping distance would be much shorter than from the other side of the Pacific. However, the gas reserves in Bolivia and Peru are located on the eastern side of the Andes so the gas would have to be piped across the mountains before being liquefied. The Camisea field in Peru is already being developed and a pipeline to Lima on the Pacific coast is under construction. An LNG plant is planned in the south of Peru supplied by the same pipeline. Bolivia lacks a coastline so an LNG plant would have to be located in northern Chile or southern Peru. The two facilities currently being discussed would have a total capacity of 11mtpa.

Table 10: Pacific South America proposed LNG capacity, April 2002

Plant	*Country*	*Capacity (mtpa)*	*Start up*
Pacific LNG	Bolivia – Chile/Peru	7.0	2006+
Camisea	Peru	4.0	2006+

Source: Gas Strategies

World LNG supply outlook

Table 11: World LNG production capacity, April 2002

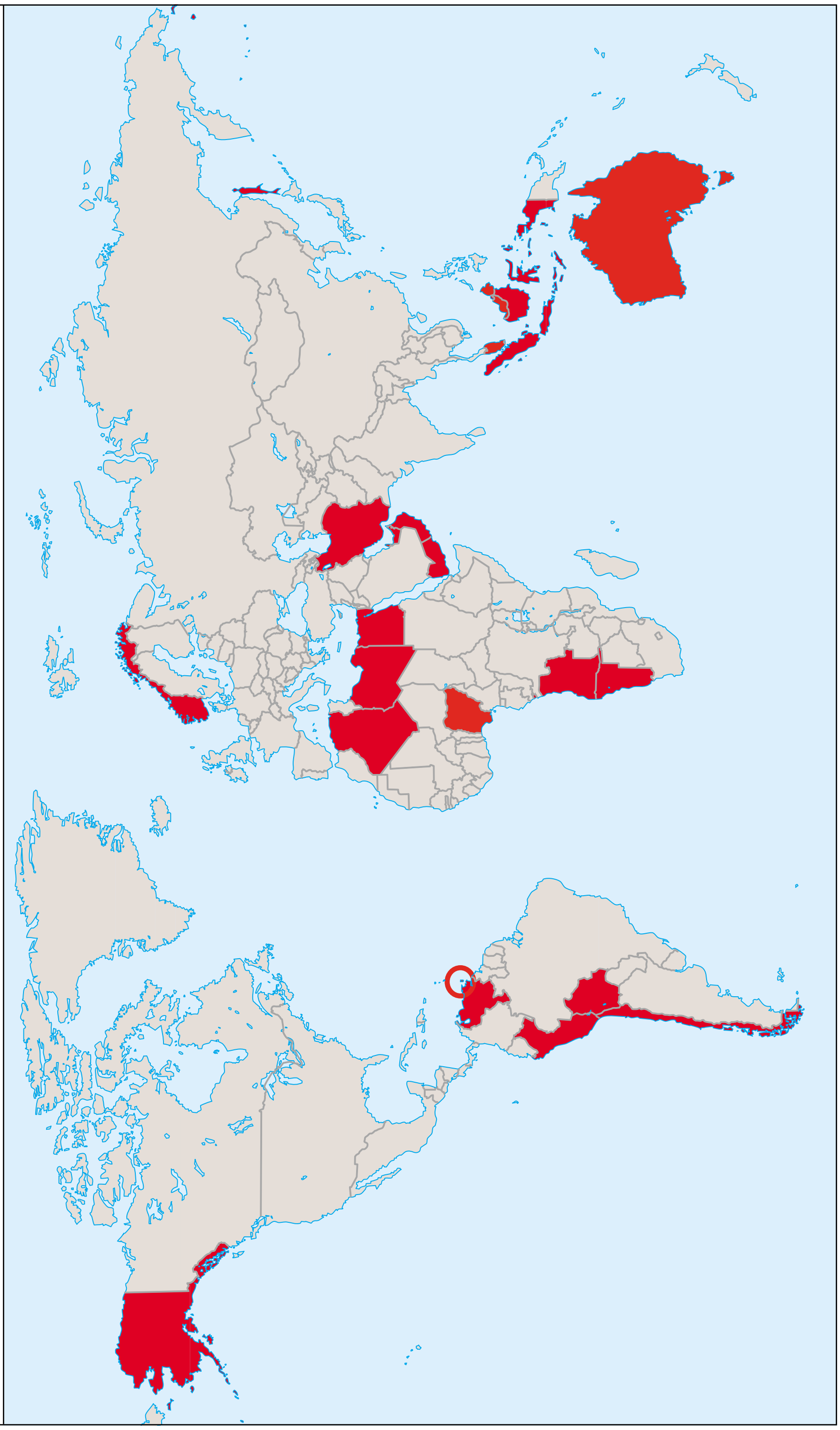
Region	*Capacity in operation (mtpa)*	*Capacity under construction (mtpa)*	*Capacity proposed (mtpa)*	*Total potential capacity (mtpa)*
Atlantic basin	33.8	22.5	64.9	121.2
Middle East	26.4	6.2	35.1	67.7
Asia-Pacific	60.9	11.0	59.8	131.7
Pacific South America	0	0	11.0	11.0
Total	**121.1**	**39.7**	**170.8**	**331.6**

Source: Gas Strategies

Table 11 summarises the estimated capacity of the LNG plants listed in tables 1 to 10. It shows that currently available capacity of just over 120 mtpa is set to increase by one-third when all the projects under construction are commissioned. This should be achieved by 2005 or 2006. In addition further capacity is being planned which could more than double the total to over 300 mtpa.

The planned projects include expansion of many of the projects now in operation. There are a number of greenfield developments in countries that currently do not export LNG. Figure 17 shows how these countries span the four corners of the globe.

Figure 17: Planned and possible new export capacity



Source: Gas Strategies

The supply picture is therefore one of enormous potential growth in LNG supply. LNG generally offers the best opportunity for early monetisation of remote natural gas discoveries and hence reserves owners and host governments are actively promoting LNG developments. The lack of buyers prepared to commit to purchase the LNG at a price that will remunerate the investment is in many cases the main barrier to a final investment decision. Consequently, we must now turn to look at LNG markets.

Chapter 5: LNG markets

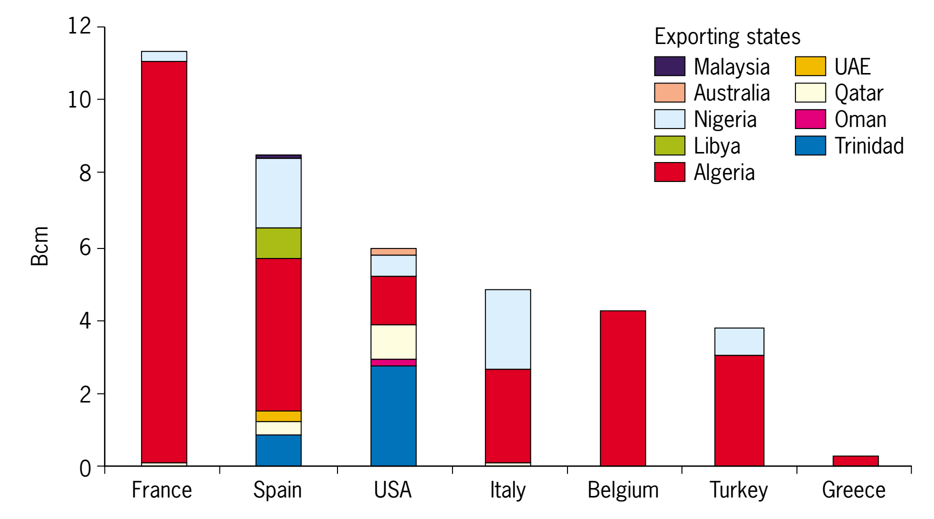
A key issue in the development of LNG projects is the need to find a suitable market for the gas, and in particular a buyer prepared to sign a long-term purchase contract at a price sufficient to justify huge investments in LNG production. This chapter analyses the current markets for LNG and examines the outlook for existing and new LNG markets around the world.

Current markets

World LNG demand reached 105 mt in 2001. LNG demand is currently concentrated in two major regions: Asia-Pacific (Japan, Korea and Taiwan) which accounted for 71% of the demand, and the Atlantic basin (Europe and the USA) which consumed the remaining 29%. The international trade of LNG started in the Atlantic basin with exports from Algeria to the UK in 1964, exports to France from 1965, and later to the USA, Italy, Belgium and Spain. Japan became an LNG importer in 1969 following the start-up of deliveries from Alaska and for much of the next three decades the fastest growth in LNG demand was in the Asia-Pacific region, initially through increasing imports by Japanese buyers. Korea (1986) and Taiwan (1990) later joined Japan as LNG importers. However, the last five years have seen a resurgence of growth in the Atlantic basin as Algeria increased its production following a revamp of its facilities, and Trinidad and Nigeria became the first new LNG producers in the Atlantic basin for nearly 30 years. In addition Turkey, Greece, Portugal and Puerto Rico began to import LNG. Between 1996 and 2001, LNG demand grew by nearly 12% per year in the Atlantic basin, compared with 5% per year in the Asia-Pacific region.

Atlantic basin

Figure 18: Atlantic basin LNG imports, 2000



Source: BP Statistical Review of World Energy, 2001

The main LNG markets in the Atlantic basin are in Europe (France, Spain, Belgium, Turkey, Portugal, Italy and Greece), with the US, which has been importing LNG since the 1970s, currently a much smaller importer. Puerto Rico in the Caribbean (whose LNG imports are included in the US statistics) started to import LNG in 2000.

The European market

As table 12 shows, European LNG imports totalled 23.3 mt in 2000, with France the largest importer (8 mt). New importers in 2000 were Portugal, which is importing LNG via Spain until the completion of its LNG terminal at Sines, and Greece, which commissioned a terminal at Revithoussa in 2000.

Table 12: European LNG imports, 2000

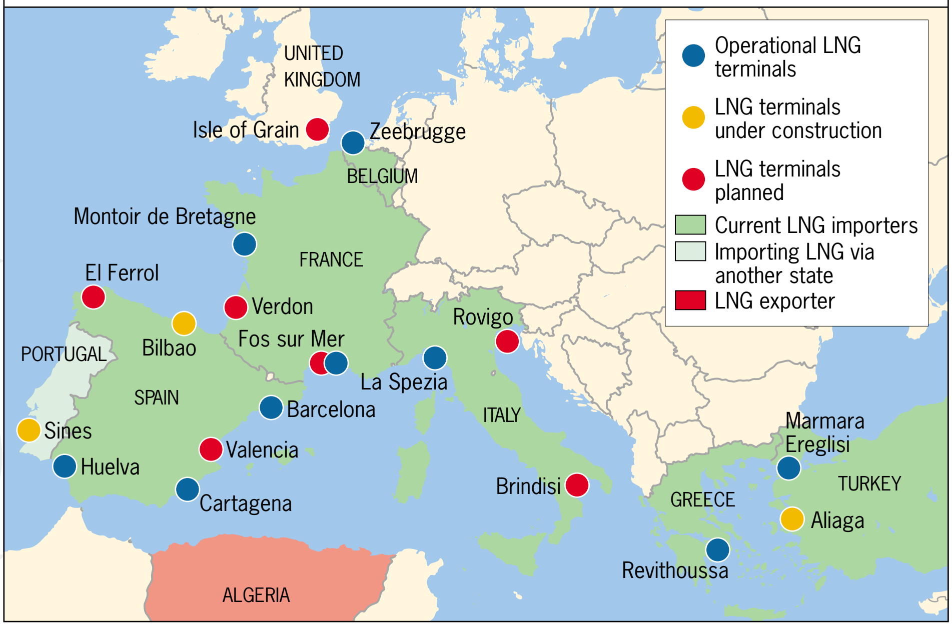
Country	*Million tonnes*
France	8.0
Spain	5.9
Italy[1]	3.4
Belgium	3.0
Turkey	2.6
Portugal[2]	0.3
Greece	0.2
Total[3]	**23.3**

[1] Includes 1.6 mtpa of Nigerian LNG imported via France
[2] Imported via Spain
[3] Figures may not add up due to rounding
Source: BP Statistical Review of World Energy 2001; Gas Strategies

Atlantic basin supply is dominated by Algerian exporter Sonatrach, which supplies to all the Atlantic basin LNG terminals with the exception of Puerto Rico. In 2000 it supplied around 67% of Atlantic basin demand and over three quarters of European imports. Most of the Atlantic basin LNG import infrastructure was developed for Algerian LNG, with many of the supply contracts signed before the 1980s. At that time there were no pipeline links between Algeria and Europe, and the pipeline network to import natural gas from the Former Soviet Union and the North Sea was less well developed than today. As a result the current mix of pipeline and LNG supplies does not necessarily represent the most economical mix of gas supply for European buyers. In general, Norwegian and other North Sea supplies and Russian gas represent the lowest cost sources for northern Europe, and Algerian pipeline gas is the lowest cost supply source for southern Europe. However, LNG continues to play an important role as a source of gas supply as shown by the continued willingness of European buyers to sign contracts for new LNG supplies from Nigeria, Trinidad, Norway (Snøhvit), and Middle Eastern suppliers. The reasons for the continuing role of LNG are:

- Buyers seek diversity of supply for security reasons. For example, the Spanish government has legislated for a 60% market share limitation on gas from a single source.
- Pipeline capacity is constrained, especially in supplying markets in southern Europe. For example, in Spain the existing Algerian export pipeline (the Maghreb-Europe line) is operating at full capacity, and significant investment is needed for a major expansion in pipeline gas supply. The 2 Bcm/year Lacal pipeline crossing the Franco-Spanish border is currently the only link between the Iberian peninsula and the rest of Europe and is also operating at full capacity. Constructing LNG reception facilities may be cheaper than additional pipeline capacity[1].
- With the current tariff structures, gas from the north is constrained from effective competition in southern Europe by high transit costs.
- As the markets liberalise, LNG often offers the opportunity for power producers and other large consumers to secure their own gas supplies and provides new sellers with early access to a supply source to support market entry.

Figure 19: European LNG import terminals



Source: Gas Strategies

1 However, there are also plans to build new pipelines linking Iberian markets to potential supplies, notably the Medgaz project which would link Algeria and Spain directly via an undersea pipeline, and a second string to the Lacal pipeline which links Lacq in France to Calahorra in Spain.

The US market

The USA is the world's largest natural gas market consuming 650 Bcm (equivalent to around 475 mt of LNG) in 2000. North American gas infrastructure is highly developed, and there are few gas pipes of significant capacity that are not connected to the continent-wide network. Natural gas is freely traded with prices being set by the balance of supply and demand.

Four LNG terminals were constructed on the East and Gulf Coasts in the 1970s and 1980s, initially to import LNG from Algeria at a time when shortages of indigenous gas were forecast. These deals collapsed in the early 1980s as a result of disputes over price, resulting in three of the four terminals being mothballed. All four terminals will be open again by the end of 2002, giving the US the capacity to import up to 20 mtpa of LNG (imports in 2001 were 4.8 mt). The LNG terminals are all linked into the natural gas infrastructure so regasified LNG can be delivered to any point in the system, either physically or by trading. Cargoes of LNG can always be sold into the US market, provided regasified LNG is priced at or below the prevailing market price. However, LNG supplied only around 1% of total US gas demand in 2001, and had no more than a marginal effect on prices. Nonetheless this figure of 1% of US gas demand represents a much larger market share for LNG in the US than has been the case for many years. Indeed, US LNG imports increased from 0.5 mt in 1996 to 4.8 mt in 2001 with all the world's LNG producers except Libya, Brunei and Alaska delivering cargoes of LNG to US terminals during that time. This increase in LNG imports can be attributed to three major factors:

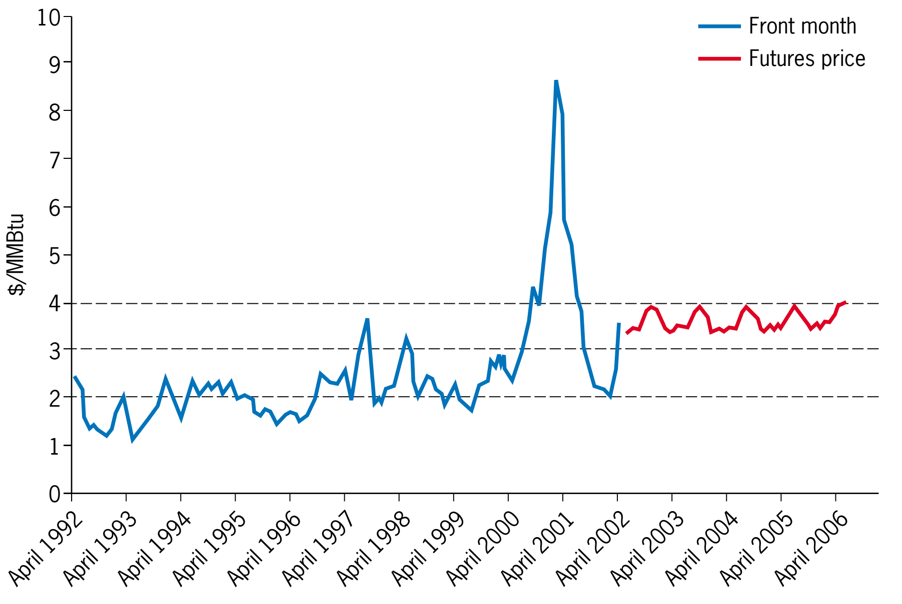
- The desire of LNG producers to offload surplus LNG cargoes following the economic downtown in Japan and Korea in the late 1990s;
- The very high gas prices seen in the US market in early 2001; and
- The commissioning of the Atlantic LNG plant in Trinidad in 1999, much closer to the US East Coast than other LNG plants.

These factors are considered in more detail below.

Surplus cargoes and spot sales

The US gas market, due to its highly liquid spot market, provides LNG suppliers with an opportunity to sell cargoes of LNG without a long-term contract – provided the supplier is prepared to accept a price based on a netback from US market prices. No other LNG market currently offers a similar opportunity, although spot cargoes have also been sold to Spain over recent years. In the late 1990s, suppliers in the Middle East, Australia and South-East Asia saw in the US an opportunity to market surplus cargoes of LNG, which were available because of the downturn in demand from their existing customers in Asia. The resulting sales had a significant impact in re-opening the US market to LNG.

Figure 20: Henry Hub natural gas prices

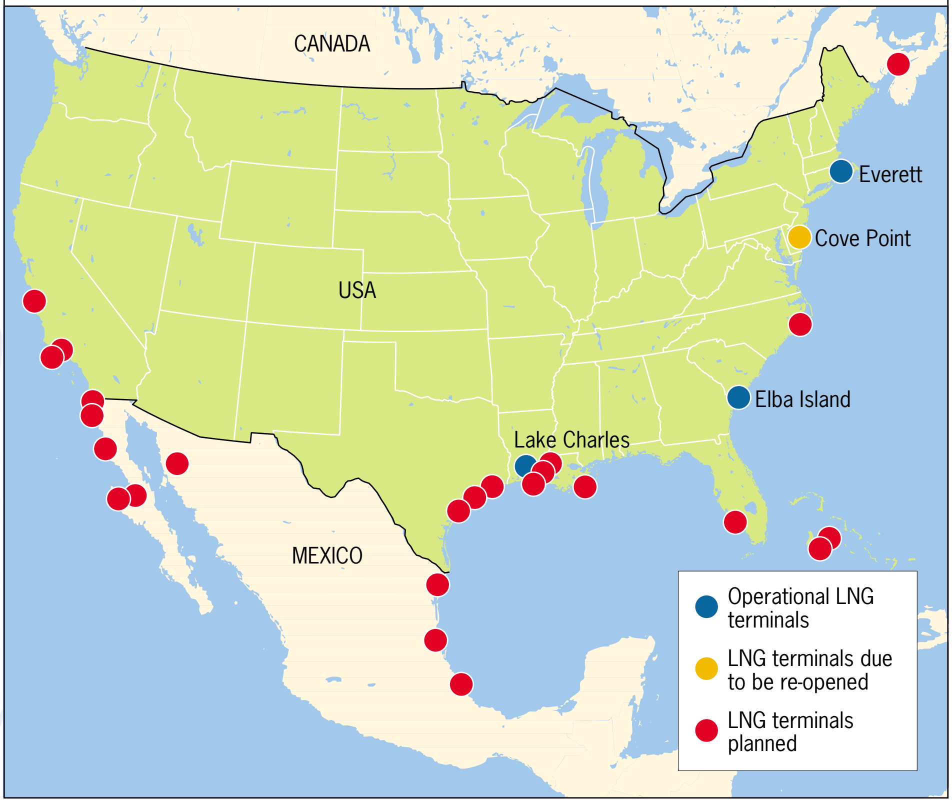


Settlement data as of 5th April 2002
Source: Nymex

US gas price rises

For much of the 1980s and early 1990s US gas prices at the Henry Hub (a pipeline interconnection in Louisiana that is the delivery point for the main US gas futures contract, and therefore the major US reference price marker) averaged around $2/MMBtu, a level that could not support LNG imports. However, prices increased dramatically in 2000 and 2001, peaking at nearly $10/MMBtu in early 2001. Prices at this level offered attractive netbacks to LNG producers, who responded by sending cargoes to the US. There was also at least one case of an LNG buyer diverting a cargo from its original destination in Europe and selling it to the US market. The sensitivity of US LNG imports to prices was illustrated by the decline in prices in the last quarter of 2001 to below $2.50/MMBtu. Only the closest suppliers, Trinidad and Algeria, have delivered cargoes of LNG since the price fell.

Figure 21: North American LNG terminals



Source: Gas Strategies

The commissioning of Atlantic LNG

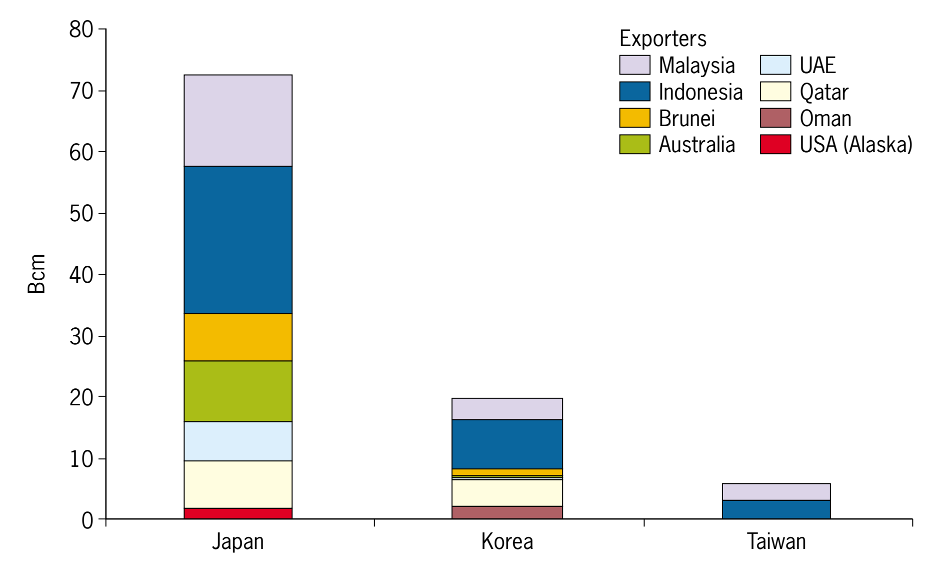
The development of the Atlantic LNG plant in Trinidad has also been an important factor in the growth in US LNG imports. When it came on stream in April 1999, it was the first new facility with a long-term contract to supply the US market (1.2 mtpa to be delivered to the Everett terminal in Massachusetts). Its location close to the US East Coast and its low gas production and liquefaction costs, means that it can continue to supply LNG profitably to the market even when Henry Hub prices are below $2.50/MMBtu.

Puerto Rico

The first LNG import terminal on the west side of the Atlantic and outside the US mainland began operations at Penuelas, in the south of Puerto Rico, in 2000. The terminal and integrated 507 MW power plant are owned by Eco-Electrica (a 50/50 joint venture between Enron and Mission Edison). The first cargo of LNG, which is mainly supplied from Trinidad under a contract with Tractebel LNG, was delivered in August 2000. In 2001, the terminal received 0.45 mt of LNG including one cargo from Oman. Plans to increase LNG imports to supply industrial markets and additional power plants in Puerto Rico are on hold pending resolution of terminal ownership following Enron's collapse.

Asia-Pacific

Figure 22: Asia-Pacific LNG imports, 2000



Source: BP Statistical Review of World Energy, 2001

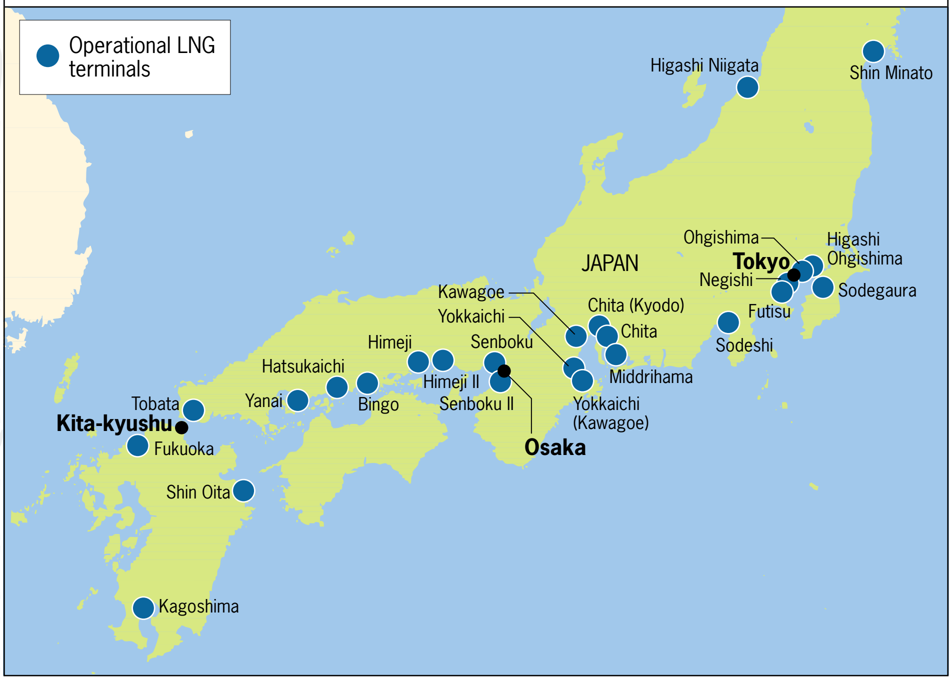
In contrast with the Atlantic basin region, where LNG has to compete with pipeline gas, LNG is the dominant source of natural gas supply in the Asia-Pacific markets of Japan, South Korea and Taiwan. Indigenous gas production in all three countries is limited and there are no pipeline imports so LNG meets over 95% of gas demand. The region as a whole accounts for 71% of world LNG demand and Japan alone imports over 50% of world production.

The main LNG demand in Japan is from power companies that account for nearly 70% of the imports. Most of the large power companies (Tokyo, Chubu, Kansai, Chugoku, Kyushu and Tohoku Electric) are LNG purchasers. The large gas companies in Tokyo, Osaka, and Nagoya have been LNG buyers since the early days of imports. Since the 1990s, a number of smaller gas companies have begun to take LNG in small tankers, or, in the case of Shizuoka Gas, in cargoes shared with Tokyo Gas. There are still many small gas companies throughout Japan supplying customers, mainly in the residential market, with manufactured gas.

There are currently 25 terminals in operation in Japan, all owned by the LNG importers (15 companies own a terminal or a share in a terminal). There is no national pipeline system connecting the terminals but there are individual networks around each of the LNG terminals and in the main consumption centres of Tokyo, Osaka and Nagoya. These distribution networks are gradually expanding and now reach most of the densely populated areas, giving approximately 65% of Japanese households access to natural gas. Further expansion of the pipeline network is constrained by the terrain and rights of way issues that make pipeline construction both expensive and time-consuming.

Japan buys LNG from all the LNG producers in the Asia-Pacific region and the Middle East. Indeed, until the development of Oman LNG and the RasGas project in Qatar, contracts with Japanese buyers underwrote all the LNG developments supplying Asian markets. Each of the main Japanese LNG buyers has diversified its LNG supply through contracts with two or more suppliers. Tokyo Electric, the world's largest LNG buyer with around 16 mt of imports in 2001, has long-term contracts with seven different suppliers.

Figure 23: Japanese LNG terminals



Source: Gas Strategies

Korea and Taiwan each have only one LNG importer, Korea Gas Corporation (Kogas) and the Chinese Petroleum Corporation (CPC) respectively. These companies supply regasified LNG to power companies (Kepco in Korea and Taipower in Taiwan) and to local distribution companies and industrial users.

The Korean Government is currently proposing to split Kogas into four companies to create competition in the market. Kogas would own and operate the LNG terminals and pipeline infrastructure and three new companies would be responsible for buying LNG and selling it to customers (one of these new companies would initially be controlled by Kogas). This proposal has faced opposition in Korea and the timing of its implementation is uncertain.

A second company, Pohang Iron and Steel Company (Posco), has plans to import LNG to Korea for its own use and for sale to third parties. In January 2002, Posco announced its intention to build a 1.7 mtpa regasification plant near its Kwangyang Works in the south of Korea. Construction is due to start in June 2002, and to be completed in 2005.

Kogas currently operates two terminals at Pyeongtaek and Inchon, near Seoul. It is also constructing a third terminal at Tongyeong in the south-east of the country, which is due to be commissioned at the end of 2002. Kogas' initial LNG supplies came from surplus capacity and new LNG trains in Indonesia and Malaysia but in the mid-1990s it signed long-term contracts with new Middle Eastern suppliers – Oman LNG and RasGas (Qatar). Korean LNG imports reached 15.8 mt in 2001. Kogas' policy is to import LNG on an FOB basis and it now has a fleet of 17 ships in operation and one on order.

Nearly 50% of Kogas' LNG imports are consumed in the domestic and commercial sector and as a result peak demand in winter is some three times higher than in the summer. Kogas manages the swing in demand through LNG storage (it will have over 3 million cubic metres of storage when the Tongyeong terminal is commissioned at the end of 2002) and the purchase of short-term cargoes in the winter.

Figure 24: Korean LNG terminals

Source: Gas Strategies

Taiwan has one LNG import terminal in the south of the island near Kaohsiung. An onshore pipeline connects the terminal to the largest consumption centre in the north around the capital, Taipei. A second, offshore, pipeline to the north has been built but is not yet in operation. About two thirds of Taiwan's gas demand is for power generation and this share could increase to over 70% as the Government implements a policy of giving preference to gas–fired plants.

Figure 25: Taiwanese LNG terminals

Source: Gas Strategies

The Taiwanese Government also supports the development of a second terminal in the north to create competition and increase the security of supply. A contract to supply 1.8 mtpa of LNG to a new 4 GW power plant, planned by Taipower at Tatan (near Taipei), is critical to the viability of a northern terminal. Two attempts to award the contract through competitive tendering have failed through lack of bids (three valid tenders are required under Taiwanese law but only two were received on each occasion). As a result, the prospects and timing of a new terminal remain uncertain.

Market outlook

Europe

There are three LNG terminals under construction in Europe (including Turkey) at Bilbao in Spain, Sines in Portugal, and Aliaga in Turkey.

Table 13: European LNG terminals under construction

Terminal	*Country*	*Capacity (mtpa)*	*Start*	*Owner*	*Main Supplier*
Bilbao	Spain	2.0	2003	BP, Repsol, Iberdrola, EVE	Atlantic LNG
Aliaga	Turkey	4.4	2002	Ege-Gaz	Not determined, permits not complete
Sines	Portugal	1.8	2003	Transgas, GdP	Nigeria LNG

Source: Gas Strategies

Plans have been announced for further terminal developments in Spain, France, Italy and the UK. The most advanced plans are for Union Fenosa and Iberdrola's terminal at Sagunto near Valencia in Spain that will be developed initially to receive LNG from Union Fenosa's liquefaction plant at Damietta in Egypt, which is currently under construction. The Rovigo terminal in Italy is also well advanced. It will be a gravity-based structure located about 12 km offshore in the northern Adriatic and will be built to receive cargoes under Edison's 3.5 mtpa contract with RasGas in Qatar.

The El Ferrol terminal in north-west Spain has Sonatrach as one of its partners and appears to be linked with Algeria's plans to increase its natural gas exports to Europe. BG's planned terminal in Brindisi in southern Italy is facing strong local opposition and may be cancelled. Finally, there are two projects in France, one at Verdon on the Atlantic coast, which is part of TotalFinaElf's plan to create a gas hub based around its Lacq gas field and associated infrastructure in south-west France, and the second a new terminal at Fos sur Mer on the Mediterranean that would allow Gaz de France to import LNG on large ships (the existing terminal at Fos can only receive vessels of less than 75,000 m^3 capacity).

UK utility group, Lattice, has also proposed the construction of a new terminal at the Isle of Grain in south-east England, to improve supply security as the UK is forecast to become a net gas importer over the next decade. The UK last received LNG in the late 1980s through a terminal at Canvey Island that has now been dismantled.

Table 14: Planned European LNG Terminals					
Terminal	*Country*	*Capacity (mtpa)*	*Start*	*Owner*	*Main Supplier*
Sagunto	Spain	3.6	2004/5	Union Fenosa, Iberdrola	Egypt
El Ferrol	Spain	?	2004/5	Endesa, Union Fenosa, Sonatrach, & others	Algeria?
Rovigo	Italy	3.0	2004/5	ExxonMobil, Edison	RasGas
Brindisi	Italy	3.0	2005	BG	Egypt (BG/Edison)
Verdon	France	2.3	2005	TotalFina Elf	Not yet determined
Isle of Grain	UK	0.3 – 1.0	?	Lattice	Not yet determined
Fos sur Mer	France	?	?	Gaz de France	Egypt?

Source: Gas Strategies

Americas

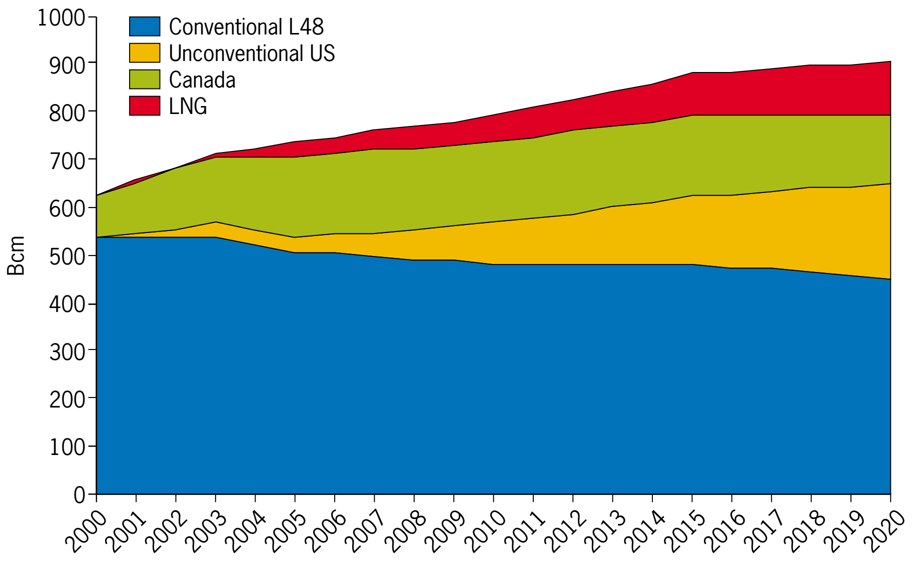
USA

The US is likely to remain the main market for LNG on the western side of the Atlantic basin but the outlook for LNG demand is uncertain. The existing four terminals can import around 20 mtpa and all have expansion plans that will increase their combined capacity to 30 mtpa. High gas prices in 2000 and early 2001 and the expectation of firm prices in the medium to long-term were major factors in the announcement of around 20 proposals for new LNG imports facilities in 2001. These included a number of terminals to be located outside the US in Mexico, Canada and the Bahamas (see figure 21) whose principal role will be to import LNG for the US market. One area of major activity in this regard is Baja California in north-western Mexico, where a number of companies are looking to develop terminals to supply regasified LNG to California. The supply for these terminals would come from new LNG facilities in South America or from facilities in Asia and Australia seeking alternatives to Asian markets, where demand is currently growing more slowly than the potential supply. In total these new terminals could add a further 30 to 50 mtpa of capacity, however, since US gas prices have receded from their 2001 peak, it is unclear how many, if any, of these projects will go ahead.

The demand for LNG in the US will also depend to a large extent on the availability of gas from other sources to meet growing US demand. The Energy Information Administration (EIA) of the US Department of Energy forecasts that US gas consumption will increase by 60% over the next 20 years (figure 26). The largest growth is forecast in the power sector, due to an increase in the construction of combined-cycle gas power plants (some 90% of planned power capacity is gas-fired). At the same time, the EIA predicts a decline in gas from conventional sources in the lower 48 states (the USA excluding Alaska and Hawaii). Supply will increasingly have to come from an increase in non-conventional domestic sources, such as coalbed methane, Canadian imports, and LNG, all of which may only be economically viable if US gas prices are above $3/MMBtu. Future US gas prices are uncertain, but with the gas supply/demand match tightening over the next decade, current forecasts place US prices in the $3 to $4/MMBtu range in the medium to long-term. The Nymex futures market in April 2002 supported that expectation, as is shown in figure 20.

The eventual level of imports directly into the US will depend on the level of prices, price competitivity with alternative markets in Europe and elsewhere in the Americas and the number of liquefaction facilities built to supply Atlantic basin markets.

Figure 26: US gas supply forecast



Source: Energy Information Administration

Mexico

Mexico is expected to become a net importer of gas during the next decade and a number of potential sites are being considered for the development of LNG terminals to import LNG for the Mexican market. One demand centre that has been identified is at Altamira on the east coast. The existing Pemex pipeline in the region is at the extremity of supply going north and a substantial power generation corridor exists to the west of Altamira where some 10-15 GW of power generation could be developed. Shell is involved in a joint venture with El Paso to develop an LNG terminal in the Altamira area. A second possible location for an LNG terminal to supply the Mexican market is at Cardenas on the west coast.

Caribbean and Central America

AES is constructing a terminal at Andres, near Santa Domingo, in the Dominican Republic. It is scheduled to be commissioned in mid-2002. AES has signed an sales and purchase agreement (SPA) with BP for 12 cargoes of LNG (about 0.7 mtpa). The SPA does not specify the source of the LNG and is the first contract not to do so. There are plans for similar projects in Honduras and other locations in the Caribbean and Central America.

Brazil

Most of Brazil's electricity demand (over 90%) is currently met by hydro-electricity but demand growth in excess of 5%/year is putting pressure on the system, particularly in the north-east. The Brazilian Government has therefore decided to embark on a program of developing gas-fired power generation. Shell and Petrobras plan to build an LNG receiving terminal and linked 500 MW power plant at Suape in Pernambuco State, north-east Brazil. An import licence and environmental licence for construction have been issued, meetings have taken place with potential suppliers and a shortlist has been drawn up. The project is scheduled to start in mid-2005. There are also plans for an LNG import terminal and power plant further north at Fortaleza in Ceara State.

Asia-Pacific

Existing markets

The prospects for growth of LNG demand in the largest market, Japan, are poor. The economy has been in recession for many years, with few signs of growth being re-established, so the prospects for increased natural gas and power demand are lower than in the past. This is especially the case in the power sector where gas use grew rapidly in the 1970s and 1980s as its share of fuel supply increased to around 25%, a level of dependence that most utilities do not want to see increase.

Moves by the Japanese Government to deregulate natural gas and power markets are causing further uncertainty for the utilities. Utilities are concerned at the potential loss of market share in supply areas where they previously enjoyed a monopoly position. The uncertainty in the overall level of demand and in the share of the market they will retain makes the utilities reluctant to commit to new supplies of LNG. Where they are in a position to consider new supplies, they are likely to want increased volume flexibility (i.e. lower take or pay obligations) and shorter-term contracts.

Demand in Korea continues to grow rapidly and the country needs to commit to new LNG supplies. However, the Government's policy of breaking-up Kogas means that there is no company currently in a position to commit to new long-term supplies. CPC in Taiwan has found itself in an oversupply position as a result of lower than expected power demand and delays in the development of new IPPs. It is unlikely to be in a position to commit to new LNG supplies for several years. Furthermore, plans for a terminal in the north, which would create new LNG demand, have also been delayed.

Overall, none of the buyers in Japan, Korea and Taiwan are currently in a position to enter into the large-scale and long-term contracts that underpinned the development of all the operating liquefaction plants in south-east Asia, Australia and the Middle East. As a result, projects seeking to develop new production, either through the expansion of existing plants or through greenfield developments, are increasingly looking to new markets in Asia.

China

The two largest potential new markets in Asia are China and India. In China, an LNG terminal is being developed by a consortium, in which BP has 30% and Chinese companies (including CNOOC) 70%, at Shenzhen, in Guangdong province, south-east China. The project will initially supply gas for power generation in Guangdong and to customers in Shenzhen, Dongguan, Guangzhou and Foshan. The second phase of the project includes extending the trunkline and supplying gas to further cities in the Pearl River Delta. In January 2002, CNOOC announced a shortlist of three bidders, Australia LNG, BP (Tangguh) and RasGas, to supply 3 mtpa to the terminal for 25 years. LNG will be purchased on an FOB basis and the Chinese Government has invited bids from shipping companies and shipbuilders to provide LNG transport services.

India

In India, natural gas consumption has risen faster than any other fuel in recent years, and the Indian Government has been encouraging the construction of gas-fired power plants. The potential for domestic gas production is limited and pipeline imports face major political and logistical challenges so LNG is well placed to meet rising demand. 12 possible LNG import schemes have been approved by India's Foreign Investment Promotion Board, although it was never considered likely that all would be built.

The project that has made most progress is at Dabhol in Maharashtra State, where Enron took the lead in developing a 2.1 GW power plant and LNG import facility. The first phase of the power plant started-up in 1999 using naphtha as the fuel source but disputes over price with the buyer of the power, the Maharashtra State Electricity Board (MSEB), led to the plant being shut down and work on the nearly completed LNG terminal being suspended. Enron's collapse has further complicated the situation. The plant is now for sale with a number of international and Indian companies expressing an interest.

The only other terminal under construction is at Dahej in Gujurat State where Petronet, a consortium of Indian and foreign interests, is constructing a 5 mtpa facility. It has a contract to purchase 7.5 mtpa of LNG from RasGas, partly for Dahej and partly for a second terminal planned at Cochin in the south-west.

The other terminals are at various stages in the planning process but the problems at Dabhol have increased the uncertainty for all the prospective developers. Some projects seem to have been abandoned (for example, TotalFinaElf's project at Trombay near Mumbai) and others appear to be on hold (BG's project at Pipavav and the project at Ennore in Tamil Nadu state). However, others such as Shell's Hazira project, Reliance's Jamnagar project and the Kakinada project are still being progressed.

The Philippines

Another potential Asian market is the Philippines where LNG is under consideration for power generation. In November 2001, Pertamina announced that it had signed a Memorandum of Understanding to supply 1.3 mtpa to an IPP near Manila.

Chapter 6: Marketing

LNG Sales and Purchase Agreements (SPAs) were developed from pipeline gas contracts and share many features in common. However, the complex nature of LNG supply chains has led to the development of specific marketing and contractual arrangements for LNG, as distinct from the normal contract forms for pipeline gas. This chapter examines LNG marketing and contracts and in particular the use of LNG Sales and Purchase Agreements.

The history of LNG contracts

LNG Sales and Purchase Agreements (SPAs) were developed from pipeline gas contracts in the early days of the LNG industry. At that time, both sellers and buyers needed long-term commitments to provide security to raise finance, often running into several billion dollars, for their respective facilities. Alternative sources of LNG were unlikely to be available to buyers if supplies were disrupted and there were few alternative markets available to sellers if the long-term buyers were unable to receive the LNG. As a result, the terms and conditions in LNG SPAs include severe penalties for a failure to perform including, for example, obligations for the buyer to pay for an agreed volume of LNG even if it is unable to take all the volume (take-or-pay).

As the LNG business continues to expand, the needs of buyers and sellers are changing and this is beginning to be reflected in the terms and conditions of SPAs agreed in recent years. However, much of the trade is still being carried out under long-term agreements with substantial penalties for a party that fails to meet its contractual obligations.

The development of the SPA

One of the main challenges for developers of new LNG production capacity is to secure markets for the planned output. As expenditure on the project increases sponsors will generally want to be sure that the buyers will commit to take the LNG. Similarly, as buyers progress their plans to receive the LNG and develop markets for its consumption, they will want assurance that the LNG supplies will be available. As a result, buyers and sellers often adopt the approach of a series of agreements that increase the level of commitment between the parties and define the main terms and conditions under which the trade will be carried out. These agreements will usually lead to the SPA, which fully commits the parties to the supply and purchase of the LNG and is the basis for both sides to make the major investment in facilities to produce, transport, receive and consume the LNG. An example of the sequence of agreements is as follows:

- **Letter of Indication or Letter of Interest (LOI)** – typically a letter from the buyers to the project sponsors indicating their interest in the project. At this stage neither side will have made an irrevocable commitment to invest in the project.

- **Memorandum of Understanding (MOU)** – an agreement signed by both sides outlining the plans for the project and indicating the intention to negotiate, in good faith, an SPA.
- **Letter of Intent (LOI), Heads of Agreement (HOA), Confirmation of Intent (COI)** – an agreement setting most of the main terms for the supply and purchase of LNG. At this stage the buyers and sellers would normally make a commitment to enter into a full SPA provided specified conditions precedent are met and certain approvals are received.
- **Sales and Purchase Agreement (SPA)** – this sets out the full terms and conditions for the supply and receipt of the LNG. With its signature, both sides are committed to invest in the development of their part of the project chain.

Projects may decide some of the above stages are not required. They may, for example, opt to negotiate an SPA without entering into all the intermediate agreements. There is even one example of a project going no further than an HOA, and successfully delivering LNG on that basis for many years. Overall, buyers and sellers will adopt the approach that is appropriate for their own particular requirements and those of the project as a whole.

Contractual arrangements

The key terms in a typical LNG SPA include:

- The length of term of supply
- The amount to be delivered annually (Annual Contract Quantity (ACQ)) and flexibility to increase or decrease volumes
- Price
- Responsibility for marine transportation
- Scheduling procedures
- The heating value and main components of the LNG
- Measurement and testing
- Force majeure
- Destination

Each of these contractual conditions is considered in more detail below.

Term of supply

Most LNG contracts have an initial supply term of 20 years. A number of the early contracts have now reached the end of their initial term but in most cases they have been extended for a further term. A 20-year term is generally needed by both buyers and sellers to provide the long-term security to underpin investment in their respective facilities. Recent developments have seen divergent trends. Some buyers are seeking shorter-term contracts because of increased uncertainty in the long-term outlook in their markets. On the other hand, some buyers are still looking for the long-term security provided by a 20-year contract, and in a few cases the contract duration has been extended to 25 or even 30 years.

Annual Contract Quantity (ACQ)

The volume of LNG the buyer agrees to take and the seller agrees to supply is referred to as the Annual Contract Quantity (ACQ). The SPA will specify the ACQ during the build-up phase and when the project is at full production (the plateau). The build-up period can extend from a few months to as long as 5 or 6 years and is usually a critical issue for both parties. The sellers will want to maximise early cash flows by having the build-up determined by the production capacity of the LNG plant. This is normally a period of only a few months at most since, once an LNG train is commissioned, full production capacity can be achieved quickly. The buyers will often want a slower build-up to allow them to develop their markets. As a result, the rate of build-up is often a compromise between the different needs of the parties to the SPA. The plateau volumes are usually the same each year and are generally fairly evenly spaced over the year, although there may be some small seasonal variations to take into account the needs of the buyer. As far as possible, plant overhauls and the dry-docking of the ships will be arranged at times of low demand for the buyer.

The SPA normally gives the buyer a limited scope to reduce volumes during each year – referred to as Downward Quantity Tolerance (DQT). This has typically been less than 10% of the ACQ. In addition, the buyer usually has the option to increase volumes by a small amount (a few cargoes) each year if the seller has the capacity to supply additional LNG. The ACQ minus the DQT sets the volume of LNG that the buyer has to pay for whether or not it is taken – the so-called take-or-pay (TOP) level. The buyer will only be released from its take-or-pay obligation to the extent that the failure to take is for reasons of force majeure (see below) or the seller has been unable to supply the LNG. The amount of DQT allowed and hence the take-or-pay obligation is a major issue for LNG buyers who will generally want to maximise the downward volume flexibility, while sellers will want to maximise the 'guaranteed' revenues, which is likely to be a critical factor in the financing of the investment. The level of take-or-pay in older contracts is usually over 95% but in more recent contracts this has been reduced as buyers have sought to increase the flexibility of off-take. Sellers have been reluctant to reduce the level too far but the growth of the overall LNG market and the increase of spot and short-term trading means that there are now likely to be alternative outlets for at least some of the LNG not taken by the long-term buyer. If a buyer has incurred TOP payments by lifting less than the adjusted ACQ, it acquires a right to make up the quantity of gas it has paid for but not taken. This may be free of charge, or the buyer may be required to pay the difference between the price when the TOP was paid and the price when the make up volume is delivered. Both systems are commonly used. There is sometimes a time limit on when make up has to be lifted, for example within five years, but in many contracts, the make up volumes can be taken any time in the contract life, and the contract may also be extended if there are make up volumes outstanding at the end of its life.

Price

A key issue for both the seller and the buyer is the price of the LNG. The parties will usually agree a base price for the LNG and a formula determining how the price will be escalated over the life of the contract. However, it is also possible that the SPA will describe the principles for the determination of the price in the SPA and the parties agree that the price itself will be agreed closer to the start-up of deliveries. Provision for the renegotiation of the price at regular intervals, or in the event that it moves out of line with the market, may also be included in the SPA.

Responsibility for marine transportation

A critical issue for buyers and sellers is whether the sales should be on an FOB (free on board) basis, with the buyers being responsible for transportation, or an ex-ship basis, with the sellers providing the shipping. Ex-ship sales, which are essentially the same as CIF (cost, insurance, freight) sales, formerly dominated the LNG business, especially in Asia, but there is currently a trend for buyers to prefer FOB purchases. For example, 86% of contracts signed by Asian buyers before 1995 were on a delivered (ex-ship or CIF) basis, but since 1995 85% have been on an FOB basis.

One reason for preferring FOB sales has been the buyer's desire to promote its national shipbuilding and ship operating industry, but today many buyers want the flexibility of owning their own ships to allow them to trade LNG and to improve the management of their LNG supply. From an LNG seller's point of view, FOB sales avoid having to finance the ships, but also mean that there is no shipping capacity available to trade LNG if surplus volumes are available. For this reason, the Oman project, whose long-term contracts are all on an FOB basis, recently took control of one ship and has ordered a second to allow it to sell spot LNG on a delivered basis.

Whether the terms of trade are FOB or ex-ship, the SPA has to ensure that sufficient shipping capacity is committed for the ACQ to be delivered. It also has to ensure the compatibility of the ships with the loading and/or unloading terminals.

Scheduling procedures

Both the sellers and the buyers will want to ensure optimum use of their facilities. The scheduling of the ships will be a critical factor in achieving this objective. The SPA normally defines the procedures for developing the Annual Delivery Programme (ADP) for the project. As the name suggests, this is agreed annually and provides for the number of cargoes to be delivered, the ships on which they are to be transported, and the dates of loading and unloading.

MARKETING

Heating value and main components of the LNG

The SPA sets a range for the heating value of the LNG and its main components (hydrocarbons such as methane, ethane, propane etc., and impurities such as carbon dioxide and solid particles). The SPA will define the rights of the buyer to reject the cargo and the penalties to be paid by the seller if the LNG is outside these ranges.

The heating value of the LNG is becoming an increasingly important factor as the trading of LNG between regions increases. Buyers in Asia generally prefer LNG with a relatively high calorific value, whereas buyers in the Atlantic basin need LNG with a lower calorific value to meet the needs of their customers.

Measurement and testing

The volume of LNG loaded onto the ship (for an FOB sale) or discharged from the ship (for an ex-ship sale) is measured by gauges on the ship's tanks. The quality, including the heat content, is determined by shore-based equipment at the loading or unloading terminal. Using the two measurements, the energy (normally measured in Btus) received by the buyer is determined for the purpose of invoicing. In addition to defining the measurement and testing procedures, the SPA will provide for the rights of each party to challenge the results if they are considered to be inaccurate.

Force majeure

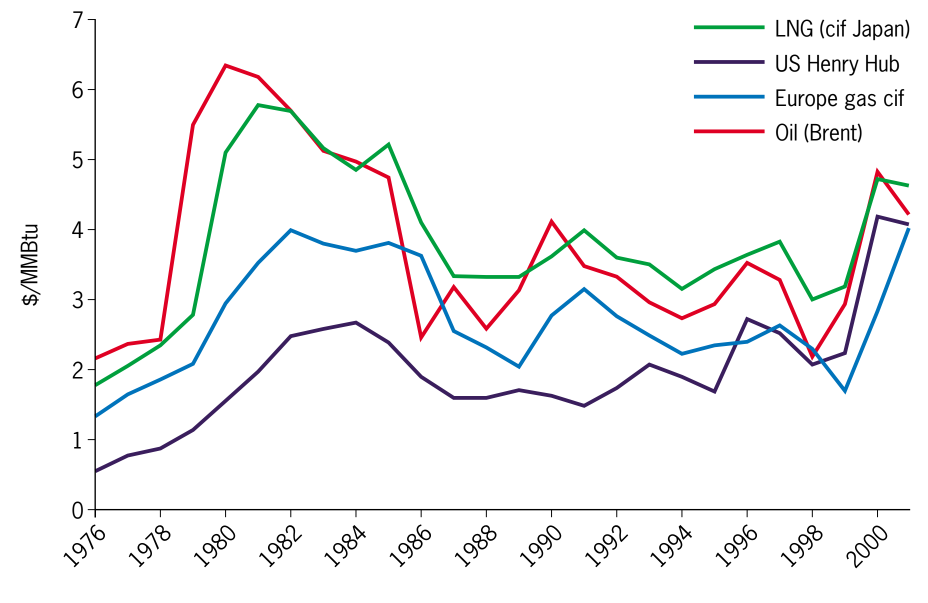
Force majeure is defined as 'any circumstance that is beyond the reasonable control of the party affected which prevents or hinders due performance of obligations under the contract and which cannot be overcome by due diligence'. The type of events that are normally accepted as constituting force majeure include acts of war, actions of governments, damage to facilities not caused by negligence, and the failure of a third party to perform under a contract. The party affected by the force majeure will normally be relieved of all its obligations under the agreement, except the payment of outstanding invoices. The unaffected party will usually be allowed to trade with third parties while the force majeure is in effect and, in the event of a prolonged force majeure, to terminate the contract.

Destination flexibility

Most existing LNG contracts provide little or no flexibility for the LNG to be delivered to a destination other than the buyer's own receiving terminal or terminals, even in cases where the sale is on an FOB basis and the buyer controls the ships. Destination restrictions are increasingly unacceptable to buyers who want the flexibility to sell cargoes to alternative markets to help manage variations in their own market demand and to take advantage of price arbitrage opportunities, especially in the Atlantic basin.

Pricing

Figure 27: Natural gas and crude oil prices, 1976–2001



Source: BP Statistical Review of World Energy 2001

As figure 27 shows, there have been major differences over the last 25 years between natural gas prices in the three regional markets that import LNG. In general, Asia-Pacific prices (represented by Japanese LNG prices in figure 27) have been the highest, followed by prices in western Europe, with US prices the lowest. The prices shown for Europe and the USA in the figure are for natural gas rather than LNG but, since LNG has to compete with pipeline gas in these markets, they are representative of the realised prices for LNG. In the case of Asia, Korean and Taiwanese import contracts use similar price formulae to those used by Japanese imports so the average price of LNG imported by Japan is representative of prices in Asia-Pacific LNG markets. This section considers the different pricing formulae used in each region.

Asia-Pacific

In the early agreements with Japanese LNG buyers, prices were fixed in nominal terms for the 15 or 20-year life of the contract. However, they were at a significant premium over the low price of crude oil in the late 1960s and early 1970s. The premium helped to support the development of the early LNG projects in Alaska and Brunei. Following the first oil price shock in 1973, when oil prices suddenly rose from around \$3/bbl to more than \$12/bbl, buyers and sellers agreed to a new pricing approach that linked the price of LNG directly to crude oil prices. This lasted until oil prices collapsed in the mid-1980s. A new round of negotiations at that time resulted in a pricing regime that has lasted into the twenty-first century. This regime has also been adopted by the most recent LNG importers, Korea and Taiwan.

The use of crude oil as a price escalator has been maintained but the linkage has been weakened so that, on average, a 10% rise in crude oil prices results in a rise of about 7% to 8% in the LNG price. All Asian LNG price formulae can be reduced to:

$$P_{LNG} = A \times P_{Crude\ Oil} + B$$

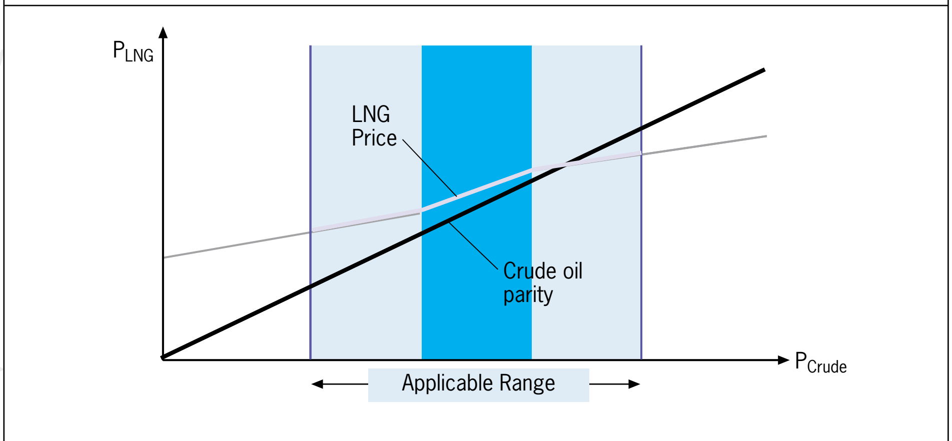
Where:

P_{LNG}	is the price of LNG in US cents/MMBtu
$P_{Crude\ Oil}$	is the price of crude oil expressed in US dollars per barrel
A	is a constant (typically around 14.85)
B	is a fixed amount, varying from contract to contract

Most contracts use the Japanese Crude Cocktail (JCC) as the crude oil price although the price for Indonesian LNG is linked to the average price of Indonesian crude oil. JCC is used in Korean and Taiwanese prices and was also adopted for sales to the Dabhol project in India. The constant B in the above formula is typically between 70 cents and 90 cents/MMBtu in ex-ship contracts. The level of the constant has usually been the main issue in recent price negotiations between LNG buyers and sellers.

The effect of this formula is to give LNG a premium of between 10% and 15% over crude oil parity (on a Btu basis) when oil prices are around \$18 to \$20/bbl. At lower oil prices the premium increases and at higher prices it decreases and eventually disappears at oil prices around \$30/bbl (depending on the value of 'B' in the formula). A more recent development in most of the contracts with Japanese buyers has been the introduction of the so-called 'S' curve, where there is an additional premium over crude oil for the LNG sellers at low oil prices (below around \$16/bbl). This is compensated by a larger discount at high oil prices (above about \$24/bbl). 'S' curves are not yet used for Taiwanese or Korean LNG.

Figure 28: 'S' curve price formula

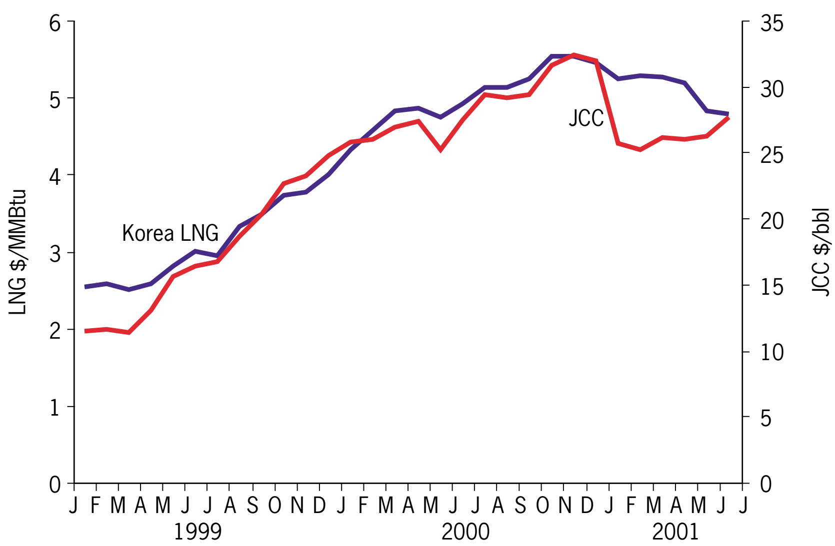


Source: Flower Consulting

In most of the agreements, LNG prices are linked to oil prices with a lag of up to 3 months. In addition, it generally takes a few weeks for changes in spot oil prices to be reflected in JCC prices. Therefore, on average, it takes several months for a change in oil prices to be fully reflected in Asia-Pacific LNG prices.

The following graph shows the average price of LNG imported into Korea and JCC from January 1999 to June 2001.

Figure 29: Korean LNG and Japanese crude cocktail prices

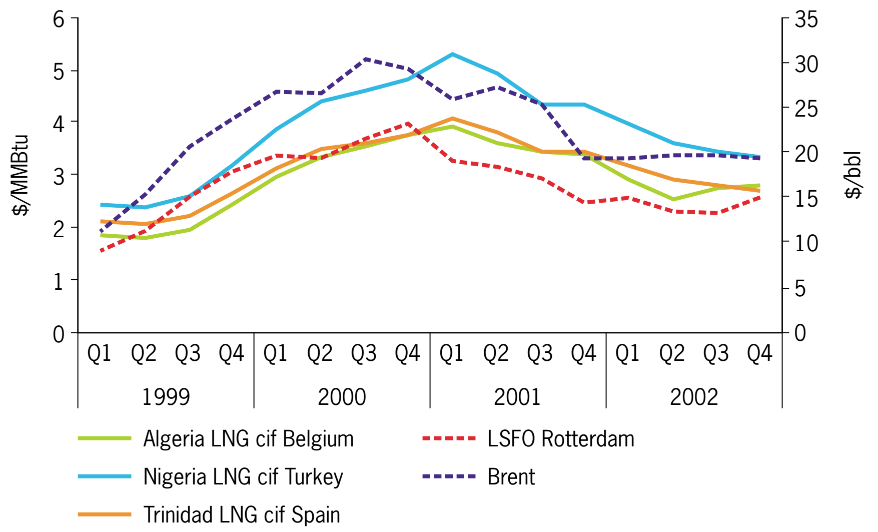


Source: Korea Energy Economics Institute; Petroleum Association of Japan

Europe

Natural gas prices in long-term contracts in Europe are commonly indexed to oil product prices (generally gasoil and fuel oil) with a lag of up to six months. In some cases, other commodities such as coal, electricity and a general inflation index are included in the escalation formula. Since LNG has to compete with pipeline gas, a linkage with oil product prices has been adopted for all the LNG currently imported into Europe. However, as markets are being liberalised, the approach to pricing is changing and at least one LNG contract has adopted a new approach of linking the price with electricity prices. In general, LNG prices are comparable with pipeline gas prices on a delivered basis, which, after adding regasification costs, makes them higher by approximately $0.30/MMBtu. The graph below shows examples of LNG, crude oil, and low-sulphur fuel oil (LSFO) prices.

Figure 30: European LNG, crude oil and LSFO prices



Q3 and Q4 2002 refer to forward prices
Source: GasStrategiesOnline

MARKETING

USA

In the US, natural gas is freely traded between buyers and sellers and prices are set by the balance of supply and demand. The price at the Henry Hub is used as the reference point for natural gas prices across the USA. The price at the point of delivery varies depending on local supply and demand conditions and transmission costs. The following table shows the minimum and maximum differential to the Henry Hub for pricing points near the four existing US LNG terminals during the period 1998-2001.

Table 15: Differential to Henry Hub

	Minimum differential	Maxmium differential
Lake Charles	–11 cents	+2 cents
Elba Island	+2 cents	+6 cents
Cove Point	+15 cents	+80 cents
Everett	+11 cents	+83 cents

Source: BSA

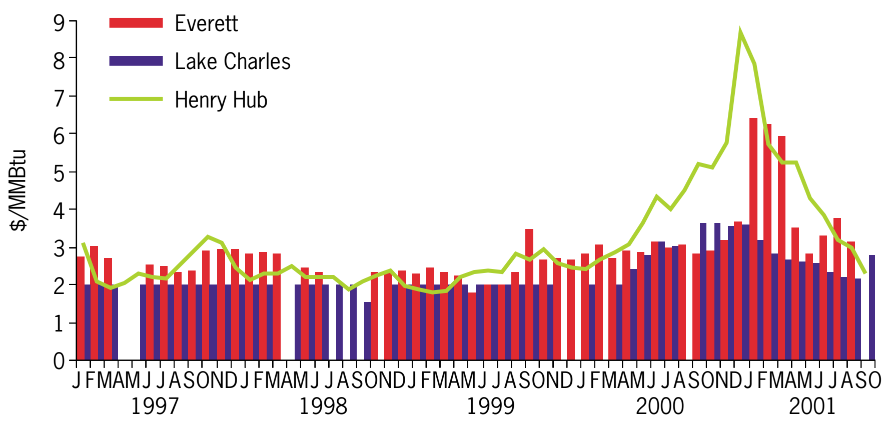
Since regasified LNG has to compete with pipeline gas in the US, Henry Hub prices provide the basis for the pricing of cargoes delivered to the US. Typically, the price of LNG can be netted back to the loading point as follows:

> Delivered price (ex-ship) at US terminal = Henry Hub +/– the locational premium/discount – the terminal cost (fee + fuel use and loss)

FOB price at the liquefaction plant = delivered price – shipping cost (ship charter, fuel use, cost of boil-off gas, port charges)

LNG sellers can use the futures market to fix prices forward and manage the risk of US prices falling while the ship is in transit. The following figure compares realised LNG prices and Henry Hub prices over the period 1997 to 2001.

Figure 31: Realised US LNG prices and Henry Hub prices, 1997–2001



Source: The Natural Gas and Petroleum Import and Export Office, Nymex

Chapter 7: Shipping

Shipping forms the essential link between LNG production facilities and the markets. At the beginning of 2002 there were 128 LNG ships in operation worldwide. Most of these ships were committed to projects on a long-term basis and only six were employed for short-term trading. The order book for new ships was at a record level, with nearly 60 ships due to be delivered between 2002 and 2006. This chapter describes the existing LNG fleet and analyses expected additions to it, as well providing details of LNG ship prices and shipping costs.

The existing fleet

Most of the ships in operation at the beginning of 2002 had a capacity of over 120,000 m^3 but there were also a number of smaller ships (table 16).

Table 16: LNG ships in operation, January 2002

Capacity	Number of Ships
18,000 m^3 to 50,000 m^3	16
50,000 m^3 to 120,000 m^3	15
> 120,000 m^3	97
Total	**128**

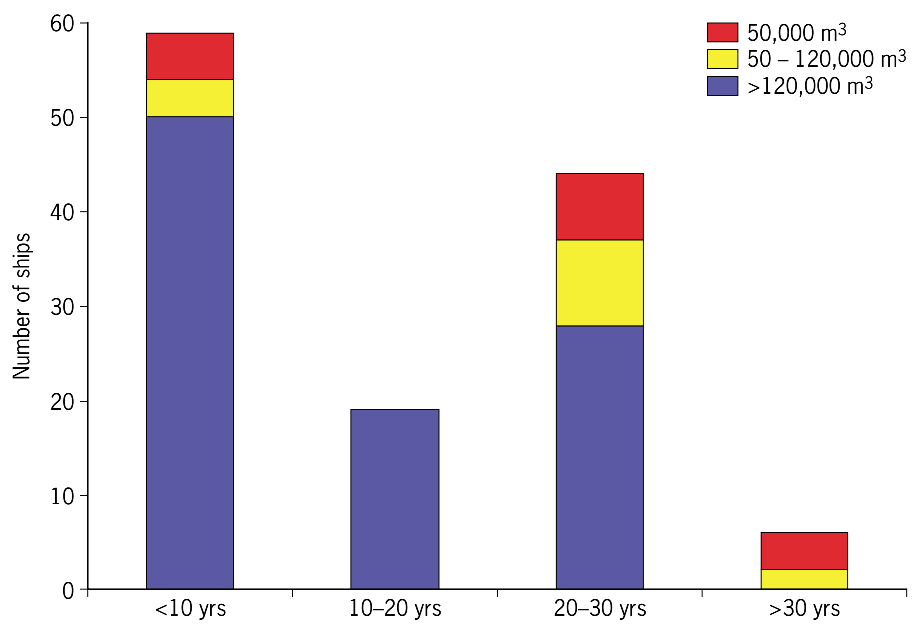
SHIPPING

Five of the ships in the 18,000 m^3 to 50,000 m^3 category are used to transport LNG from Malaysia and Indonesia to medium-sized gas companies in Japan. These ships were brought into service in the 1990s. All the other ships in this category were built in the 1960s and 1970s to transport LNG from North Africa to southern Europe and continue to supply terminals in Spain, France and Italy that cannot receive large ships. The medium-sized (50,000 m^3 to 120,000 m^3) ships were also mainly built in the 1960s and 1970s.

In the early days it was expected that LNG ships would have a twenty-year life. However, they have generally been maintained to a very high standard and the life of the typical ship is now considered to be well in excess of twenty years. Indeed, the oldest ship currently in operation is 37 years old.

As a result, the age profile of the fleet has a significant tail of ships that have been in operation for over 20 years and a number that are over 30 years old (figure 32). Many of the older ships operate in the Atlantic basin. The Asia-Pacific fleet is more modern, reflecting the fact that most of the new liquefaction capacity commissioned since 1980 supplies buyers in Japan, Korea and Taiwan.

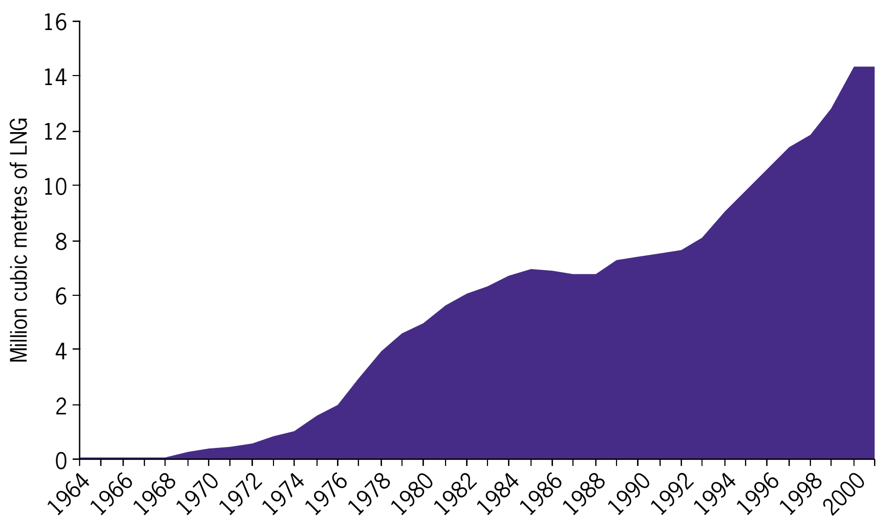
Figure 32: Age profile of the world LNG fleet as at April 2002



Source: Various

Figure 33 shows how the total capacity of the world LNG fleet has built up since the first ships came into service in 1962. By the end of 2001, the capacity of the fleet was over 14 million cubic metres of LNG.

Figure 33: LNG fleet cargo tank volume, 1964–2001



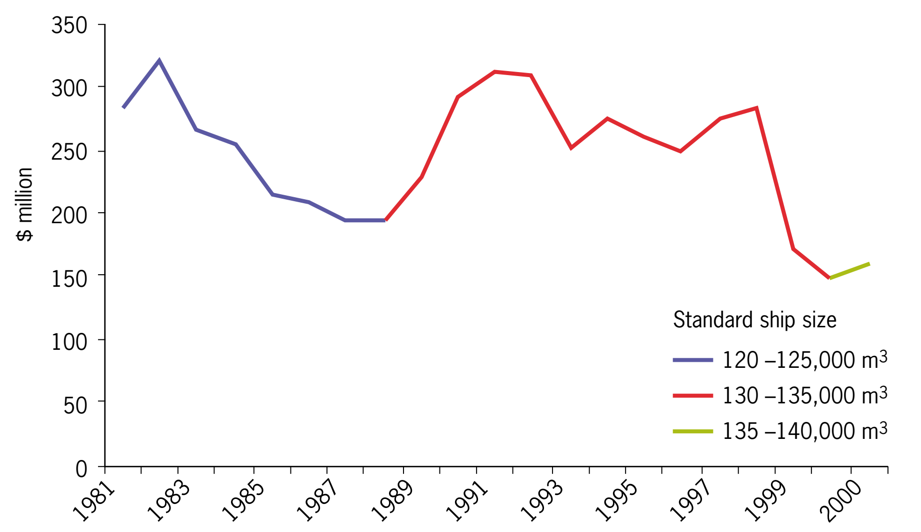
Source: Marine Service

LNG ship prices

The prices of LNG ships have shown considerable variation over the last 20 years. A critical factor is the demand for new ships and, since LNG ships are constructed in the same berths in the yards as Very Large Crude Carriers (VLCCs), the demand for these ships can have a major impact on the price. Figure 34 shows the evolution of the price of a 'standard' LNG ship since 1981. 'Standard' in this context refers to the capacity of the majority of ships being ordered. The standard size has increased from 120,000 m^3 to 125,000 m^3 in the 1980s to 135,000 m^3 to 140,000 m^3 by 2001.

The price of a 'standard' ship in nominal dollars, which was around \$150 million throughout most of the 1980s, increased to between \$200 million to \$250 million in the 1990s. It fell back to \$150 million in 2000 but has risen again and in early 2002 stood at about \$170 million. If these prices are adjusted for inflation, then in nominal, 2001 dollars, ship prices fell during the 1980s from over \$300 million to around \$200 million, increasing sharply to \$270 million to \$310 million during the 1990s, before falling to about \$150 million in 2000.

Figure 34: The development of LNG ship prices, 1981–2001



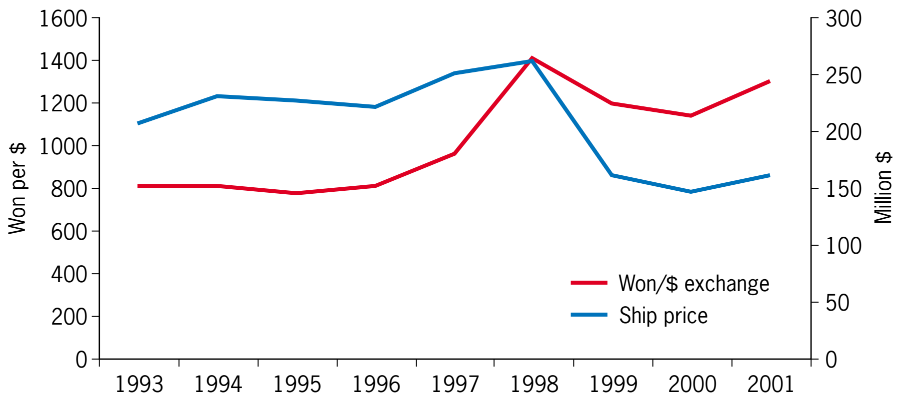
Prices calculated in nominal \$2001

Source: Marine Service

There are a number of reasons for the fall in the price of LNG carriers in the last few years. The increased competition amongst shipyards has probably been the most important factor. Japanese yards built most of the LNG ships in the 1980s and early 1990s. Since then shipyards in France, Finland, Italy and Korea have all built LNG ships. The Korean yards have proved to be particularly competitive. Having completed 17 ships for Kogas between 1994 and 2000, they bid aggressively to build ships for non-Korean companies. Aided by the fall in the value of the Korean

Won against the US Dollar (figure 35), they were able to offer very competitive prices and were successful in securing contracts for over 60% of the ships on order in early 2002.

Figure 35: Price of ships produced in East Asian shipyards and Korean Won/US Dollar exchange rate, 1993–2001

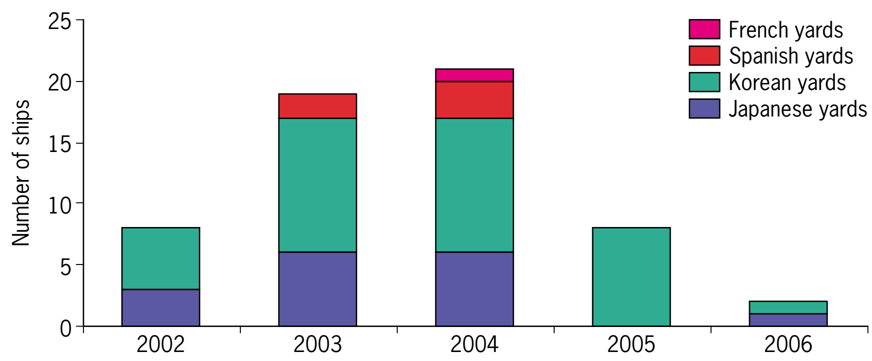


Source: Gas Strategies

New ships

Between 2000 and 2002 a record number of new LNG ships were ordered. Figure 36 shows the year of delivery of the ships on order and where they will be built. The total number of ships currently on order is 58 and the peak year is 2004 when 21 ships are scheduled to be delivered. The previous peak year for LNG ship deliveries was 2000 when 10 were brought into service.

Figure 36: LNG ships on order in April 2002



Source: Various

All but one of the ships on order has a capacity of over 135,000 m^3 and a number of the more recent orders have been for ships of 145,000 m^3 capacity. The only smaller ship was a 74,000 m^3 vessel for Gaz de France being built at the Chantiers d'Atlantique yard in France. The total cargo capacity of the ships on order was around 8 million cubic metres, so the overall fleet size will be increased by nearly 60% when all the new ships are in operation.

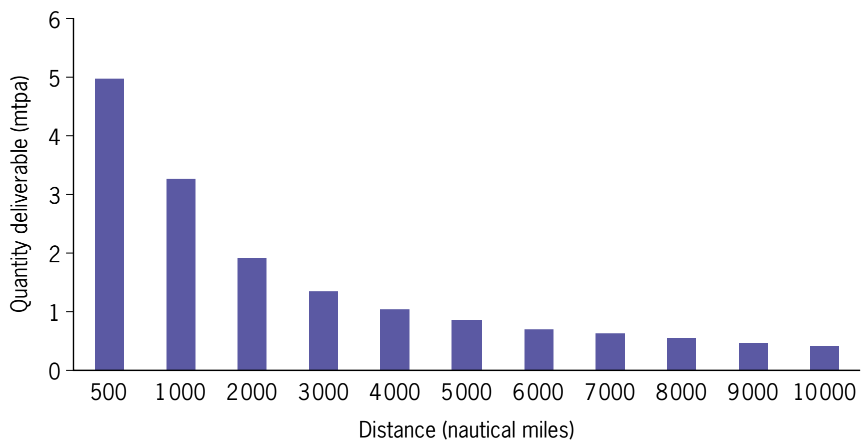
A feature of the order book is that it contains a number of orders by ship-owners who have not as yet secured employment for the vessels. This is the first time so-called speculative orders have been placed for over 20 years. At that time, most of the speculators lost out with their ships being laid-up for a number of years because of the lack of employment. The order book also includes, for the first time, ships ordered by oil and gas companies that plan to use them for their own trading purposes rather than as part of a project in which they are participating. In all, around 40% of the ships on order in early 2002 do not appear to be linked to a particular liquefaction project in operation or under construction. As these ships are delivered into service over the next few years, a surplus of uncommitted ships may develop, allowing the expansion of the spot and short-term trading of LNG.

LNG projects account for just under 40% of the ships on order compared with 60% of the ships in operation. This is indicative of the trend towards FOB rather than ex-ship sales in new sales contracts. Buyers will control 35% of the ships on order, similar to their share of the existing fleet. Ship owners and oil and gas companies account for the remaining 25% of the ships on order.

Shipping costs

The cost of transporting LNG is very much a function of the distance between the liquefaction plant and the receiving terminal and hence the number of ships required for a particular trade. Figure 37 illustrates the volume of LNG a 135,000 m^3 ship can transport each year as a function of the distance.

Figure 37: Approximate quantity deliverable by one 135,000m^3 ship



Source: Gas Strategies

The costs of operating a ship are made up of two main components: fixed costs, including capital charges, crew costs and insurance, and variable voyage costs including fuel, boil-off gas and port charges. Overall, fixed costs comprise around two-thirds of the total transportation costs, with variable costs representing the remainder. However, the division of costs varies, depending, for example, on the rate of return the ship owner requires on its investment in the ship and the cost of fuel oil and boil–off gas.

The transportation cost per MMBtu of LNG delivered varies considerably with distance. Table 17 shows some illustrative costs based on a new 138,000 m^3 ship costing $170 million with the owner earning around 10% on his investment. The average speed is assumed to be 18.5 knots and one day is allowed for loading and one day to unload the ship.

Table 17: Illustrative LNG shipping costs

Distance nautical miles	*Round voyage time (in Days)*	*Cost in $/MMBtu*
1800	11	0.35
3750	19	0.60
6200	30	1.00

Source: Gas Strategies

Chapter 8: Short-term trading

Long-term contracts have underpinned the development of the LNG business across the world. They have provided both sellers and buyers with the confidence to commit to the billions of dollars of investment needed in gas production, liquefaction, shipping, receiving terminals and downstream distribution and consumption facilities. Without the long-term commitment by the sellers to supply the LNG and by the buyers to receive the cargoes, the LNG business could not have developed to the extent it has today.

However, long-term contacts have created rigidity in the LNG business that does not necessarily satisfy the needs of the buyers and sellers in the twenty-first century. Buyers are facing increasing uncertainty regarding the level of demand, and their own market share in their traditional markets, and sellers risk losing important incremental revenues if all their sales are committed to buyers in a single market or region. As a result the short-term trading of LNG has been increasing through the 1990s and into the twenty-first century. Despite the growth in short-term trading, LNG remains a predominantly long-term business, with less than 6% of production in 2000 being traded on a short-term basis. This chapter examines the development of and outlook for short-term LNG trading.

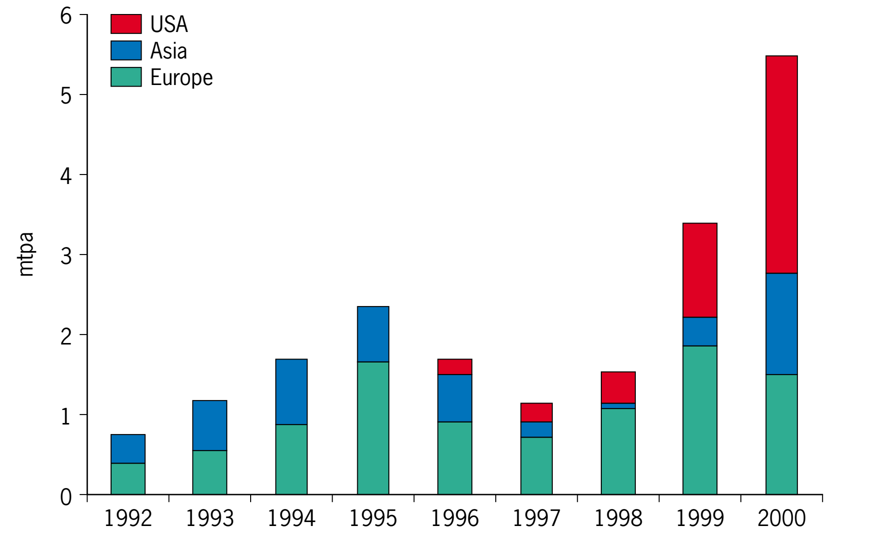
The development of short-term trading

Before the 1990s, short-term LNG consisted mainly of additional cargoes of LNG traded between buyers and sellers where there was already a long-term contract. These short-term cargoes were available because LNG plants were able to produce well above their design capacity. LNG buyers needed extra supply to meet demand, which in certain cases had grown faster than had been expected at the time when the LNG contracts were initially signed. At this time there were only a few cargoes traded between buyers and sellers that did not have a long-term relationship and even less were traded between regional markets. Five cargoes sold by Sonatrach to Japanese buyers in the late 1980s was one of the few exceptions.

In the early 1990s, European LNG buyers were faced with a shortage of supply because production from the dominant producer in the region, Sonatrach, was reduced as it refurbished its liquefaction plants. The buyers turned to producers in the Middle East and Australia to make up the shortfall in supplies, boosting short-term LNG trading (figure 38). Short-term LNG peaked at 3.5% of the total LNG production in 1995 but declined over the next two years as the Algerian LNG trains were re-commissioned.

In 1996, the USA began to emerge as a market for short-term cargoes of LNG. The operation of the Lake Charles terminal in Louisiana on an open access basis, gave LNG producers the opportunity to sell LNG cargoes on a short-term basis, provided they were prepared to accept a price based on a net-back from US spot market prices. The downturn in the Asian economies in the late-1990s meant that many of the producers in the Asia-Pacific region and in the Middle East had surplus cargoes of LNG that their long-term buyers could not take. Increasingly, they looked to the US as a market for such cargoes. The rise in US gas prices in 2000 and the early part of 2001 made the US an increasingly attractive market for LNG sellers.

Figure 38: LNG short term trades by market, 1992–2000



Source: Various

US short-term imports increased rapidly, reaching 2.7 mt in 2000 and 3 mt in 2001, representing around 50% of world LNG short-term trades.

Asia-Pacific has also re-emerged as a market for short-term trades, mainly as a result of Kogas needing to import additional volumes of LNG in the winter months to manage increased consumption in the residential and commercial sectors. In addition, buyers in the Asia-Pacific region have begun to exchange cargoes to help meet unexpected changes in demand. Europe has remained a significant importer of short-term LNG, as existing buyers use LNG to meet variations in demand, and new players use LNG to enter liberalising markets.

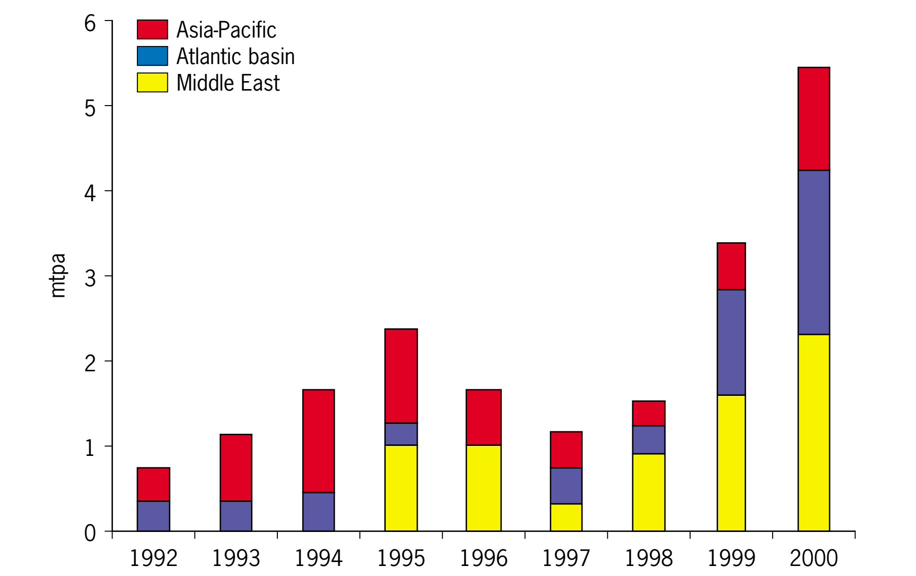
Short-term LNG sellers

The Middle East has emerged as the main supplier of short-term cargoes. In the mid-1990s most spot cargoes came from the liquefaction plant on Das Island in Abu Dhabi and were sold to Europe. Qatar has been playing an increasing role since the start-up of its Qatargas facility in 1997 and its RasGas plant in 1999. Indeed, the first cargo produced by RasGas was a short-term cargo delivered to the US. Oman LNG has also become an important supplier of short-term LNG following its start-up in 2000. In that year, 42% of short-term cargoes were produced from Middle Eastern LNG plants.

Atlantic basin producers accounted for just over one-third of the short-term cargoes in 2000. This share has increased as a result of the start-up of the Atlantic LNG and Nigeria LNG plants in 1999. The transfer of cargoes from Europe to the US when US prices are high and transfers in the opposite direction when US prices are low now represents a large part of the short-term trading of LNG in the Atlantic basin.

LNG projects in the Asia-Pacific region have marketed some LNG cargoes on a short-term basis throughout the period 1992 to 2000. Initially, the cargoes were mainly supplied to existing long-term buyers. However, an increasing number of cargoes are being delivered to Atlantic basin markets. Furthermore, buyers in the Asia-Pacific region are increasingly exchanging cargoes between themselves to manage changes in demand.

Figure 39: LNG short term trades by source of supply, 1992–2000



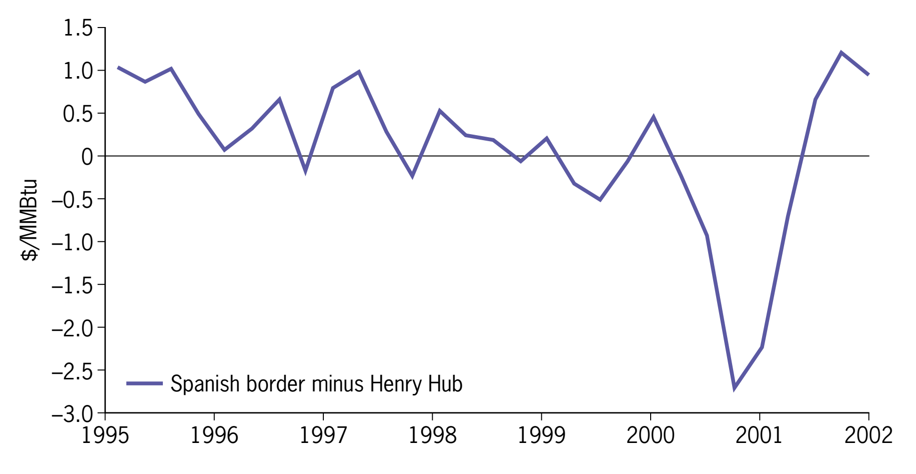
Source: Various

The pricing of short-term cargoes

Short-term sales of LNG can be made on the basis of a single cargo or a number of cargoes over a limited period of time. Whatever the nature of the arrangements, prices are invariably set according to the market into which they are sold. The price will either be fixed when the cargo is loaded or it may be linked to an escalator (for example, Japanese crude oil prices in Asia or oil products in Europe). In the case of the US, the price will be netted back from Henry Hub prices but it can be fixed at the time of loading or the time the sale is agreed using the futures market.

The Atlantic basin provides the LNG seller or trader with two reasonably proximate markets (the US and Europe) where natural gas prices are set in very different ways. This allows cargoes to be arbitraged between the two markets to take advantage of price differences that, as figure 40 shows, can be significant.

Figure 40: Henry Hub and Spanish border average price differential, 1995–2002



Positive number indicates Spanish price higher, negative number indicates Henry Hub higher
Source: GasStrategiesOnline; NYMEX

The 15-month period from January 2001 to April 2002 demonstrated the extent to which LNG volumes are beginning to be switched between markets on either side of the Atlantic in response to price differences. In the first nine months of 2001, Henry Hub prices were at a significant premium over European prices and US short-term imports averaged 320,000 tonnes per month. During that period only one cargo from Atlantic LNG in Trinidad, which has contracts to supply 40% of the LNG from its first train to Spain and 60% to the USA, was delivered to Spain, as buyers chose to divert LNG and sell it into the US market.

US prices fell in the last quarter of 2001 and remained below European prices until April 2002. During the final quarter of 2001, US short-term imports fell to an average of 40,000 tonnes per month. In addition, the supply of LNG cargoes from Trinidad to Spain resumed.

In the Asia-Pacific markets, LNG prices are at a similar level in Japan, Korea and Taiwan so price has not played a role in short-term trading between markets. The needs of buyers to balance supply and demand has been the main factor behind the short-term trading that has taken place.

The outlook for short-term trading

The main factors needed for the expansion of the short-term trading of LNG are:

- Surplus supply
- Market demand and receiving terminal capacity
- Uncommitted ships
- Flexible contracts

The main constraints on short-term trading at the beginning of the twenty-first century are the shortage of uncommitted ships and the lack of flexibility in contracts. The latter factor restricts the ability of buyers to transfer cargoes to alternative markets, to take advantage of higher prices, or to manage over-supply situations.

It is expected that both of these constraints will be relaxed over the next few years. A record number of LNG ships were ordered from shipyards in 2000 and 2001. Many of these ships are not committed to a specific project and should be available for short-term trading. These ships will be brought into service starting in the second half of 2002.

Buyers are increasingly using their strong negotiating position to relax the restrictions on their freedom to trade LNG cargoes or to transfer them to alternative markets. Many of the contracts for new LNG supplies announced in 2001 and 2002 included provisions that increased the flexibility of LNG supply. In this process, destination clauses, which specify the market and even the terminal to which the LNG can be delivered, are coming under increasing pressure.

In early 2002 world LNG production capacity was already significantly higher than contracted volumes. In addition, there was around 40 mtpa of new capacity under construction. Receiving terminal capacity, especially in the Atlantic basin, also exceeded the amount of LNG under contract and a number of new terminals were under construction or being planned. Therefore, the facilities to import increased volumes of short-term LNG were in place or being built.

Overall, all the factors required for short-term LNG trading to expand will be in place in the medium-term, so an increase from the 2001 level of just under 6% of total trade can be expected over the medium to long-term. However, buyers and sellers still face high capital investment costs to develop facilities to produce, transport, regasify and consume natural gas. They will generally want to see a major part of their output or their LNG production committed on a long-term basis to underpin their investments. This will limit the growth of short-term LNG trading. Consequently, it is unlikely that short-term trading will dominate the LNG business in the way that it does in the oil industry, rather short-term markets are likely to grow slowly within the context of the existing long-term contract framework.

Chapter 9: The outlook for LNG

The LNG business has grown consistently over its 37-year history. Total world trade reached just over 104 mt in 2001. The outlook for the future is encouraging, with more liquefaction trains, LNG ships and receiving terminals under construction or being planned than at any time in the past. Some forecasts show the annual trade doubling by 2010 and possibly trebling by 2015. If the more optimistic projections are to be realised, then acceleration in the pace of change experienced in recent years will be needed.

Because buyers' markets now generally prevail in LNG, the rigidities which have characterised the business are being relaxed. Furthermore, LNG costs have been progressively reduced so that it can be competitive in more markets and more situations than were imaginable a decade ago. Scenarios for future gas supply and demand in major European and North American markets suggest that supply gaps will increasingly be met from more distant sources, including LNG.

One of the main changes in the last few years has been the re-emergence of the Atlantic basin region as a growth market for LNG. Although the international trading of LNG started in the Atlantic basin, Asia-Pacific took over as the main growth area for LNG and by the mid-1990s it accounted for over 75% of world trade, with Japan alone importing over 60% of world LNG production. Increasing short-term imports into European and US markets and the commissioning of LNG plants in Trinidad and in Nigeria has transformed the Atlantic basin market. In the 5-year period from 1996 to 2001, US LNG imports grew (from a small base) tenfold and total Atlantic basin trade by an average of 12% per annum. In contrast, LNG trade in the Asia-Pacific region grew by 5% per annum.

The dynamics of the regional LNG markets are very different. In the Asia-Pacific markets of Japan, Korea and Taiwan, supplies of pipeline gas are currently limited and LNG is competing with other fuels (coal, oil and nuclear). Energy demand growth in these markets has slowed considerably and the unpredictable consequences of liberalisation of energy markets have made it hard for the traditional LNG importers to assess their future needs. In a climate of uncertainty, it is more difficult for buyers to make commitments to new long-term LNG imports. Slow progress in traditional Asia-Pacific markets gives added importance to the new markets of China and India. However, signing up supplies to these markets has proved more difficult and time-consuming than expected, though the long-term demands for LNG could be substantial. Overall, therefore, LNG growth rates in Asia are likely to remain slower than in the past, with the mature markets remaining sluggish and the new markets struggling through their birth pangs.

The many expansions and green-field projects being planned in the Middle East, South-East Asia, Australia and Russia are in fierce competition to meet any new market opportunity that emerges. There is also growing interest in establishing import terminals on the west coast of North America since it could provide suppliers in the Asia-Pacific region with access to the US market without the long voyage to the east coast.

In Europe and the USA, LNG is competing with pipeline gas. It currently supplies only a small proportion of total natural gas demand (1% in the USA and 7% in Europe) so the opportunity for growth is substantial, providing LNG can be supplied on competitive terms. Most observers see the US market as a very good prospect for LNG as long as it is priced relative to the market. Suppliers have to take the price risk, but not the volume risk. Long-term pricing of gas in the US is a matter of some conjecture, but a level of somewhere around \$3.00 to \$3.50/MMBtu (with LNG supply having only a marginal effect on prices) is currently a widely accepted view. This would provide an open door for much Atlantic basin LNG. These circumstances underlie plans which have already been announced to expand the four existing US receiving terminals and to build new facilities.

On the other side of the Atlantic, LNG's main role has been in southern European markets that are remote from the main pipelines from the Former Soviet Union and from the North Sea. In these markets, LNG creates diversity of supply, avoiding over-reliance on pipelines from North Africa. Prices in Europe are still largely negotiated between buyer and seller but, as markets liberalise, trading hubs are being created and prices will increasingly be set by gas on gas competition as in the USA and the UK.

The reduction in the development costs for liquefaction plants and LNG ships has encouraged plans for a major expansion of LNG production capacity in the Atlantic basin. The extent to which these plans will be brought to fruition depends on the development of natural gas prices in the USA and Europe, as well as the extent to which project sponsors are prepared to take long-term price risk. However, producers do have the advantage of access to markets on both sides of the Atlantic basin to ameliorate the price risk and provide opportunities to take advantage of arbitrage opportunities created by price movements in Europe and the USA.

The old model of inflexible contracts suited buyers and sellers when supply security was a major concern. They are likely to play a diminishing role in the future as buyers seek more flexible terms to manage market uncertainty, including the right to trade cargoes between themselves. New supplies are already being contracted under conditions of flexibility which are much more appropriate to buyers' needs. Lower costs and intense competition to secure sales contracts have meant that sellers have been prepared to meet the buyers' requirements.

Sellers are learning to deal with new 'end-user' buyers that are very different from the major power and gas utilities that import most of the LNG currently under contract. In new markets the buyer will often be an independent power project or a relatively small local gas company that cannot offer the same security or size of market that the first generation of utility buyers provided. They may also be located in countries where end-pricing of energy is socially rather than economically determined, or where currency convertibility is not a given for the long-term. Innovative arrangements will be needed to ensure that sales to this type of buyer do not suffer the same fate as the Dabhol project in India.

The supplier with the lowest cost supplies will be best placed to meet the new realities of the market hence the cost challenge will continue for the developers of gas production, liquefaction plants, LNG ships and receiving terminals. Technical advances will be part of the response with floating liquefaction plants and floating receiving terminals likely to be the next major developments.

The spot and short-term trading of LNG has grown rapidly in the last five years and the expansion will continue, especially in the Atlantic basin where it increases the flexibility of both buyers and sellers to manage market uncertainties. However, it is likely that the majority of LNG production will continue to be traded under the terms of a long-term contract since this will suit buyers and sellers that need, respectively, the security implicit in guaranteed supply and offtake for at least a sufficient proportion of their needs or capacity. Nonetheless, as LNG trading becomes well established and LNG plants and terminals grow in numbers, the business will become more liquid. This will make it easier for new projects to go ahead with only part of their output committed to long-term buyers. Despite these developments the days of a truly merchant LNG plant, without a long-term sales contract, are probably a long way in the future.

Forecasts of the future of LNG seem dangerous due to the often counter-intuitive development of the industry in the past. However, the future is likely to owe much to three emergent trends.

- The changes in downstream markets and the emergence of new markets that are forcing buyers to seek much more flexible supplies than in the past.
- Reductions in the costs of LNG to the point where it is already competitive with pipeline gas in a number of growing markets.
- The development of short-term LNG trading and the flexibility this gives for LNG players to improve returns on investment and exploit and further develop niche market opportunities.

LNG will continue to offer exciting opportunities for new and old players. Entry fees may still be high, but they are declining, making entry possible for more companies into one of the few growth areas in the mature hydrocarbon business. A doubling of world LNG trade by 2010 may prove to be over-optimistic, but it is a realistic expectation by 2015. Whatever the outcome, there will be great business opportunities for those with the ambition, imagination, and innovation to realise the promise – and avoid the pitfalls – of LNG today.

Glossary

GLOSSARY

\$/te/yr	US Dollars per tonne of capacity per year – measure of LNG plant capital costs
ACQ	Annual contract quantity
ADGAS	Abu Dhabi Gas Liquefaction Company
ADNOC	Abu Dhabi National Oil Company
ADP	Annual delivery program
ALNG	Atlantic LNG Company of Trinidad and Tobago
APCI	Air Products and Chemicals, Incorporated
Associated gas	Gas found mixed with oil
Bbl	Barrel
Bcf	Billion cubic feet
Bcm	Billion cubic metres
Bcm/year	Billion cubic metres per year
BGT	Bonny Gas Transport
Btu	British thermal unit – one Btu is the amount of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 degrees Fahrenheit to 59.5 degrees Fahrenheit under a pressure of 30 inches of mercury at 32 degrees Fahrenheit. 1,000 Btu is approximately equivalent to one cubic foot of natural gas
CIF	Cost, insurance, freight
CNOOC	China National Offshore Oil Company
CoI	Confirmation of Intent
Condensate	Hydrocarbon liquid formed by precipitation from natural gas. Condensates consist primarily of pentanes (C_5H_{12}) and heavier components, and there will be some propane and butane dissolved in the mixture
CPC	Chinese Petroleum Corporation [Taiwan]
DoE	[US] Department of Energy
Dry gas	Natural gas containing little or no condensate
DQT	Downward quantity tolerance

EGPC	Egyptian General Petroleum Company
EIA	Energy Information Administration – Department of US Department of Energy
EPNL	Elf Petroleum Nigeria Limited
FERC	Federal Energy Regulatory Commission – the US energy regulator
FLNG	Floating LNG – floating liquefaction plant developed by Shell, so far not used in any LNG project
FOB	Free on board
GAIL	Gas Authority of India, Limited
GdF	Gaz de France
GdP	Gas de Portugal
GTL	Gas to liquids – a process which converts natural gas into liquid fuel
GW	Gigawatt – one billion Watts
HOA	Heads of Agreement
Henry Hub	Pipeline interchange near Erath, Louisiana, USA. The standard delivery point for NYMEX natural gas futures contract, and the benchmark natural gas price for the US
IHI	Ishikawajima Harima Industries
IOC	Indian Oil Company
IPP	Independent power project
JV	Joint venture
Kepco	Korea Electric Power Company
Kogas	Korea Gas Corporation
LOI	Letter of Indication/Letter of Interest or Letter of Intent
mcm	Million cubic metres – 1 mcm of LNG is equal to 600 mcm of natural gas at standard temperature and pressure
MCR	Multi-component refrigeration
METI	[Japanese] Ministry of Economics, Trade and Industry – formerly MITI
MISC	Malaysian International Shipping Company

GLOSSARY

MITI	[Japanese] Ministry of International Trade and Industry – former name of METI
MLNG	Malaysia LNG
MMBtu	Million British thermal units
MMcf	Million cubic feet
MOU	Memorandum of Understanding
MSEB	Maharashtra State Electricity Board
mt	Million tonnes
mtpa	Million tonnes per annum
Mtoe	Million tonnes oil equivalent
MW	Megawatt – one million Watts
NAOC	Nigerian Agip Oil Company
NGC	National Gas Company of Trinidad & Tobago
NGLs	Natural gas liquids – liquid hydrocarbons such as propane, butane, ethane, pentane and natural gasoline extracted from natural gas by absorption, adsorption, or refrigeration
NIOC	National Iranian Oil Company
NLNG	Nigeria LNG Limited
NNPC	Nigerian National Petroleum Company
NOC	National Oil Company [Libya]
NWS	North West Shelf [Australia]
OIEC	Oil Industries Engineering and Construction Company
ONGC	Oil and Natural Gas Company [Iran]
Peak-shaving plant	Facility storing gas for use at peak times
POC	Phillips optimised cascade
Posco	Pohang Iron and Steel Company
PSC	Production sharing contract
QGPC	Qatar General Petroleum Company – former name of QP
QP	Qatar Petroleum
R-PUF	Reinforced polyurethane foam
Scf	Standard cubic foot

SEIC	Sakhalin Energy Investment Company, Limited
Sonatrach	Algerian state oil and gas production and sales company
Sour gas	Natural gas containing a significant amount of hydrogen sulphide, and possibly other sulphur compounds, which must be removed before transport as they will cause corrosion to pipelines and equipment
SPA	Sales and Purchase Agreement
SPDC	Shell Petroleum Development Company
Sweet gas	Natural gas containing only small amounts of or no hydrogen sulphide and other sulphur compounds
Tbtu	Trillion British thermal units
TOP	Take-or-pay
TPA	Third party access
Unassociated gas	Gas found not mixed with oil
VLCC	Very large crude carrier - oil tanker with capacity over 100,000 deadweight tons (dwt)
Wet gas	Natural gas containing condensable hydrocarbons or other liquids. Natural gasoline, butane, pentane, and other light hydrocarbons can be removed by chilling, and may be sold

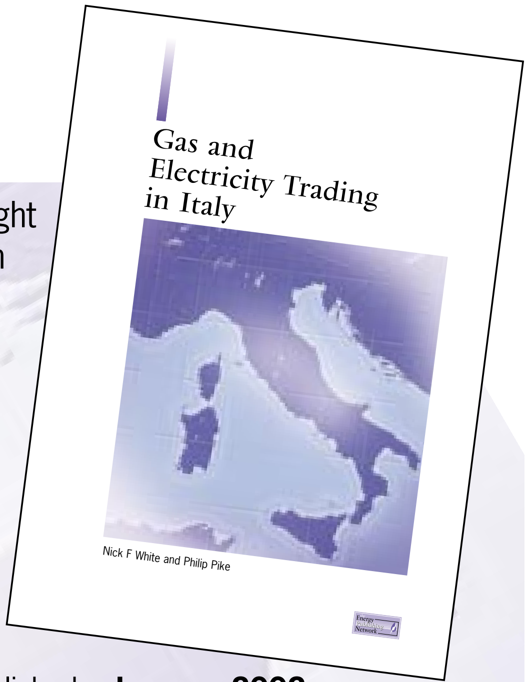
Conversions

	Bcm (gas)	*Bcf*	*Mtoe*	*TBtu*	*mt LNG*
Bcm (gas)	1	35.3	0.9	36	0.73
Bcf	0.0283	1	0.0255	1.0198	0.0207
Mtoe	1.1111	39.222	1	40	0.8111
Tbtu	0.0278	0.9806	0.025	1	0.0203
mt LNG	1.3699	48.356	1.2329	49.15	1

Source: BP

GLOSSARY

Gas and Electricity Trading in Italy



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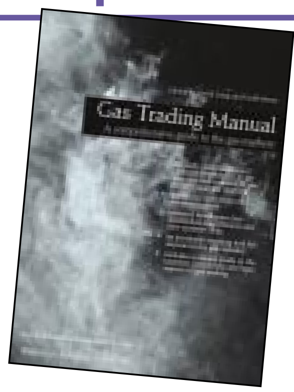

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