THE ASIA PACIFIC LNG MARKET
issues and outlook

ABARE RESEARCH REPORT 04.1

Prepared for the Australian Government Department of Industry, Tourism and Resources

Allison Ball
Karen Schneider
Lindsay Fairhead
Christopher Short

abare

ISSN 1037 8286
ISBN 1 920925 25 2

Ball, A., Schneider, K., Fairhead, L. and Short, C. 2004, *The Asia Pacific LNG Market: Issues and Outlook*, ABARE Research Report 04.1, Canberra, November.

Australian Bureau of Agricultural and Resource Economics
GPO Box 1563 Canberra ACT 2601

Telephone +61 2 6272 2000 Facsimile +61 2 6272 2001
Internet www.abareconomics.com

ABARE is a professionally independent government economic research agency.

ABARE project 2914

foreword

With rising natural gas demand and limited indigenous gas reserves in many Asia Pacific countries, imports of liquefied natural gas (LNG) have emerged as an important gas supply source in the region. Rapid growth in LNG consumption has occurred since imports commenced in Japan, Korea and Chinese Taipei. Now new and potential LNG markets are emerging in India, China, the Philippines, New Zealand and the west coast of north America, among others. The growth in Asia Pacific LNG demand has encouraged the rapid development of LNG export projects, both in the region, which has become the world's largest LNG supply source, and in the Middle East.

The outlook for LNG demand in the region is also strong, with Asia Pacific LNG imports projected to nearly double by 2015. The LNG demand outlook provides opportunities and challenges for LNG suppliers to the Asia Pacific market. Competition among existing LNG suppliers to retain markets will be strong, although there will be a key role for new projects. Potential regional LNG supply capacity in the coming decade is significant, although LNG projects are not expected to develop far ahead of imports.

The key objectives in this study are to review existing LNG trade in the Asia Pacific region and to assess likely future developments in the market over the period to 2015. Particular attention is given to the emerging US LNG market, including the possibility of LNG imports to the west coast of north America and the implications of this development for the broader Asia Pacific region.

BRIAN S. FISHER
Executive Director

November 2004

acknowledgments

The authors wish to thank several colleagues for their valuable contributions during the preparation of the report: in ABARE, Jara McKinlay, Sam Hester, Kevin Burns and Gerard Burg; and in the Australian Government Department of Industry, Tourism and Resources, Paul Kay and Peter Ferber.

In addition, the authors gratefully acknowledge the information, insights and comments on a draft report that were provided by BHP Billiton Ltd, Melbourne; Gorgon Australian LNG, Perth; North West Shelf Australia LNG Pty Ltd, Perth; Shell Development (Australia) Pty Ltd, Perth; Woodside Energy Ltd, Perth; and the Department of Industry and Resources, Perth.

Abbreviations used in this report include: bcm = billion cubic metres; Mt = million tonnes; Mtpa = million tonnes a year; MBtu = million British thermal units.

Conversions for natural gas and LNG

	billion cubic metres NG	billion cubic feet NG	million tonnes oil equivalent	million tonnes LNG	trillion British thermal units
1 billion cubic metres NG	1.00	35.30	0.90	0.73	36.00
1 billion cubic feet NG	0.028	1.00	0.026	0.021	1.03
1 million tonnes oil equivalent	1.111	39.20	1.00	0.805	40.40
1 million tonnes LNG	1.38	48.70	1.23	1.00	52.00
1 trillion British thermal units	0.028	0.98	0.025	0.02	1.00

Source: BP (2004).

contents

boxes

figures

tables

summary

Global demand for liquefied natural gas (LNG) has grown rapidly in recent years, particularly in the Asia Pacific region, where LNG imports are the primary source of gas in some countries. The outlook for LNG demand in the region is also strong, with Asia Pacific LNG imports projected to nearly double by 2015. Growth is expected to occur in both established and new LNG markets, including China and along the north American west coast.

The LNG demand outlook provides opportunities and challenges for LNG suppliers to the Asia Pacific market. Competition to retain markets among existing LNG suppliers will be strong, although there will be a key role for new projects. Potential regional LNG supply capacity in the coming decade is significant, although actual LNG output is not expected to develop far ahead of consumption, with many proposed projects likely to wait until markets have been secured.

The key objectives in this study are to review existing LNG demand and supply in the Asia Pacific region and to assess likely future developments in the market over the period to 2015.

The Asia Pacific LNG market

LNG demand

Demand for natural gas in the Asia Pacific region has more than quadrupled since 1980. Contributing factors include increased emphasis on environmental issues, the uptake of technologies such as combined cycle gas power plants, and the commercialisation of abundant gas reserves. Energy security and fuel diversification policies have also played an important role in encouraging gas demand as a means of reducing dependence on imported oil. With limited indigenous gas reserves in many Asia Pacific countries and few existing international gas pipelines, LNG imports have emerged as an important gas supply source in the region (table A).

A Natural gas consumption and the role of LNG, Asia Pacific, 2002

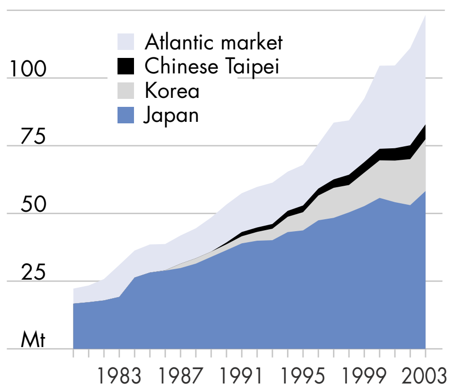
	Natural gas consumption	Gas share in primary energy consumption	Gas share in electricity generation	LNG imports	LNG share in gas supply
	bcm	%	%	Mt	%
Japan	75.5	12.8	22.5	53.0	96.4
Korea	23.1	11.1	12.7	17.8	100.0
Chinese Taipei	7.8	7.4	9.9	5.1	90.1
India	27.7	6.8	10.6	–	–
China	33.1	3.1	0.3	–	–
Philippines	1.6	4.5	18.1	–	–
New Zealand	6.1	28.1	25.1	–	–
California, US	64.4	26.7	48.7	–	–

Sources: IEA (2003a, 2004a,b); EIA (2003a, 2004a,b).

The Asia Pacific LNG market currently consists of buyers from Japan, the Republic of Korea (Korea), Chinese Taipei and, more recently, India, and is supplied by producers from south east Asia, Australia, north America and the Middle East. These countries have driven the expansion in the world LNG market over the past two decades (IEA 2003a; BP 2004; figure A). The Asia Pacific market accounted for two thirds of world LNG imports in 2003, or 83 million tonnes.

Japan is the world's largest LNG market, accounting for 70 per cent of Asia Pacific imports and nearly half of world trade in 2003. Korea is the region's fastest growing LNG market, accounting for 23 per cent of Asia Pacific LNG imports, while Chinese Taipei accounted for the remaining 7 per cent. LNG imports currently provide more than 97 per cent of gas requirements in these countries. India began importing LNG in early 2004 to supplement its domestic gas production.

A World LNG imports, by market



The number of countries importing LNG in the Asia Pacific region is likely to expand in the next few years, with China currently building two LNG receiving terminals. Several other countries, including the Philippines, New Zealand, Singapore and Thailand, as well as potential importers on the north American west coast, are considering or planning to introduce LNG.

B **LNG export plants, Asia Pacific and Middle East, 2004**

	Project	Capacity	Trains
		Mtpa	no.
Asia Pacific			
Alaska, US	Kenai	1.4	2
Australia	North West Shelf	11.7	4
Brunei	Brunei LNG	7.2	5
Indonesia	Arun	6.8	4
	Bontang	22.6	8
Malaysia	MLNG Satu	7.6	3
	MLNG Dua	7.8	3
	MLNG Tiga	6.8	2
Middle East			
Oman	Oman LNG	6.6	2
Qatar	Qatargas	8.3	3
	RasGas	11.3	3
UAE	Das Island	5.7	3
Total		103.8	42

Sources: EIA (2003b); FACTS Inc. (2004a).

LNG supply

In 2004, eight countries have regularly supplied LNG to the Asia Pacific market. These exporters have an annual liquefaction capacity of around 104 million tonnes from 42 LNG trains (table B). Of this total, five exporters located within the Asia Pacific region account for 72 million tonnes of annual liquefaction capacity, while the Middle East has 32 million tonnes of annual liquefaction capacity. Indonesia has the largest LNG export capacity, followed by Malaysia, Qatar and Australia.

LNG liquefaction capacity in the Asia Pacific and the Middle East is likely to expand in the next few years, with many exporters currently undertaking, or planning to undertake, expansions of existing facilities and/or new projects. In addition, the Russian Federation is currently constructing its first LNG plant to supply the Asia Pacific market, and several other countries, including Iran, Yemen, Bolivia and Peru, are considering the construction of liquefaction plants.

LNG marketing

The LNG market is predominantly based on long term sales contracts between buyers and suppliers. The use of long term contracts has enabled both parties to undertake the large scale infrastructure investment involved in LNG transactions with some certainty. However, LNG contracts have become more flexible in recent years. Some newer contracts include less rigid take or pay and/or destination clauses, free on board pricing, increased flexibility in the timing of deliveries, and a reduction in the linkage of LNG prices to crude oil prices.

The costs of liquefying, transporting and regasifying LNG have fallen significantly over the past two decades. This has come about mainly through improved design, greater competition and economies of scale from larger units. These cost decreases throughout the LNG chain are making LNG increasingly attractive to end users.

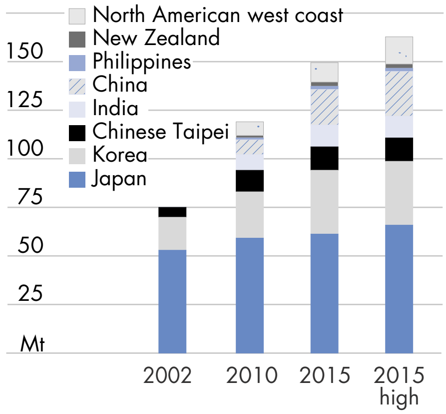
Outlook for Asia Pacific LNG demand

LNG imports in the Asia Pacific region are projected to expand by 5 per cent a year over the period to 2015, underpinned by strong economic growth and an increase in gas fired power generation. By 2010, Asia Pacific LNG imports are projected to reach 119 million tonnes, rising to 150 million tonnes by 2015 (figure B). Under a high demand scenario, LNG imports could reach 163 million tonnes in 2015. This compares with 83 million tonnes in 2003.

Despite projected slow growth, Japan is expected to remain the largest and among the most important LNG markets in the region, with imports reaching 61.4 million tonnes in 2015, or 66.0 million tonnes under a higher growth scenario. Korea is projected to remain the second largest Asia Pacific LNG market over the outlook period, while Chinese Taipei is also likely to remain a significant regional market. LNG imports in Korea and Chinese Taipei are projected to nearly double by 2015.

Two of the fastest growing LNG markets in the region are likely to be in India and China, with their LNG imports projected to reach 11 million tonnes and 18 million tonnes respectively by 2015. These two new markets are projected to account for about 40 per cent of growth in LNG imports in

B Projected LNG demand, Asia Pacific



the Asia Pacific region between 2002 and 2015, with China likely to become the third largest regional LNG destination. Prospects for LNG imports in both countries will be heavily influenced by the success of initial import projects.

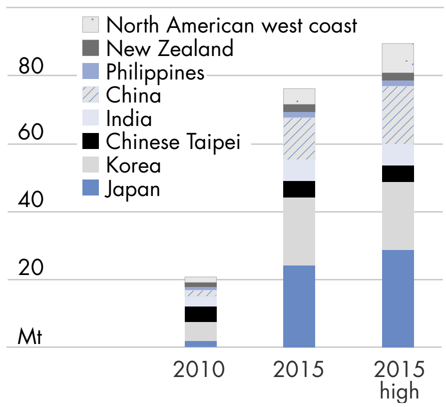
Potential LNG imports along the north American west coast could also contribute significantly to market growth in the Asia Pacific region. Underpinning interest in LNG in north America are high domestic gas prices, strong growth in demand for gas fired power generation, expected shortfalls in north American gas supplies, and the increasing competitiveness of LNG. While one LNG import terminal has been approved, the establishment of significant west coast LNG trade will depend on overcoming strong public opposition to the siting of terminals in California and Baja California in Mexico. It is projected that up to two LNG terminals could be located on the west coast by 2015, with imports likely to be limited more by terminal capacity and gas prices than by gas demand.

Uncontracted LNG demand

A significant proportion of future LNG demand in the Asia Pacific region will be met by existing long term LNG supply contracts. By 2010, more than three quarters of LNG imports are expected to be met by existing contractual supplies, leaving around 21 million tonnes of LNG for which new supplies will need to be procured. This assumes no renewal of existing long term contracts, except for those already officially announced.

By 2015, uncontracted LNG demand is expected to rise to around 76 million tonnes, or 51 per cent of projected demand, as LNG imports continue to grow and more existing long term LNG supply contracts expire. Under the high demand scenario, uncontracted regional LNG demand could rise to 89 million tonnes in 2015 (figure C). Japan accounts for nearly one third of projected uncontracted LNG demand in

C Projected uncontracted LNG demand, Asia Pacific



C Projected LNG demand, Asia Pacific

	LNG demand			Uncontracted LNG demand	
	2002	2010	2015	2010	2015
	Mt	Mt	Mt	Mt	Mt
Japan	53.0	59.3	61.4	1.7	24.0
Korea	17.8	23.8	32.9	5.7	19.9
Chinese Taipei	5.1	11.1	12.1	4.5	5.0
India	–	8.1	11.0	3.1	6.2
China	–	7.7	18.3	1.8	12.4
Philippines	–	1.0	1.7	1.0	1.7
New Zealand	–	1.3	2.2	1.3	2.2
North American west coast	–	7.0	10.0	1.7	4.7
Total	75.9	119.2	149.7	20.7	76.2

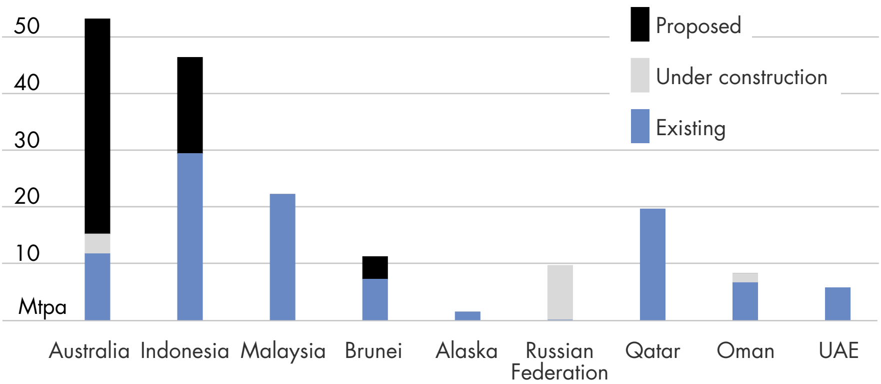
2015, while significant potential supply shortfalls are also evident in Korea and China (table C). Some proportion of uncontracted demand in existing markets is likely to be met through contract renewals with current long term suppliers.

Outlook for LNG supply to the Asia Pacific region

The outlook for LNG demand in the Asia Pacific region implies a large increase in LNG supply will be required over the period to 2015. There is currently an additional 15 million tonnes of LNG capacity under construction that is expected to supply Asia Pacific LNG markets in the next few years. This figure includes 3.5 million tonnes by 2006 from Darwin LNG in Australia, and 9.6 million tonnes by 2008 from Sakhalin 2 in the Russian Federation (figure D). By 2010, regional LNG supply from existing LNG suppliers and those with capacity under construction could be 110 million tonnes. This compares with projected Asia Pacific LNG demand in 2010 of 119 million tonnes, implying further projects will be required by the end of the decade. Indeed, with few projects due on line over the short term, LNG supplies to the region may be tight, particularly to meet unexpected demand.

A further ten projects are proposed in existing LNG supplying countries in the Asia Pacific region. Most of these projects are proposed to come on line

D Potential LNG supply capacity for the Asia Pacific market, by country



between 2007 and 2011. The proposed projects have a combined annual liquefaction capacity of 59 million tonnes, raising the potential LNG supply capacity to the Asia Pacific market to 169 million tonnes in 2015. The majority of the proposed LNG capacity additions are concentrated in Australia and Indonesia (figure D). There could also be additional LNG supplies available from Qatar to supply Asia Pacific markets, depending on developments in Atlantic markets where the significant planned Qatari capacity expansions are targeted.

Several projects planned in Iran, Yemen, Peru and Bolivia could also supply Asia Pacific markets by 2015. However, there are some additional uncertainties attached to developing LNG projects in these countries, including public opposition, environmental concerns, geopolitical issues, political instability and progress in LNG marketing to date. Strong competition among suppliers to secure LNG markets in the Asia Pacific region could make it more difficult for such projects to proceed in the next ten years, with buyers taking a range of factors (including price, flexibility, security and reliability) into account when making LNG procurement decisions.

Asia Pacific LNG demand and supply balance

LNG projects are not likely to come on line until there is sufficient demand to underpin the required investment. A number of the projects proposed to be operational by the end of the decade have already been marketed for several years, and their development date postponed until LNG markets are secured. Considering the volume of potential LNG supply projects and the outlook for LNG demand in the region, not all projects are likely to materialise in the period to 2015. Competition to secure markets in the Asia Pacific region in order to launch projects is thus expected to be strong. Delays in project approval processes, including to resolve environmental and boundary issues, could mean start up dates for some projects are postponed for several years as other suppliers capture potential market opportunities.

As in the past, the actual development of regional LNG supply capacity is not expected to be far ahead of demand in the coming decade. Indeed, LNG supply in the next few years may be tight in the Asia Pacific market, especially if demand exceeds current forecasts, because few projects are expected to come on line in this period, and supply from proposed projects will take some years to become available.

Australia is one of the largest potential suppliers of LNG to the Asia Pacific region, with several proposed projects over the coming decade that could more than quadruple Australian LNG supply capacity. As with other projects in the region, Australia will face strong competition to secure markets in this timeframe, including competition from Indonesia, the Russian Federation and the Middle East. However, with LNG buyers taking price, flexibility, diversity, political security and reliability into account when making purchasing decisions, the outlook for the Australian LNG industry in the coming decade remains strong.

1

introduction

Global demand for natural gas has increased strongly over the past three decades, and gas now accounts for one quarter of the world's primary energy consumption. Natural gas has been the fastest growing fossil fuel over this period. This trend reflects a range of factors, including the favorable environmental characteristics of natural gas compared with coal and oil, and the pursuit of energy security and fuel diversification policies in some economies. Other contributing factors include the abundance of global gas reserves, increasingly competitive pricing in particular applications and rapid advances in gas fired power generation technologies. For similar reasons, natural gas consumption is expected to continue to expand over the coming decades.

While gas consumption has risen strongly, indigenous gas production in many countries has not expanded at a similar pace. With many of the world's gas reserves located far from centres of demand, gas trade has become increasingly important. In particular, trade in liquefied natural gas (LNG) has increased in prominence in recent years. LNG trade expanded more than fivefold over the past two decades to reach 123 million tonnes in 2003, or around 6 per cent of world gas consumption.

Much of the expansion in LNG trade has been in the Asia Pacific region, where three countries — Japan, the Republic of Korea (Korea) and Chinese Taipei — together accounted for two thirds of world LNG imports in 2003. With limited domestic gas reserves and no international pipeline connections to alternative gas sources, LNG imports have been essential to fuelling gas demand in these markets. LNG currently accounts for 97 per cent of gas consumption in Japan, Korea and Chinese Taipei. LNG demand in these countries is expected to continue to expand, supported by economic growth, ongoing energy security concerns and the declining unit costs of LNG projects, as well as to address environmental issues.

In addition to growth in established markets, LNG demand is expected to increase in new markets, including in India and China. India's first LNG imports commenced in early 2004, while China is expected to begin importing LNG in 2006. In both countries, high rates of economic growth, increasing demand for energy (particularly electricity), severe urban air quality problems, and government policies favorable toward natural gas are likely to contribute to substantial additional requirements in the future, with LNG expected to supplement domestic gas supplies. Several other countries in the region that are facing energy security issues and limited or declining domestic gas reserves are also exploring the option of LNG imports. These include the Philippines, New Zealand, Singapore and Thailand.

In addition, the US LNG market more than doubled in size during 2003, and the United States has the potential to become a major importer of LNG in the coming years. The renewed interest in LNG imports into the United States has been driven by recent high domestic gas prices, predicted declines in Canadian pipeline imports, and changes to regulatory arrangements for new LNG terminals. As part of the anticipated growth, there is potential to introduce LNG imports to the north American west coast. Such a development would have implications for the broader Asia Pacific LNG outlook.

The projected expansion in LNG consumption in the Asia Pacific region will require significant investment in LNG supply capacity. The region is currently the largest supplier of LNG in the world, and the five exporters — Australia, Brunei, Indonesia, Malaysia and Alaska — accounted for almost half of the world market in 2003. The expected growth in demand will provide opportunities for these LNG suppliers, many of which have new capacity under construction and/or proposed either through expansion or greenfield projects.

However, competition to supply Asia Pacific LNG markets is likely to remain strong. Significant expansions in LNG capacity are also planned in Middle Eastern countries, particularly in Qatar. In addition, the Russian Federation is constructing its first LNG liquefaction plant on Sakhalin Island, which is expected to begin supplying the Asia Pacific market toward the end of the decade. Both Iran and Yemen are also exploring options to export LNG to Asia, while Bolivia and Peru have proposed LNG export projects targeting the north American west coast.

A number of other factors will shape the Asia Pacific LNG market in the coming decade. All existing LNG markets in the region and most new and potential markets are implementing some form of deregulation and privatisation of their electricity and gas sectors. This is likely to increase the importance to buyers of flexibility and competitive prices in LNG contracts. Long term LNG contracts are becoming more flexible, including free on board pricing, less rigid take or pay clauses, and seasonal delivery schedules. On the supply side, LNG production and shipping facilities are becoming larger and more efficient, and their unit costs have been declining. Some LNG projects are proceeding with fewer sales contracts in place, although the LNG industry is unlikely to move significantly away from long term supply agreements underpinning investment.

There are also possibilities for several international gas pipelines in the Asia Pacific region, including pipelines from the Russian Federation to China, Japan and Korea, from Bangladesh and Iran to India, and between several Association of South East Asian Nations (ASEAN) members. The construction of these international pipelines would introduce some gas on gas competition in the Asia Pacific market and could have implications for LNG demand and pricing. However, given the nature of issues associated with international pipeline development in the region, including geopolitical concerns, LNG is likely to continue to provide much of the region's gas imports in the short to medium term.

Objectives in the study

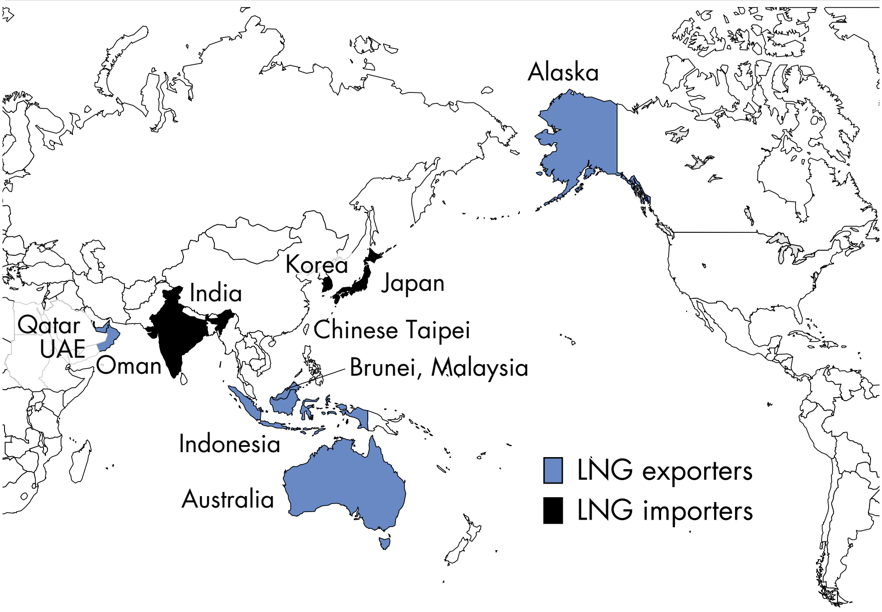
The key objectives in the study are to review existing LNG demand and supply in the Asia Pacific region (figure 1) and to assess likely future developments in the market over the period to 2015.

The report includes an overview of the current trends in the Asia Pacific LNG market. Individual LNG markets in the Asia Pacific region are profiled, and an outlook for LNG demand in each market over the coming decade is developed. The established, new and potential LNG markets considered in detail include Japan, Korea, Chinese Taipei, India, China, the Philippines and New Zealand. Particular attention is given to the US LNG market, including the possibility of LNG imports to the west coast of north America and the implications of this development for the broader Asia Pacific region.

Profiles of existing and known future LNG suppliers to the Asia Pacific market are also provided in the report, including their existing and potential supply capacity over the outlook period. The exporters considered comprise Australia, Indonesia, Malaysia, Brunei, Alaska, Qatar, Oman, the United Arab Emirates and the Russian Federation.

Based on the demand and supply capacity projections presented in the report, an indicative LNG demand and supply balance for the Asia Pacific region is developed. Some of the key issues affecting the outlook for LNG — including energy market reform, changing LNG contract conditions, recent trends in LNG projects, and the development of gas pipelines in the region — are also discussed.

1 The Asia Pacific LNG market, 2004



2

the Asia Pacific LNG market

The demand for natural gas has grown steadily over the past two decades or more, especially in the Asia Pacific region where gas consumption has more than quadrupled since 1980. Contributing factors include increased emphasis on environmental issues, which favors the clean combustion properties of gas relative to other fossil fuels, the uptake of technologies such as combined cycle gas power plants, and the commercialisation of abundant gas reserves. Energy security and fuel diversification policies have also played an important role in encouraging gas demand as a means of reducing dependence on imported oil.

With limited indigenous gas reserves in many Asia Pacific countries, imports of liquefied natural gas (LNG) have emerged as an important gas supply source in the region. Rapid growth in LNG consumption has occurred since imports commenced in Japan, the Republic of Korea (Korea) and Chinese Taipei. Now new and potential LNG markets are emerging in India, China, the Philippines, New Zealand and along the west coast of north America, among others. The growth in Asia Pacific LNG demand has encouraged the rapid development of LNG export projects, both in the region, which has become the world's largest LNG supply source, and in the Middle East.

Natural gas consumption overview

World natural gas consumption has increased at an average annual rate of 2.6 per cent over the past two decades, to reach 2.6 trillion cubic metres in 2002 (equivalent to 1.9 billion tonnes of LNG). This compares with growth in total primary energy consumption of 1.6 per cent a year over the same period. As a result, the share of natural gas in world primary energy consumption rose to 24 per cent in 2002, compared with 19 per cent in 1980 (table 1).

The Asia Pacific region accounted for 13 per cent of world natural gas consumption in 2002, or around 338 billion cubic metres (equivalent to 247 million tonnes of LNG) (IEA 2003a; figure 2). Consumption of natural gas in the region has grown more rapidly than the world average, at an annual rate of 7.5 per cent since 1980. In addition, the share of gas in primary

1 Natural gas consumption and trade, Asia Pacific and world

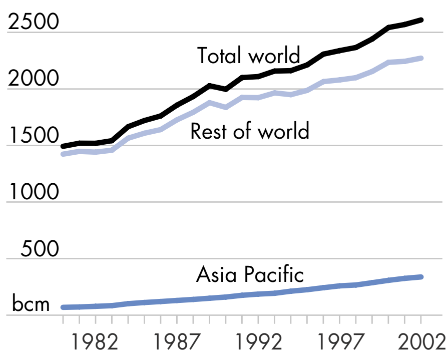
		Asia Pacific			World		
		1980	2002	1980 –2002 a	1980	2002	1980 –2002 a
				%			%
Total primary energy consumption **b**	Mtoe	1 135	2 682	4.0	6 376	9 113	1.6
Natural gas consumption	bcm	69	338	7.5	1 492	2 569	2.6
Share of gas in TPEC	%	5	11	–	19	24	–
Natural gas imports	bcm	23	119	7.8	195	704	6.0
Share of imports in gas consumption	%	33	35	–	13	27	–
LNG imports	Mt	17	76	7.2	22	111	7.7

a Average annual growth. **b** Total primary energy consumption (TPEC) excludes combustible renewables and waste.
Sources: IEA (2003a, 2004a,b).

energy consumption has doubled in the Asia Pacific region over the past two decades to reach around 11 per cent. However, the role of gas in the regional energy mix is still considerably lower than the world average (table 1).

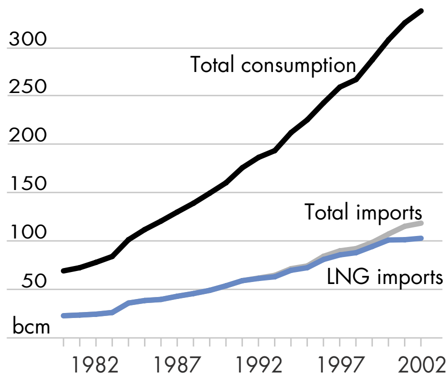
With many natural gas reserves located some distance from key gas consuming countries, world gas trade has increased as a proportion of total consumption. In 2002, 27 per cent of world gas consumption was supplied via international trade, with trade reaching 704 billion cubic metres (equivalent to 514 million tonnes of LNG). However, this trend has not been observed in the Asia Pacific region, where the share of gas imports has remained relatively constant over the past two decades at around one third of total gas consumption. A key difference in the Asia Pacific region is that countries such as Japan and Korea have traditionally based much of their gas consumption around imports, whereas many gas consumers in

2 Natural gas consumption, Asia Pacific and world



other parts of the world, including the United States and the European Union, are becoming increasingly reliant on imports to complement domestic production.

3 **Natural gas consumption and imports, Asia Pacific**



More than three quarters of world gas trade in 2002 was via international pipelines. LNG imports accounted for 22 per cent of total world gas trade in that year, equal to around 6 per cent of world gas consumption (box 1). With fewer international gas pipelines in the region, the proportion of gas trade met by LNG imports is much higher in the Asia Pacific, at around 87 per cent in 2002 (IEA 2003a; figure 3). The remaining trade consists of pipeline exports from Indonesia and Malaysia to Singapore, and from Myanmar to Thailand.

LNG market characteristics

World LNG trade is characterised by a small number of suppliers and buyers. There are currently twelve countries that export LNG and fourteen LNG importing countries (table 2). Globally, there are two distinct LNG markets: the Asia Pacific market and the Atlantic market. The Asia Pacific market currently consists of buyers from Japan, Korea, Chinese Taipei and, more recently, India, supplied by producers from south east Asia, Australia, north America and the Middle East. The Atlantic market consists of buyers in north America and Europe, supplied predominantly by producers from north Africa, the Middle East and the Caribbean.

2 **LNG exporters and importers**

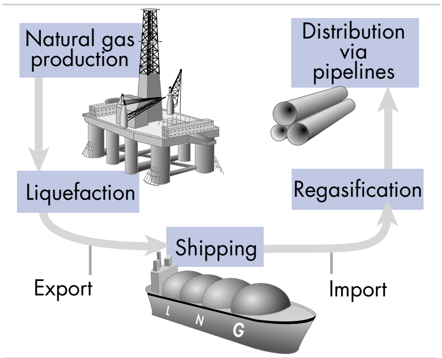
Exporters	Importers
Algeria	Belgium
Australia	Chinese Taipei
Brunei Darussalam	Dominican Republic
Indonesia	France
Libya	Greece
Malaysia	India
Nigeria	Italy
Oman	Japan
Qatar	Portugal
Trinidad and Tobago	Puerto Rico
United Arab Emirates	Republic of Korea
United States, Alaska	Spain
	Turkey
	United States

Box 1: **What is LNG?**

Liquefied natural gas (LNG) is natural gas that is cooled to a temperature of –161° C, at which point it becomes a liquid. Liquefying natural gas reduces its volume by a factor of 610, which assists in storage and distribution to market. Liquefaction provides a means of transporting natural gas long distances when pipeline transport is not viable or possible.

Natural gas is turned into a liquid using a refrigeration process in a liquefaction plant. The unit where LNG is produced is called a train. A liquefaction plant comprises one or more LNG trains, and individual trains may vary in size. In international trade, LNG is transported at atmospheric pressure in specially built tanks in double hulled ships to a receiving terminal where it is stored in heavily insulated tanks. The LNG is then sent to regasifiers, which turn the liquid back into a gas. The gas then enters the pipeline system for distribution to customers (figure 4).

4 The LNG supply chain



Generally, natural gas is measured in metric tonnes when it is a liquid, and in cubic metres or cubic feet when it is in its gaseous state. One million metric tonnes of LNG is equivalent to 1.38 billion cubic metres or 48.7 billion cubic feet of natural gas.

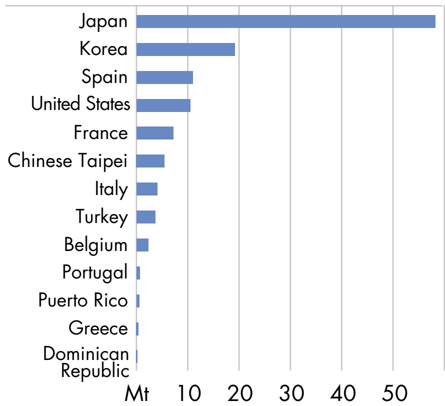
Sources: EIA (2003b); BP (2004).

There can, however, be spillover between markets, especially in spot trades. Australia, for example, has exported several LNG cargoes to Spain, Turkey and the United States on a spot market basis. While geographic separation and LNG transport costs mean that LNG pricing, demand and supply in the Asia Pacific market have traditionally been relatively distinct from and unaffected by the Atlantic market, LNG markets are becoming more integrated (box 2, page 25).

LNG demand

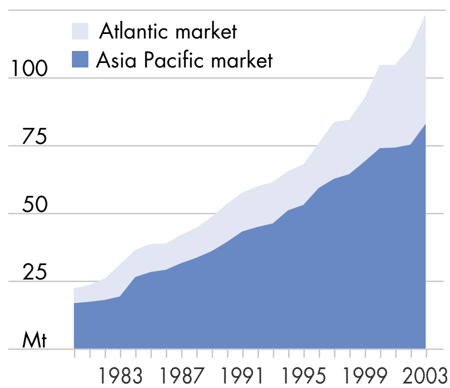
World consumption of LNG has increased more than fivefold over the past two decades, with LNG imports rising at an average annual rate of 7.7 per cent to 123 million tonnes in 2003. This compares with 22 million tonnes in 1980 (IEA 2003a; BP 2004). In addition to strong consumption growth in many economies, the number of countries importing LNG increased from five in 1980 to thirteen in 2003. Japan is the world's largest LNG importer, accounting for almost half of world LNG trade in 2003, followed by Korea, Spain and the United States (BP 2004; figure 5).

5 World LNG imports, by country, 2003



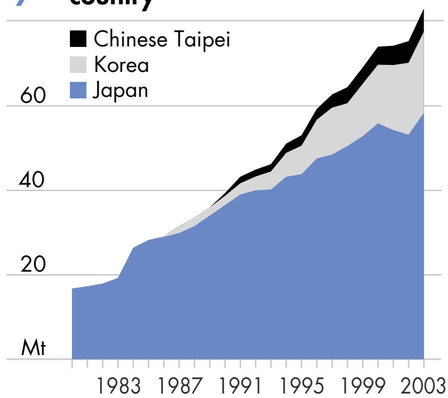
The growth in world LNG consumption over the past two decades has occurred mainly in the Asia Pacific market. The region accounted for two thirds of world LNG imports in 2003, or around 83 million tonnes, compared with 17 million tonnes in 1980 (IEA 2003a; BP 2004; figure 6). There were three countries importing LNG in the Asia Pacific market in 2003: Japan, Korea and Chinese Taipei. These countries have little or no domestic gas production and no existing international gas pipelines. LNG imports into the region thus increased rapidly in the 1980s and 1990s, as these countries sought alternatives to oil that were also environmentally friendly. India began importing LNG in early 2004 to supplement its domestic gas production.

6 World LNG imports, by market



As the world's largest LNG importer by a significant margin, Japan has been a key driver of LNG consumption in the Asia Pacific region (IEA 2003a; BP 2004; figure 7). It accounted for 70 per cent of Asia Pacific LNG imports in 2003. Korea began importing LNG in 1986 and has since recorded the strongest growth in LNG consumption in the region. It now accounts for around 23 per cent of Asia Pacific LNG trade. Chinese Taipei began importing LNG in 1990 and was the smallest LNG market in the region in 2003, consuming around 7 per cent of Asia Pacific LNG imports.

7 Asia Pacific LNG imports, by country



There are currently thirty LNG receiving terminals in the Asia Pacific region, 25 of which are located in Japan (table 3). There are three terminals in Korea, and one each in Chinese Taipei and India. The region's combined annual import capacity is around 245 million tonnes — significantly greater than the 83 million tonnes of LNG imported in 2003. This enables countries to meet variable seasonal requirements.

3 Existing LNG receiving terminals, Asia Pacific

Importer	Terminals	Capacity	Imports 2003
	no.	Mtpa	Mt
Japan	25	194.1	58.2
Korea	3	40.7	19.1
Chinese Taipei	1	7.4	5.5
India	1	5.0	–
Total	30	247.2	82.8

Sources: EIA (2003b); Suzuki and Morikawa (2003); Energy Commission (2003); Energy Argus (2004a); BP (2004).

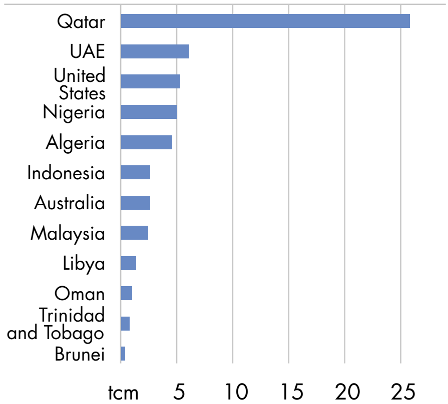
The number of LNG importing countries in the Asia Pacific region is likely to expand in the next few years, with China currently building two LNG receiving terminals. Several other countries in the region, including the Philippines, New Zealand, Singapore and Thailand and along the north American west coast, are discussing or planning to introduce LNG imports.

LNG supply

Gas reserves

World natural gas reserves are abundant. Proved recoverable reserves of natural gas — defined as the volumes in place that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions — are estimated to be 176 trillion cubic metres (equivalent to 128 billion tonnes of LNG) at end 2003. This volume is around 67 times the volume of natural gas currently produced (BP 2004). Much of this gas is considered stranded because it is located in regions distant from consuming markets.

8 **Proven recoverable gas reserves in LNG exporting countries**
end 2003



The Russian Federation and Iran have the world's largest proved recoverable natural gas reserves (47 and 27 trillion cubic metres respectively). While they do not export LNG, both countries have plans to do so by the end of the decade. The 12 countries that currently export LNG contain approximately one third of world proven recoverable gas reserves, or around 57 trillion cubic metres in total. The most significant gas reserves by far are in Qatar, followed by the United Arab Emirates and the United States (BP 2004; figure 8). Among the LNG exporters in the Asia Pacific region, the largest proven recoverable gas reserves are located in Indonesia, Australia and Malaysia.

LNG production capacity

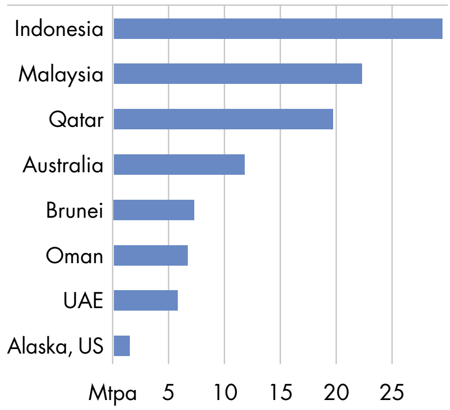
Of the twelve LNG exporting countries, eight countries currently supply LNG to the Asia Pacific region on a regular basis. Asia Pacific LNG markets are supplied both from within the region and from the Middle East. Other LNG suppliers in Africa and the Caribbean are generally too distant, given current transport costs.

In late 2004, LNG suppliers to the Asia Pacific market had an annual LNG liquefaction capacity of around 104 million tonnes from 42 LNG trains. Of this total, the five exporters located within the Asia Pacific region account for 72 million tonnes of annual liquefaction capacity, while there is 32 million tonnes of annual capacity in the Middle East. Of these exporters, Indonesia has the largest LNG production capacity, accounting for 28 per cent, followed by Malaysia, Qatar and Australia (figure 9; table 4).

LNG production capacity to serve the Asia Pacific market has expanded strongly over the past two decades, particularly through LNG projects located within the region. However, the emergence of the new Middle East suppliers, Qatar and Oman, has driven much of the recent growth in LNG capacity (figure 10). While most of the capacity in the Middle East is dedicated to supplying the Asia Pacific market, Middle Eastern suppliers also export to Atlantic markets.

LNG liquefaction capacity in the Asia Pacific and the Middle East is likely to expand in the next few years, with many LNG exporters currently undertaking, or planning to undertake, expansions of existing facilities and/or new projects. In addition, the Russian Federation is constructing its first LNG liquefaction plant on Sakhalin Island to supply the Asia Pacific market, and several other countries (including Iran, Yemen, Bolivia and Peru) are considering the construction of LNG liquefaction plants.

9 **LNG liquefaction capacity, Asia Pacific and Middle East, 2004**

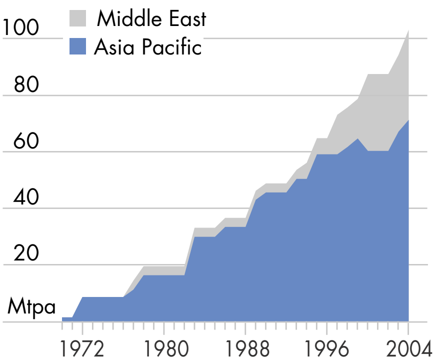


4 **LNG liquefaction plants, Asia Pacific and Middle East, 2004**

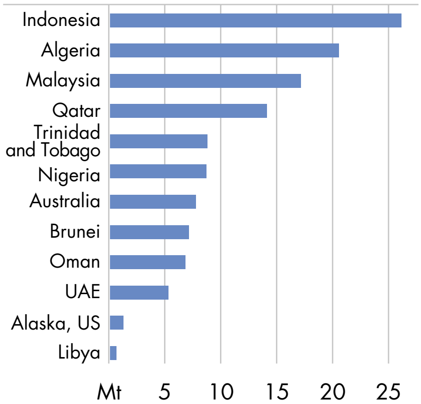
	Project	Capacity	Trains
		Mtpa	no.
Asia Pacific			
Alaska, US	Kenai	1.4	2
Australia	North West Shelf	11.7	4
Brunei	Brunei LNG	7.2	5
Indonesia	Arun	6.8	4
	Bontang	22.6	8
Malaysia	MLNG Satu	7.6	3
	MLNG Dua	7.8	3
	MLNG Tiga	6.8	2
Middle East			
Oman	Oman LNG	6.6	2
Qatar	Qatargas	8.3	3
	RasGas	11.3	3
UAE	Das Island	5.7	3
Total		103.8	42

Sources: EIA (2003b); FACTS Inc. (2004a).

10 **LNG liquefaction capacity, Asia Pacific and Middle East**



11 **World LNG exports, by country, 2003**

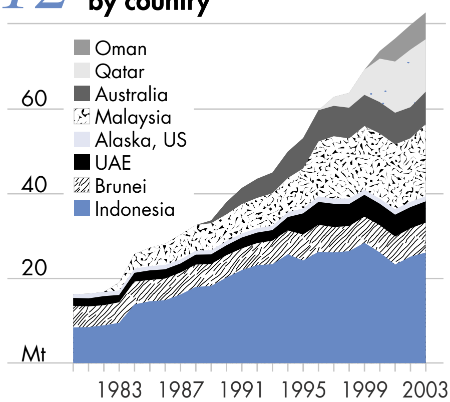


LNG exports

LNG suppliers located in the Asia Pacific region exported 59 million tonnes of LNG in 2003. The region is the world's largest LNG producer, supplying close to half of global LNG trade in that year. Indonesia alone supplied 21 per cent of world LNG exports (BP 2004; figure 11). The three exporters in the Middle East supplied 26 million tonnes of LNG in 2003, equivalent to 23 per cent of total world LNG production. The remaining 29 per cent was supplied by four countries serving the Atlantic market.

Indonesia accounted for 32 per cent of LNG exports to the Asia Pacific market in 2003 (BP 2004; figure 12). This share of the market declined from more than half throughout the 1980s and early 1990s as new suppliers emerged and two trains at Indonesia's Arun plant were decommissioned in 2000. In 2003, Malaysia and Qatar accounted for 21 and 15 per cent of the Asia Pacific market respectively. In the same year, Australia accounted for 9 per cent.

12 **LNG exports to Asia Pacific, by country**

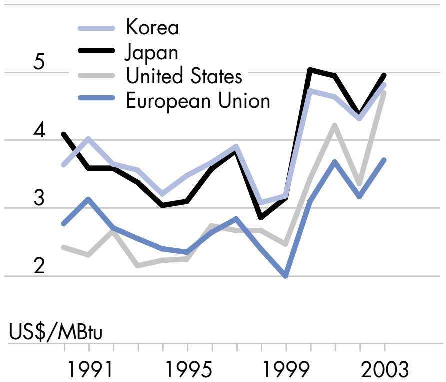


Other characteristics of the market

Prices

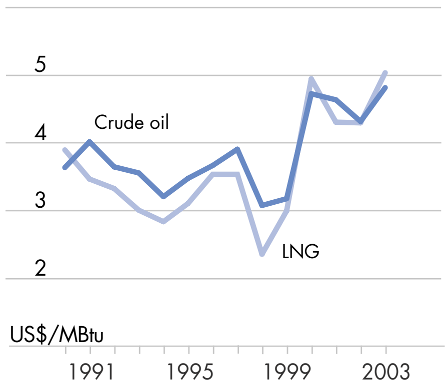
The existence of relatively distinct regional markets for LNG has led to different pricing outcomes, although gas prices in each market exhibit some degree of integration (box 2, page 25). LNG prices have historically been higher in the Asia Pacific market than in the Atlantic market (IEA 2004c; EIA 2004a; figure 13). In Japan and Korea, nominal LNG import prices from all sources have averaged US$3.85/MBtu and US$3.82/MBtu respectively since 1990. This compares with US$2.82/MBtu in Europe and US$2.88/MBtu in the United States over the same period. However, LNG import prices rose sharply in the United States during 2003 (in line with high domestic prices) to an average US$4.70/MBtu, similar to LNG prices in Japan and Korea in that year.

13 Average LNG import prices, by market cif average all sources



LNG import prices are typically benchmarked to competing fuels. In the Asia Pacific market, LNG prices have generally been linked to the average price of imported crude oil as measured by the Japanese custom cleared crude oil price (JCC). Reflecting this link, regional LNG prices followed oil price movements fairly closely over the past decade. Higher LNG import prices in Japan and Korea since 2000, for example, have reflected higher international oil prices during this period (IEA 2004c; figure 14).

14 Average LNG and crude oil import prices, Japan



In Europe, LNG prices are related to those of competing fuels such as low sulfur residual fuel oil, although LNG prices are now beginning to be linked to natural gas spot and futures market prices in some countries. In the United States, the competing fuel for LNG pricing purposes is pipeline natural gas, and the benchmark is usually the Henry Hub price. As such, importers and exporters involved in US LNG transactions are exposed to a significant level of risk given the high degree of price volatility in US natural gas markets (EIA 2003b). LNG prices in the United States are discussed in chapter 5.

Contracts

The LNG market is predominantly based on long term sales contracts between buyers and sellers. Long term supply contracts in the Asia Pacific market tend to be around 20 years in duration and often include take or pay and destination clauses. The use of long term contracts has enabled both buyers and sellers to undertake the large scale infrastructure investment involved in LNG transactions with some certainty.

However, LNG contracts have become more flexible in recent years. Some of the newer contracts include less rigid take or pay and/or destination clauses, and free on board pricing. Buyers thus have more control over import destination and the ability to swap cargoes among themselves. Other recent changes in some contracts include increased flexibility in the timing of deliveries, and a reduction in the linkage of LNG prices to crude oil prices. Weakening the link to crude oil prices limits the subsequent fluctuation in LNG prices when oil prices rise or fall.

Further, a number of LNG supply projects are being developed with a smaller share of production secured under long term contracts than in previous projects. Recent examples include MLNG Tiga and the Russian Federation's Sakhalin 2 project, the latter of which announced its final investment decision following sales agreements that amounted to less than half the capacity of the first of two proposed trains (Sakhalin Energy 2003).

The increased flexibility and availability of cargoes have facilitated an increase in short term and spot trading of LNG, which grew from 1 per cent of the market in 1992 to 8 per cent (8.4 million tonnes) in 2002 (IEA 2003a). More than 40 per cent of spot sales were directed to the US market, while Korea also purchased a large number of spot cargoes to meet seasonal requirements.

LNG production costs

LNG projects are capital intensive, and upfront costs to construct liquefaction and regasification plants and specially designed LNG tankers are high. A single LNG chain involves investment of around US$5 billion for a typical 6.6 million tonne two train project involving a shipping distance of around 4000 kilometres (IEA 2003b). The lead time required to develop LNG projects is significant: construction can take more than three years and is preceded by an extended period of tendering, design and LNG marketing.

However, the costs of liquefying, transporting and regasifying LNG have fallen significantly over the past two decades. This fall has come about mainly through improved design, greater competition and economies of scale from larger units. These cost decreases throughout the LNG chain are making LNG increasingly competitive with some domestic and international pipeline gas sources and other fuels. These issues are discussed in more detail in chapter 4.

LNG transport

LNG transport generally involves large distances to markets, and LNG transport costs are distance and time sensitive. As such, transport costs can involve a significant component of overall LNG costs: shipping accounts for 10 to 30 per cent of the delivered cost of LNG, depending on the distance from the production facility to the market (EIA 2003b).

5 LNG shipping distance to Japan

Country	'000 km
Australia, North West Shelf	6.8
Brunei	4.4
Indonesia, Arun	6.1
Indonesia, Bontang	4.6
Malaysia	4.6
Oman	11.0
Qatar	11.9
Russian Federation, Sakhalin	1.7
United Arab Emirates	11.9
United States, Alaska	6.0

Sources: Wybrew-Bond and Stern (2002); Suzuki and Morikawa (2003).

Indicative shipping distances in the Asia Pacific market, based on Japan, are outlined in table 5. Distance to market for existing Japanese suppliers ranges from around 4400 kilometres from Brunei to just under 12 000 kilometres from Qatar and the United Arab Emirates. The Russian Federation's Sakhalin 2 LNG project, currently under construction, is around 1700 kilometres from Japan.

Box 2: **A global LNG market?**

LNG markets have traditionally been regional in nature, reflecting their geographic separation and the high costs of LNG transport. LNG prices also tend to be regional and are typically benchmarked to competing fuels in each market. In the Asia Pacific region, LNG prices are generally linked to the average price of imported crude oil into Japan. In Europe, LNG prices are linked to low sulfur residual fuel oil and other oil products, while in the United States, LNG prices are linked to pipeline natural gas prices.

Despite these differences, gas prices in each market exhibit some degree of integration, although not to the same extent as other commodities such as oil. LNG prices fell in Japan, Korea, Europe and the United States in 2002, and all rose again in 2003, reflecting both domestic and international factors. In Asia and Europe, LNG prices can move in similar ways because they are both linked to the price of crude oil or petroleum products (Howard 2004). There is less integration between prices in north America and Europe (L'Hégaret et al. 2003).

As a means of transporting gas between regions, LNG provides a link between individual gas markets. While LNG trade is dominated by long term contracts between regional players, LNG trade at the margin is becoming more responsive to short term market trends. Imports of spot LNG cargoes increased in all regions in 2003, in response to increased demand in local markets. These drivers included high gas prices in the United States, the closure of nuclear power plants in Japan, and a surge in gas fired electricity generation in Europe (Howard 2004). When one gas market is tight and another market is in surplus, LNG cargoes are being diverted to the stronger market. Price arbitrage regularly occurs, particularly between European and US markets.

This trend is supported by the increasing flexibility in LNG trade, which allows LNG players to be more responsive to market shifts than in the past. The fact that more contracts are designated in free on board terms, for example, means that customers are able to divert surplus cargos to other markets, subject to destination clauses. Buyers increasingly own or charter their own tanker fleet, allowing for greater control over delivery and destination and lower shipping costs. Some liquefaction plants have recently been built without firm contracts in place for all capacity, while some recent long term contracts have smaller offtake volumes in the initial years. As the volumes available to switch between markets increase and as flexibility in LNG contracts grows, arbitrage opportunities are expected to expand and the price link between LNG markets is likely to grow stronger (Howard 2004).

continued

Box 2: **A global LNG market?** *continued*

The growing number and diversity of LNG suppliers and markets will provide increasing choice and competition in LNG trade. This should also contribute to a convergence of global prices, as suppliers become actively involved in several markets (Brinded 2003). Suppliers in the Middle East in particular are well situated to continue to operate in both Asia Pacific and Atlantic LNG markets.

However, the logistics inherent to LNG trade suggest that there are limits to global integration of LNG markets, at least in the coming decade (Howard 2004). The predominance of long term LNG supply contracts restricts the impact of one gas market on another: with volumes determined by contract and prices set by formula, there is limited opportunity for transmission of market conditions between markets. If take or pay and destination contract clauses are enforced, arbitrage opportunities are likely to be constrained. Further, the time horizon of current long term LNG supply contracts is likely to limit the degree of integration, as it will take some years for significant volumes of current contracts to expire and for future flexibility in new contracts to become widespread.

Other limiting factors include the distance between LNG markets, the high proportion of transport costs in overall LNG costs, and the higher costs associated with shipping LNG over longer distances, including cargo boil off. There is also limited flexible tanker capacity to respond to market opportunities. In addition, LNG tankers are not compatible with all receiving ports, and the quality of the LNG must also meet the specifications of the regasification terminal.

LNG is transported in specially built tanks in double hulled ships. As of April 2004, there were 156 LNG tankers in the world LNG fleet, with 62 tankers on order for delivery by the end of 2007 (Bainbridge 2004). LNG tankers are generally sized between 138 000 and 145 000 cubic metres, which can carry around 60 000 to 70 000 tonnes of LNG per voyage. The tankers are generally tied to a particular project. However, this arrangement is gradually changing as the number of LNG buyers and sellers, as well as shipping companies, owning LNG tankers begins to grow. This trend is expected to assist in delivery flexibility and short term trading.

3

regional LNG demand: recent trends and outlook

Many factors will affect the outlook for natural gas demand and the role of liquefied natural gas (LNG) in Asia Pacific markets over the coming decade. These include economic growth, energy market reform, energy security issues, uncertainty surrounding the role of nuclear power, environmental and sustainable development policies, the pace of gas infrastructure development, and gas pricing and marketing arrangements. Many of these factors are relevant to several, if not all, of the economies in the region. The following section contains a brief discussion of each factor and how it could affect the outlook for gas demand, including relevant examples from individual markets.

Also presented in this chapter are profiles of key LNG markets in the Asia Pacific region. These include the current LNG markets of Japan, the Republic of Korea (Korea), Chinese Taipei and India, and the emerging and potential markets of China, the Philippines and New Zealand (figure 15). The US LNG market, with emphasis on the potential north American west coast market, is covered in chapter 5. Each profile includes an overview of the economy and energy system, natural gas consumption, sources of gas supply, and the role of LNG imports. Also included is an outlook for natural gas demand over the next decade in each market and a possible LNG demand and supply balance for that country.

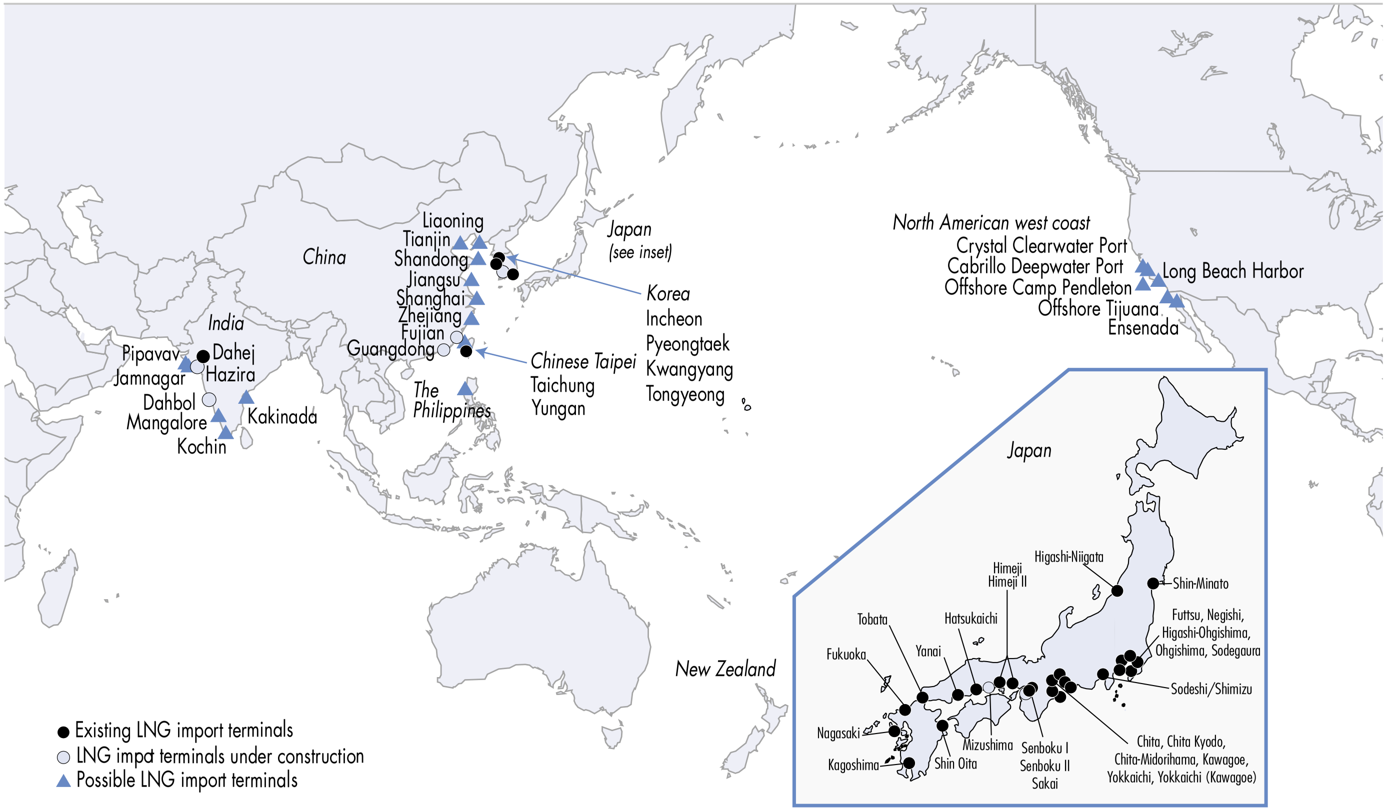
The projections for natural gas demand are based on results from ABARE's global trade and environment model (GTEM). A brief outline of the modeling framework is provided in box 3 (page 30).

Factors affecting future LNG demand

Economic growth

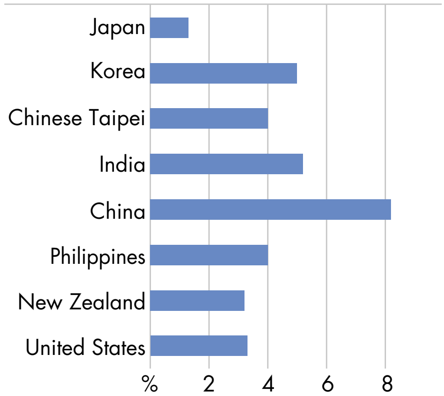
The outlook for economic growth in the Asia Pacific region is generally strong. Because growth in energy consumption is principally driven by increases in economic output and income, this positive outlook is likely to contribute to significant growth in energy consumption in the region. This is particularly true for many of the energy intensive and developing

15 Asia Pacific LNG importers



economies in the Asia Pacific region. China, India and Korea are projected to sustain economic growth rates of 5 per cent a year or more over the coming decade, which will fuel strong growth in their energy consumption, particularly of electricity (figure 16). Japan, on the other hand, faces a slower economic and energy outlook, with its economic growth prospects somewhat contingent on its commitment to meaningful economic reform and policies to address its aging population and declining labor force (Hester et al. 2004). With gas being a competitively priced fuel in particular applications, growth in overall energy and electricity consumption should translate into increased consumption of natural gas.

16 **Average annual GDP growth, 2001–15**



Energy market reform

Many economies in the Asia Pacific region are implementing market liberalising reforms in their electricity and gas markets. These reforms generally include privatisation of state owned utilities and the introduction of competition in electricity and gas sectors. Liberalisation in power and gas markets is likely to increase competitive pressures on utilities and provide incentives for cost minimisation, thereby increasing the emphasis on prices and flexibility in fuel procurement activities. In a liberalised market, it is more difficult for utilities to forecast their demand for fuels because they face greater uncertainty about future sales. Utilities are likely, therefore, to be more reluctant to commit to large volumes of fuel supplies under long term contracts. As observed in Japan following partial liberalisation of the gas market, this has implications for future LNG contracts: utilities have been seeking more flexible and shorter LNG contracts in recent procurement activities.

The reform of gas markets and the expected increases in efficiency and competition have the potential to increase the relative competitiveness of natural gas and stimulate new demand. In 2002, ABARE assessed the economic and sectoral impacts of the comprehensive liberalisation of elec-

Box 3: **Gas demand projections using ABARE's global trade and environment model**

Global trade and environment model

The analysis in this chapter of the potential demand for natural gas in the Asia Pacific region over the period to 2015 is based on simulation results from ABARE's global trade and environment model (GTEM). GTEM is a multiregion, multisector, dynamic general equilibrium model of the world economy. It is derived from the MEGABARE model (ABARE 1996) and the GTAP model (Hertel 1997).

GTEM is an appropriate framework for analysing energy markets because it takes into account the interaction between different sectors of the economy and between economies through trade links. The model includes a high level of commodity disaggregation, including a detailed treatment of energy and energy related sectors and a sophisticated representation of technological change and interfuel substitution possibilities in the energy sector. This disaggregation enhances the capacity of GTEM to analyse the impacts of changes in energy policies and other external factors that could influence the operation of energy markets.

Further information on GTEM is available on ABARE's website, www.abareconomics.com.

Regional and sectoral aggregation

At its most disaggregated level, the version of GTEM used in this study consists of equations and data that describe the production, consumption, trade and investment behavior of representative producers and consumers in 68 regions across 56 sectors. The database used to simulate the potential demand for natural gas in the Asia Pacific region in this report has been aggregated to the 21 regions and 15 sectors presented in the following table.

The sectoral aggregation was chosen to include the three fossil fuels — coal, oil and gas — and electricity, and the major energy intensive industries that are likely to influence energy consumption. The regional aggregation identifies major gas consuming, producing and trading regions in the Asia Pacific market.

Developing a reference case

As a dynamic general equilibrium model, GTEM requires a reference case or 'business as usual' simulation against which the impacts of alternative policies can be measured. The reference case projects the growth in key variables in a region, including economic activity and energy demand, in the absence of any significant policy changes or external shocks.

continued

Box 3: **Gas demand projections using ABARE's global trade and environment model** *continued*

Regions		Sectors	
1	Australia	1	Coal
2	New Zealand	2	Oil
3	Canada	3	Gas
4	United states	4	Petroleum products
5	Japan	5	Electricity
6	Western Europe	6	Iron and steel
7	Russian Federation	7	Aluminium
8	Mexico	8	Nonferrous metals
9	Central America	9	Chemicals, rubber and plastics
10	China	10	Nonmetallic mineral products
11	Chinese Taipei	11	Other mineral products
12	Republic of Korea	12	Other manufacturing
13	Indonesia	13	Trade and transport
14	Malaysia	14	Agriculture, fisheries and forestry
15	The Philippines	15	Services
16	Rest of ASEAN **a**		
17	India		
18	Middle East		
19	North Africa		
20	Sub Saharan Africa		
21	Rest of world		

a Singapore, Thailand and Viet Nam.

The development of the reference case requires a number of key assumptions to be made, including assumptions of economic growth and the fuel mix in electricity generation. Gross domestic product (GDP) growth rate assumptions are made for each region identified in the aggregation. The historical growth rates used in the study to 2003 are from the International Monetary Fund. Long term projections to 2015 are from ABARE and are derived by fitting an ARIMA (autoregressive integrated moving average) forecasting model to the historical GDP data. The GDP growth rate assumptions for individual countries in the Asia Pacific region are presented in each profile in this chapter.

Also incorporated in the reference case are assumptions relating to the fuel shares in electricity generation. In GTEM, electricity production is modeled using a 'technology bundle' approach. Under this approach, electricity is generated by a finite number of technologies, or fuels, with distinct fixed input requirements. The power generation technologies in the model are coal, oil, gas, nuclear, hydropower and other renewables. The share of each fuel in total electricity generation is determined exogenously (outside the model) in the reference case, using government and other projections. Again, the electricity generation shares for individual countries are presented in each profile in this chapter.

tricity, gas and downstream petroleum sectors in Asia Pacific Economic Cooperation (APEC) member economies by the end of the decade (Fairhead et al. 2002). In that study, natural gas across APEC was most advantaged by the removal of structural and regulatory barriers to competition in energy markets, with gas consumption in all APEC economies projected to be 5 per cent higher in 2010 than it would have been in the absence of reform. The effects were greater in some individual economies, including China, Chinese Taipei and Japan. The significant increase in gas use was driven primarily by the enhanced competitiveness of gas as a fuel for power generation relative to coal and oil — sectors in which the scope for productivity driven price reductions is more limited. The most substantial increases in gas consumption were in economies that were furthest from competitive energy markets at the beginning of the period and in which gas already played an important role.

Energy security

Many Asia Pacific economies have few indigenous energy sources and rely significantly on energy imports to meet energy requirements. With strong growth expected in energy consumption in these countries, energy imports in the region are likely to continue to rise. Reflecting this, many countries in the region have policies aimed at enhancing energy security. These policies include goals to diversify both the type of fuels used and the geographic distribution of energy imports, including reducing reliance on oil imports from the Middle East.

In Japan, Korea and Chinese Taipei, energy security policies contributed to the introduction of LNG. Ongoing emphasis on energy security and increasing the use of natural gas is reflected in recent policies in each country, and is likely to encourage growth in gas demand over the outlook period.

Nuclear power issues

All three established Asia Pacific LNG markets developed nuclear power as a key focus of their electricity sectors, primarily to enhance energy security. However, growing safety and environmental concerns and public opposition are contributing to a re-evaluation of nuclear power projects in each country. In Japan, public concerns over nuclear power have constrained the development of nuclear generation capacity over the past decade. These concerns relate to the safety of nuclear power (following a number of minor incidents) and to environmental issues surrounding the disposal of spent nuclear fuel. Public acceptance of nuclear power has been further eroded since August 2002 when the Tokyo Electric Power Company shut down its nuclear reactors for detailed safety inspections (EIA 2003c). Similar public resistance has affected the development of nuclear projects in Korea, while progress on the construction of Chinese Taipei's fourth nuclear power plant has also been delayed as a result of local, environmental and political opposition. There is also discussion underway in Chinese Taipei to promote a non-nuclear homeland and the possible early decommissioning of existing nuclear plants.

Nuclear and gas fired power generation typically cater for different load characteristics, so changes to nuclear energy policy can be expected to affect LNG demand only at the margin over the long term. However, gas fired electricity generation units are frequently used to provide intermediate load power, and these units could probably run as base load in the short to medium term if required. The substitution of gas fired power generation for nuclear power was evident in Japan in 2003 and in Korea in early 2004. The recent short term closure of two nuclear plants in Korea in response to a radiation leak and the need for maintenance, for example, required the import of additional LNG cargoes to meet the increased demand for gas fired electricity (FACTS Inc. 2004a).

Environmental policies

The environment and sustainable development, particularly in relation to energy use, are emerging as some of the most important issues facing many Asia Pacific economies. Natural gas, with its relatively clean and efficient properties, is a key fuel in this context. Many countries in the region have developed policies that encourage substitution away from conventional fossil fuels such as coal and petroleum, toward relatively clean fuels, including natural gas and renewable energy.

In India and China, soaring energy use, combined with the high share of coal in the energy mix, have contributed to severe air and water pollution. Both countries are promoting and investigating the use of natural gas to help address these issues. China, for example, has prohibited the construction and expansion of coal fired power plants in some large and medium sized cities. Korea has also prohibited the construction of thermal power plants that use fuels other than natural gas in the Seoul metropolitan area.

Of the countries considered in this study, Japan and New Zealand have ratified the Kyoto Protocol and have committed to potentially binding greenhouse gas emission reduction targets over the next decade. The Japanese government has indicated that it will promote the use of less emission intensive energy sources such as natural gas, renewables and nuclear power as the principal means of achieving its target (Hester et al. 2004). Policies designed to reduce greenhouse gas emissions can have a positive effect on natural gas demand growth, particularly if these involve measures that increase the relative cost of more carbon intensive energy sources such as coal. On the other hand, progress on clean coal technologies could provide an environmentally acceptable and competitive alternative to gas (Wybrew-Bond and Stern 2002).

Gas infrastructure and investment

The development of natural gas infrastructure, including domestic and international pipelines, gas fired power plants and LNG receiving terminals, will be an important factor driving future gas demand. In Korea, the development of a domestic gas pipeline system that covers much of the country has been largely responsible for the rapid growth in gas consumption over the past decade and has enabled the widespread uptake of natural gas by residential, commercial and industrial users (Ball et al. 2003). In Japan, the lack of a national pipeline system has limited the penetration of natural gas outside the electricity sector, and is likely to continue to do so in the near term.

India, China and the Philippines are currently undertaking substantial expansions in their natural gas infrastructure. However, developing infrastructure to deliver gas by pipeline and/or LNG to these markets will be highly capital intensive and will require the mobilisation of major investment funds, including foreign investment. Generating investor confidence and securing adequate capital funding can be facilitated by a range of institutional factors that play a critical role in ensuring the effective operation of markets. Key factors that are relevant to gas market development are the pricing mechanism, the regulatory and legal framework, and the rules governing foreign direct investment (Schneider et al. 2003).

Gas pricing

A fundamental principle for developing a well functioning gas market is to have consumers face prices that accurately reflect the costs of supply, and to have suppliers face prices that tell them how consumers value their products. In the emerging gas markets of India and China, large scale expansion in gas demand and supply is likely to be achieved only if gas is priced appropriately. In India, the price of gas supplied by state companies to customers is highly subsidised, which makes it difficult for alternative gas suppliers to compete. The removal of subsidies could allow private companies in India, as well as LNG and pipeline gas importers, to compete with existing gas supply sources, thereby enabling an expansion in gas supply to the market. This could allow further growth in gas consumption, although the impact of such price increases on gas demand could be negative for some time (Wybrew-Bond and Stern 2002).

In China, natural gas pricing varies considerably across categories of end users and regions. Regulated government prices at the wellhead and to large end users are considered too low to give adequate incentives to natural gas producers. In contrast, gas prices in the residential sector and the power sector are considered too high to encourage large scale market expansion (Wybrew-Bond and Stern 2002). This inability of China's consumers to meet high gas prices was reflected in the recent difficulties in securing markets for gas from the west to east pipeline, which led the government to reduce prices to some end users to encourage uptake.

Japan

Japan is the world's largest LNG importer and accounted for almost half of world LNG trade in 2003. As the first Asian country to introduce LNG to diversify its energy mix, Japan provided a model for others in the region to follow and was the stimulus for many regional LNG supply projects. Japan's LNG imports have risen recently as a result of ongoing nuclear power capacity closures.

However, the outlook for growth in gas demand over the next decade remains low. Potential growth in gas consumption, driven by policies that emphasise energy security and cleaner energy sources, will be partly offset by slow economic growth prospects and the absence of a national pipeline network to enable increased gas penetration outside the power sector. LNG imports will continue to meet most of Japan's gas requirements in the short to medium term. There is unlikely to be sufficient new demand during this period to absorb the volumes required for a natural gas pipeline from the Russian Federation, although one could materialise in the longer term.

Economic overview

After three decades of rapid growth, Japan's economy stalled in 1992 following a sharp reduction in inflated asset values (table 6). Since then the economy has stagnated, with GDP growing at an average annual rate of 1.1 per cent. Japan has shown signs of economic recovery on several occasions, usually spurred by a significant increase in exports, only to fall back into sluggish economic activity mainly as a result of weak consumer spending.

Japan's economy recovered in 2003 to grow by around 2.5 per cent, compared with a contraction of 0.3 per cent in 2002. The major contributors to this growth were strong exports, particularly to Asia, and a rebound in investment and consumer spending. The relatively strong rate of growth should be sustained in 2004, with GDP forecast to rise by 4.0 per cent (Penm 2004; Penm and Fisher 2004).

Energy consumption

Driven largely by economic growth, total primary energy consumption in Japan increased at an average annual rate of 1.8 per cent over the past two decades. Total primary energy consumption was 522 million tonnes of oil equivalent in 2000, but has since fallen to 517 million tonnes of oil equivalent in 2002, reflecting the slow down in the economy and Japan's declining energy intensity.

6 Key economic indicators, Japan

						Annual growth		
		1980	1990	2000	2002	1980–90	1990–2000	2000–02
						%	%	%
Real GDP (1995 prices)	US$b	3 298	4 925	5 684	5 715	4.1	1.4	0.3
Population	million	116.8	123.5	126.9	127.4	0.6	0.3	0.2
Energy consumption	Mtoe	346.5	445.9	521.6	516.9	2.6	1.6	–0.5
Energy intensity	toe/US$'000	0.11	0.09	0.09	0.09	–1.5	0.1	–0.7
Energy consumption per person	toe	2.97	3.61	4.11	4.06	2.0	1.3	–0.6

Source: IEA (2004a).

7 Total primary energy consumption, Japan

	1980		1990		2000		2002	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Coal	59.6	17.2	77.8	17.4	91.0	17.4	100.0	19.3
Oil	235.7	68.0	254.8	57.1	262.6	50.3	255.5	49.4
Natural gas	21.4	6.2	44.3	9.9	65.5	12.6	66.4	12.8
Nuclear	21.5	6.2	52.7	11.8	83.9	16.1	76.9	14.9
Renewables	8.4	2.4	16.4	3.7	18.5	3.6	18.1	3.5
Total	346.5	100.0	445.9	100.0	521.6	100.0	516.9	100.0

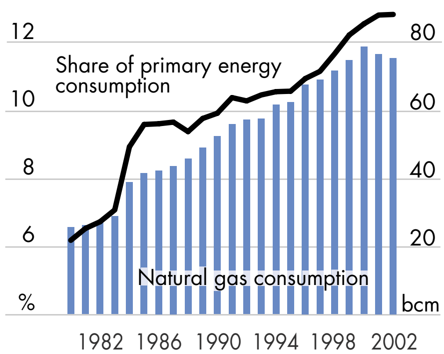
Source: IEA (2004a).

Oil currently accounts for half of total primary energy consumption in Japan, although concerted policies to reduce the country's reliance on oil imports have led to a decline in the share of oil in recent decades (table 7). Coal represented 19 per cent of Japan's primary energy mix in 2002, while nuclear power accounted for a further 15 per cent. The share of natural gas in primary energy consumption was 13 per cent in 2002, considerably lower than the OECD average of 22 per cent.

Natural gas consumption

Concerns about environmental issues and energy security, particularly dependence on oil imports, have led to a steady increase in the role of natural gas in Japan's energy mix over the past two decades. Natural gas consumption has grown by 5.5 per cent a year during that period to reach 75.5 billion cubic metres (equivalent to 55.1 million tonnes of LNG) in 2002, compared with 25.6 billion cubic metres in 1980 (IEA 2003a; figure 17). The fall in consumption since 2000 reflects slower economic growth in Japan and higher LNG import prices during this period.

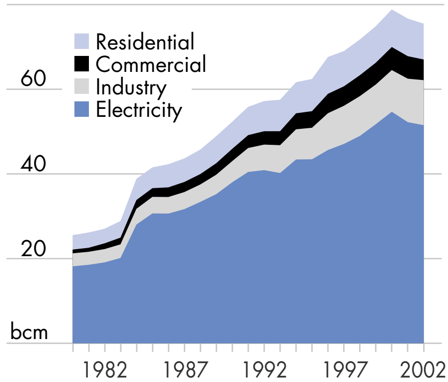
17 Natural gas consumption, Japan



Gas use, by sector

Much of Japan's natural gas consumption has occurred in the electricity sector, which currently constitutes around two thirds of total gas use (IEA 2003a; figure 18). The industry sector accounts for around 13 per cent of natural gas consumption in Japan, while the residential sector consumes a further 12 per cent. The share of each sector has not changed significantly since 1980.

18 Natural gas consumption, by sector, Japan



The share of natural gas in Japan's electricity output has grown from 1 per cent in 1970 to 23 per cent in 2002. The growing use of LNG for electricity generation, mainly as a middle and peak load fuel, is largely a result of Japanese policies aimed at diversification of fuel sources and to reduce air pollution, as well as the technical and economic advantages of natural gas fired power plants. Japan's fuel diversification policies have also significantly increased the number of nuclear and coal fired generators, the other key sources of electricity. As a result, oil fired power has fallen to around 13 per cent of electricity output, compared with more than 46 per cent in 1980 (table 8).

The role of natural gas in other sectors of the economy, including the industry, residential and commercial sectors, remains low, reflecting the absence

8 Electricity generation, by fuel, Japan

	1980		1990		2000		2002	
	TWh	%	TWh	%	TWh	%	TWh	%
Coal	54.9	9.6	123.8	14.6	252.0	23.3	291.1	26.8
Oil	264.7	46.2	254.7	29.9	152.8	14.1	145.3	13.4
Natural gas	81.1	14.2	162.5	19.1	241.3	22.3	244.6	22.5
Nuclear	82.6	14.4	202.3	23.8	322.0	29.8	295.1	27.1
Renewables	89.2	15.6	107.4	12.6	113.8	10.5	111.7	10.3
Total	572.5	100.0	850.7	100.0	1 081.9	100.0	1 087.7	100.0

Source: IEA (2004a).

of a national gas pipeline network. While some pipeline development has occurred in all major urban areas over the past decade, the network covers only around 5 per cent of Japan's land area (Wybrew-Bond and Stern 2002). In addition, many of the existing domestic pipelines are not interlinked, rather, they have been developed by gas and electricity utilities to link areas of demand to specific LNG import terminals. The rate of major pipeline development has been impeded by technical regulation and complex planning approval processes for gas infrastructure which, along with Japan's geographic characteristics, raise the cost of infrastructure construction above that in other countries (IEA 2003c).

Natural gas supply

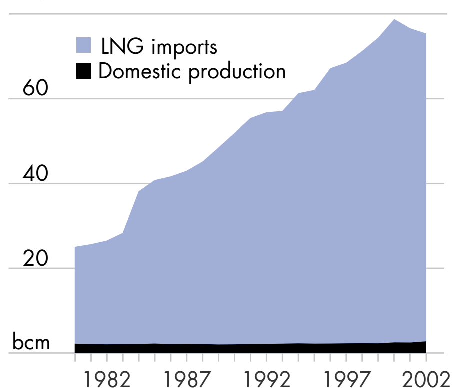
Domestic production

Japan's proven recoverable gas reserves are estimated to be around 39.2 billion cubic metres (equivalent to 28.6 million tonnes of LNG) at the beginning of 2004 (OGJ 2003). Natural gas is produced from fields near Niigata in the northern part of the country and domestic gas production was 2.8 billion cubic metres (equivalent to 2.0 million tonnes of LNG) in 2002. However, this accounted for only 4 per cent of Japan's total gas consumption. Production has been relatively flat in recent years and its share has declined as a proportion of overall gas supply from 9 per cent in 1980 (IEA 2003a; figure 19). At the current rate of production, Japan's gas reserves will be depleted within 16 years (IEA 2003c).

LNG imports

Japan began importing LNG in 1969. Following the two oil price shocks in the 1970s, Japanese imports of LNG increased significantly in order to diversify the energy mix away from oil. LNG imports have grown strongly since that time, by around 5.6 per cent a year between 1980 and 2003. LNG imports reached 58 million tonnes in 2003, compared with 17 million tonnes in 1980 (IEA 2003a; BP 2004).

19 **Gas supply sources, Japan**



The majority of imports are sourced from Indonesia and Malaysia, which collectively account for around half of Japan's LNG supply (table 9). Australia accounted for 13 per cent of total LNG imports in 2003, while Middle Eastern countries accounted for almost 23 per cent. Japan also imported LNG from Trinidad and Tobago for the first time in 2003. This represents a significant diversification of LNG sources compared with two decades ago, when more than 80 per cent of imports were sourced from Indonesia and Brunei (figure 20).

9 LNG imports, by source, Japan, 2003

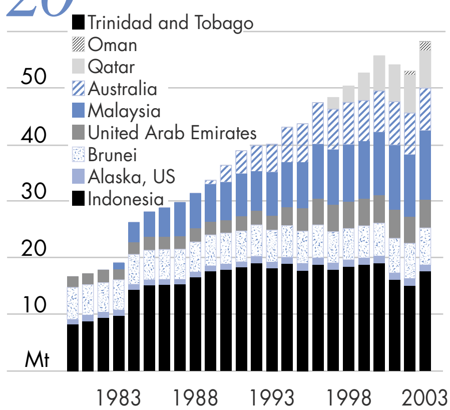
	Mt	%
Indonesia	17.6	30.1
Malaysia	12.2	21.0
Australia	7.5	12.9
Qatar	6.6	11.3
Brunei	6.5	11.2
United Arab Emirates	5.0	8.6
Oman	1.6	2.7
Alaska, US	1.2	2.1
Trinidad and Tobago	0.1	0.1
Total	58.2	100.0

Source: BP (2004).

Japan has one of the world's most diversified gas supply portfolios and currently has long term supply contracts with all eight existing LNG exporters in the Asia Pacific region and the Middle East for around 56 million tonnes a year. Several existing long term contracts are due to expire by the end of the decade, including significant volumes with Australia and Indonesia (table 10). Japanese LNG supply contracts have usually been negotiated in the past by consortiums of electricity and gas utilities. However, with greater competition emerging in Japan's gas distribution market, this trend is beginning to change. Some recent contracts have been negotiated by individual utilities, including the four agreements signed to date with the Russian Federation's Sakhalin 2 project.

The role of spot LNG cargoes in meeting Japan's LNG demand has to date been relatively small and mostly used to manage unexpected changes in demand or disruptions to imports from existing suppliers. For example, spot cargo imports rose in 2003 with the closures of some of Japan's nuclear power generation capacity (box 4).

20 LNG imports, by source, Japan



10 Existing long term LNG supply contracts, Japan a

Source	Project	Importer	Volume	Duration
			Mtpa	
Alaska, US	Kenai	Tokyo Electric Power Company, Tokyo Gas	1.2	1989–2004 **b**
Australia	North West Shelf	Tokyo, Chubu, Kansai, Chugoku and Kyushu Electric Power Companies, Tokyo Gas, Toho Gas, Osaka Gas	7.3	1989–2009
	North West Shelf	Osaka Gas	1.0	2004–21
	North West Shelf	Tokyo Gas, Toho Gas	1.4	2004–29
Brunei	BLNG	Tokyo Electric Power Company, Tokyo Gas, Osaka Gas	6.0	1993–2013
Indonesia	Arun	Tokyo and Tohoku Electric Power Companies	3.5	1984–2004
	Bontang	Chubu, Kansai and Kyushu Electric Power Companies, Toho Gas, Osaka Gas, Nippon Steel	8.5	2000–10
	Bontang	Osaka Gas, Toho Gas	3.5	2003–11
	Bontang	Osaka Gas, Tokyo Gas, Toho Gas	2.0	1994–2013
	Bontang	Osaka Gas, Hiroshima Gas, Nihon Gas	0.4	1996–2015
Malaysia	MLNG I	Saibu Gas	0.4	1993–2013
	MLNG I	Tokyo Gas, Tokyo Electric Power Company	7.4	2003–18
	MLNG II	Tokyo Gas, Osaka Gas, Toho Gas, Kansai Electric Power Company	2.1	1995–2015
	MLNG II	Tohoku Electric Power Company	0.5	1996–2016
	MLNG II	Shizuoka Gas	0.5	1996–2016
	MLNG III	Japex	0.5	2003–23
	MLNG III	Osaka Gas, Toho Gas, Tokyo Gas	1.6	2004–24
Oman	Oman LNG	Osaka Gas	0.7	2000–25
Qatar	Qatargas	Chubu Electric Power Company	4.0	1997–2021
	Qatargas	Tokyo Gas, Osaka Gas	0.7	1998–2021
	Qatargas	Tokyo, Tohoku, Kansai and Chugoku Electric Power Companies	1.1	1999–2021
	Qatargas	Toho Gas	0.2	2000–21
UAE	Das Island	Tokyo Electric Power Company	4.3	1994–2019

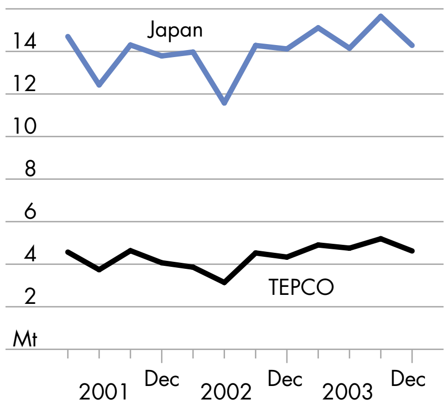
a Does not include some contracts commencing in or after 2005. **b** Option to extend to 2009.
Sources: IEA (2003c); Wybrew-Bond and Stern (2002); Suzuki and Morikawa (2003); Petroleum Economist (2003).

Box 4: **Japan's nuclear power closures and the impacts on LNG**

Reflecting its low cost, low emissions and contribution to energy security, nuclear power has played a key role in Japan's energy system. Nuclear power provided around 31 per cent of Japan's electricity output in 2001 (IEA 2004a). In August 2002, following issues with plant inspection reports, Tokyo Electric Power Company (TEPCO) shutdown several nuclear units for reinspection. To make up for the loss of base load generation, TEPCO initially increased utilisation rates at its existing nuclear plants and started its back up thermal plants, LNG and oil. By March 2003, all of TEPCO's 17 nuclear reactors were closed. This accounted for around 38 per cent of Japan's nuclear capacity. As TEPCO did not have coal fired plants — which would be the usual normal base load substitute for nuclear power — LNG and oil fired plants, normally TEPCO's mid and peak load supply, were used in base load power supply (FACTS Inc. 2003a, 2004a).

TEPCO's nuclear plant closures contributed to a 5 million tonne, or 10 per cent increase in Japanese LNG imports during 2003. Over the same period, TEPCO's LNG purchases rose by 23 per cent, or close to 4 million tonnes (Japan Customs 2004; FEPC 2004; figure 21). Existing long term contracts for LNG were insufficient to meet this rise in demand, and additional LNG was sourced through cargo swaps with Korea's KOGAS and through the purchase of spot market cargoes (EIG 2003a).

21 Quarterly LNG imports, TEPCO and Japan



With many of TEPCO's nuclear plants remaining closed in 2004, LNG imports are likely to continue to be affected, although to a lesser extent as more nuclear plants gradually come back on line. As of July 2004, TEPCO had restarted 12 of its 17 nuclear plants.

While this issue continues to have short term impacts on Japan's LNG imports, it also highlights some uncertainty over the longer term about Japan's future nuclear program. The closures have contributed to already high levels of public concern over nuclear power, including safety and spent fuel disposal issues. These concerns have hampered the development of nuclear facilities over the past decade and are likely to continue to do so. With Japanese policies aiming to balance both energy security and environmental concerns, gas fired power generation could be expected to benefit from any move away from nuclear power.

LNG import infrastructure

There are currently 25 LNG receiving terminals in Japan, most of which are adjacent to and serve individual power plants. Many terminals are located close to the regions where Japan's energy demand is concentrated, along the southern coastline. The large number of terminals reflects the fact that in

11 LNG receiving terminals, Japan

Terminal	Operator	Start up	Capacity
			Mtpa
Existing			
Negishi	Tokyo Gas	1969	13.6
Senboku I	Osaka Gas	1972	2.5
Sodegaura	Tokyo Gas	1973	27.7
Senboku II	Osaka Gas	1977	13.1
Chita Kyodo	Toho Gas	1977	8.0
Tobata	Kitakyushu LNG	1977	6.4
Himeji	Kansai Electric Power Company	1979	8.3
Chita	Chita LNG	1983	12.0
Himeji II	Osaka Gas	1984	4.0
Higashi-Niigata	Nihonkai LNG	1984	17.1
Higashi-Ohgishima	Tokyo Electric Power Company	1984	14.7
Futtsu	Tokyo Electric Power Company	1985	16.0
Yokkaichi LNG Centre	Chubu Electric Power Company	1987	8.8
Shin-Oita	Oita LNG	1990	5.1
Yanai	Chugoku Electric Power Company	1990	2.4
Yokkaichi Works	Toho Gas	1991	0.6
Fukuoka	Saibu Gas	1993	0.6
Hatsukaichi	Hiroshima Gas	1995	0.4
Sodeshi/Shimizu	Shimizu LNG	1996	6.4
Kagoshima	Nippon Gas	1996	0.1
Kawagoe	Chubu Electric Power Company	1997	7.7
Shin-Minato	Sendai City Gas Bureau	1997	8.0
Ohgishima	Tokyo Gas	1998	5.1
Chita-Midorihama	Toho Gas	2001	4.2
Nagasaki	Saibu Gas	2003	0.1
Total			192.9
Under construction			
Mizushima LNG	Chugoku Electric Power Company	2006	0.6
Sakai LNG	Sakai LNG	2006	2.7
Total			3.3

Sources: EIA (2003b); Suzuki and Morikawa (2003); Petroleum Economist (2003).

areas where sustained growth in demand is forecast, the solution to date has been to build additional LNG import terminals close to the area of increasing demand, rather than to extend a gas pipeline from an existing terminal with available capacity (IEA 2003c).

Collectively, the 25 terminals have the capacity to import around 195 million tonnes a year (table 11). This is significantly higher than current annual imports but necessary to provide the flexibility required by utilities to meet seasonal demand peaks. In addition, two LNG receiving terminals are currently under construction and several more are proposed over the coming decade (Suzuki and Morikawa 2003).

Outlook for natural gas demand

Key assumptions for Japan

Japan's economy is expected to recover slowly over the medium term, with GDP assumed to increase at an average annual rate of 1.3 per cent between 2001 and 2015. However, economic growth in Japan could be higher over the outlook period if effective economic reforms are implemented and the issue of Japan's aging population and declining labor force is addressed. In view of this, a scenario assuming Japan's economy expands more rapidly, by an average 1.8 per cent a year between 2001 and 2015, is also presented (box 5).

Japan's fuel mix for electricity generation is expected to remain fairly stable out to 2015. Natural gas will fuel approximately 25 per cent of Japan's power supply in the projection period. Nuclear power and coal are the other major sources of electricity output in Japan, with the share of each assumed to increase marginally between 2002 and 2015 to reach 32 per cent and 24 per cent respectively (table 12).

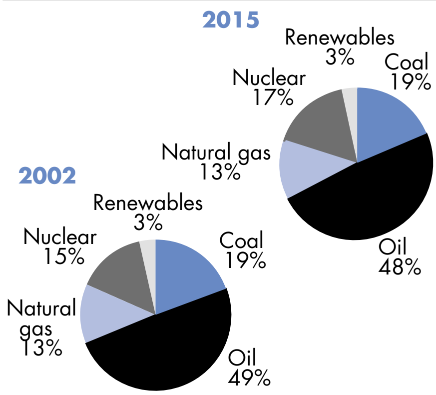
Japan's Ministry of Economy, Trade and Industry (METI) released revised nuclear power generation targets in mid-2004. Japan is expected to have four new nuclear reactors — which are currently under construction — by 2010 and a further six by 2030. This target reflects the expected slow

12 Assumed fuel mix in electricity generation, Japan

	2002	2010	2015
	%	%	%
Coal	26.8	23.3	24.0
Oil	13.4	10.2	9.5
Natural gas	22.5	24.9	24.8
Nuclear	27.1	31.9	32.2
Renewables	10.3	9.7	9.5
Total	100.0	100.0	100.0

growth in Japan's electricity consumption and public resistance to new nuclear plants (Hester et al. 2004). The assumptions for nuclear power generation used in this study are consistent with the METI targets.

22 **Primary energy consumption, by fuel, Japan**



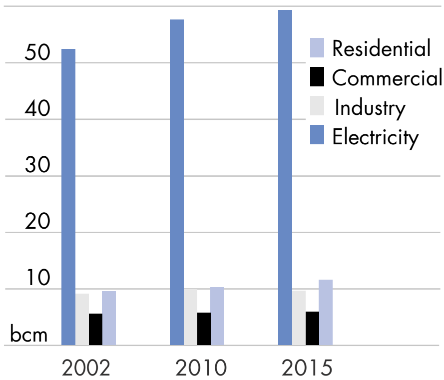
Natural gas demand projections

Primary energy consumption in Japan is projected to grow by 0.8 per cent a year over the outlook period to reach 578 million tonnes of oil equivalent in 2015, compared with 521 million tonnes of oil equivalent in 2001. Japan's aging population is expected to moderate growth in energy consumption in the latter part of the outlook period, as rising labor costs begin to undermine the competitiveness of Japanese industry.

Natural gas is projected to be the fastest growing fossil fuel in Japan over the coming decade. Gas consumption is projected to expand at an average annual rate of 0.8 per cent, rising from 77 billion cubic metres in 2001 to 87 billion cubic metres (equivalent to 63 million tonnes of LNG) in 2015. Despite the growth, little change is anticipated in the share of gas in Japan's total primary energy consumption, remaining at around 13 per cent in 2015 (figure 22).

Gas consumption in Japan over the next decade will continue to be concentrated in the power sector (figure 23). It is projected that gas consumption in the electricity sector will rise at an average annual rate of 0.8 per cent in the period 2001–15. Growth may be higher if the contribution of nuclear power generation over the outlook period is lower than forecast, or if the government's policy of encouraging electricity suppliers to use natural gas proves effective. In

23 **Projected natural gas consumption, by sector, Japan**



2002, for example, METI introduced a program to encourage electricity utilities with older coal fired boilers to switch to natural gas. Under this program METI will provide a 10 per cent subsidy of the associated costs if companies reconstruct eligible plants to use natural gas with a thermal efficiency of at least 48 per cent.

Some growth in gas consumption is also expected to occur in the commercial and residential sectors, underpinned by an ongoing structural shift in Japan's economic output toward services and rising household energy use. The potential for growth in these sectors over the outlook period is constrained by the limited national gas pipeline network in Japan.

Box 5: **Higher GDP growth scenario — implications for Japanese LNG demand**

Japan's economy has recently been growing relatively strongly, recording a 4.5 per cent increase in GDP in the Japanese fiscal year ending March 2004 (JCER 2004). The resurgence in economic growth is being driven predominantly by strong growth in Japan's export markets, principally China and the United States. While there have been some signs of improvement in Japan's demand economy, consumer demand and investment spending remain impeded by structural rigidities (IMF 2004; Hubbard 2003). In order to sustain stronger growth in the longer term, Japan will need to implement effective structural reforms to drive growth in internal demand.

While Japan has made progress in reforming its commercial sector, economic growth is constrained by structural inefficiencies in other sectors of the economy. An important example is Japan's banking sector, which has been burdened by a large proportion of non-performing loans since the early 1990s. The persistence of non-performing loans has allowed inefficient, loss-making firms to remain operating, repressing the creation and growth of efficient businesses in those sectors that depend on banking finance (OECD 2004). Compounding the weakness of Japan's financial sector is deflation, which has persisted since the mid-1990s. Deflation creates incentives that undermine economic growth: in particular by deterring investment by reducing real returns. At the same time, consumers tend to defer purchases, thereby undermining domestic demand.

continued

Box 5: **Higher GDP growth scenario — implications for Japanese LNG demand** *continued*

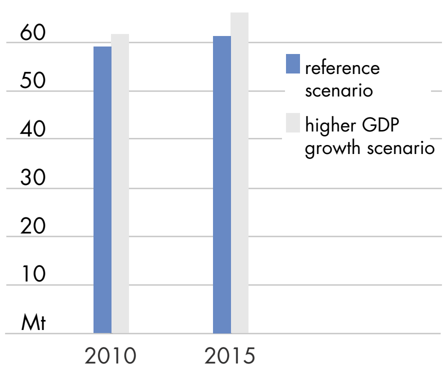
The aging of Japan's population also poses a serious threat to Japan's economic growth beyond 2005. Japan's working aged population has been in decline since 1995 and the decline is likely to accelerate in the near future. Without an effective policy response, this will translate into a decline in Japan's productive capacity and a rise in Japan's public spending.

The effective addressing of these issues is expected to translate into higher economic growth in Japan. GTEM is used to quantify the implications of higher economic growth for gas demand, and LNG imports in particular. In the higher economic growth scenario, it is assumed Japan's GDP grows at an average rate of 1.8 per cent a year between 2001 and 2015, compared with 1.3 per cent a year in the standard case. This higher growth is achieved by implementing economic reforms, along with labor sector initiatives to defer the decline in Japan's effective work force, for example by reducing under-employment among young adults and by raising the participation rates of adults aged over 60 years.

In the higher GDP growth scenario, it is projected that Japan's total primary energy consumption increases at an average an annual rate of 1.3 per cent over the outlook period to reach 624 million tonnes of oil equivalent in 2015. This is around 46 million tonnes of oil equivalent greater than in the absence of higher economic growth in Japan.

Gas consumption and LNG imports are projected to be higher in the higher GDP growth scenario. LNG imports are projected to rise by 1.4 per cent a year to reach 66.0 million tonnes in 2015 when economic growth is higher in Japan (figure 24). This represents 4.6 million tonnes of imported LNG at 2015 additional to that in the standard growth case.

24 LNG imports under a higher GDP growth scenario, Japan



Natural gas demand and supply balance

As discussed earlier, domestic natural gas production in Japan has remained relatively flat over the past two decades. Reflecting this, it is assumed that annual domestic production remains at its current level of equivalent to 1.8 million tonnes out to 2015. The remainder of gas consumption in Japan is expected to be met by imports. Japan's natural gas imports are projected to rise over the outlook period to reach 61.4 million tonnes by 2015 (table 13). It is expected that all of Japan's gas imports out to 2015 will continue to be met by LNG.

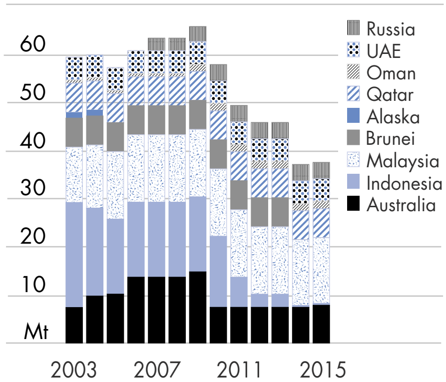
13 Projected natural gas demand and supply, Japan

	2010	2015
	Mt	Mt
Projected natural gas demand	61.1	63.2
Projected domestic supply	1.8	1.8
Projected LNG imports	59.3	61.4
Existing LNG supply contracts	57.6	37.3
Projected uncontracted gas demand	1.7	24.0

Japan's existing long term LNG supply contracts are expected to be sufficient to meet import demand until the end of this decade. However, a number of large contracts are due to expire around that time. These include 7.3 million tonnes of LNG a year from Australia's North West Shelf in 2009, and close to 12 million tonnes a year from Indonesia's Bontang in 2010-11 (figure 25). To date, only one of these contracts has been renewed: Kansai Electric Power Company and North West Shelf Australia LNG have contracted 0.5 million tonnes a year from 2009, rising to 0.93 million tonnes a year between 2015 and 2023.

Based on known long term LNG contracts, Japan's contracted supply of LNG at 2010 will be 57.6 million tonnes. This includes the four agreements signed to date between Japanese utilities and the Russian Federation's Sakhalin 2 project for 3.4 million tonnes a year, and the recent 0.8 million tonnes a year from Oman LNG to Osaka Gas. This leaves Japan with uncontracted LNG demand of 1.7 million tonnes in that year. With

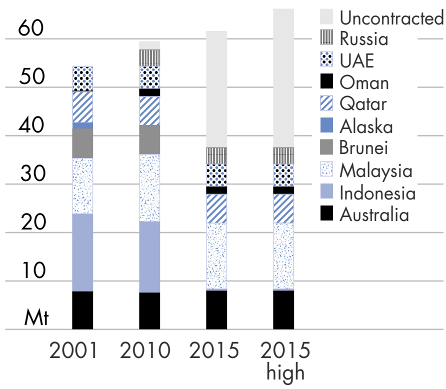
25 Existing long term LNG supply contracts, Japan



the expiry of further LNG contracts and growth in gas demand, the shortfall between demand and currently contracted supply is expected to rise strongly between 2010–15, to 24 million tonnes in 2015 (figure 26).

It should be noted that this figure assumes no renewals of existing long term contracts, other than those already announced. In addition, the actual volume of LNG supplied in a particular year could vary from that shown here, as several of Japan's recently signed contracts are reported to have greater offtake flexibility and slower build up periods.

26 **Projected LNG imports, Japan**



Future gas supply options

Given there is likely to be uncontracted gas demand by the end of the decade, an important issue for Japan is how this demand will be met. Many of Japan's existing long term LNG contracts have optional extension clauses, and extensions of such contracts would contribute significantly to meeting the shortfall between projected demand and existing LNG supplies over the outlook period. It is not certain, however, what proportion of long term LNG contracts will be renewed and it is expected that at least some will be contestable. In view of this, new LNG contracts are also expected to play a key role in meeting Japan's gas import demand in period to 2015.

An additional gas import option for Japan over the longer term is a pipeline from the Russian Federation. There are currently provisions for the introduction of a Russian pipeline in Japan's Basic Energy Plan, in order to strengthen energy security by diversifying supply sources and energy types. The most likely gas pipeline option for Japan is a pipeline from Sakhalin Island in the far east. In 2002, the Japan Sakhalin Pipeline Company completed a feasibility study on a Sakhalin pipeline to Japan and announced the technical and commercial feasibility of a pipeline to supply natural gas equivalent to 6 million tonnes of LNG (Suzuki and Morikawa 2003; IEA 2003c). The targeted start up date for the Sakhalin pipeline is 2008.

However, given the complex issues to resolve in building transborder pipelines and the pace of negotiations to date, a gas pipeline between Japan and the Russian Federation is unlikely to materialise this decade. Further, the additional gas demand coming on line in Japan is not likely to be sufficient to justify a large international pipeline until at least the following decade. It is also considered that Japan would need a more extensive domestic gas pipeline network for a large international pipeline to proceed, in order to link existing and potential new consumers to create the necessary aggregated demand (IEA 2003c). In light of these issues, LNG is expected to remain the only source of gas imports to Japan in the period to 2015.

Republic of Korea

Natural gas has played an increasingly important role in meeting Korea's rapidly growing energy demand since the introduction of LNG to the market in the mid 1980s. This trend is likely to continue, with strong growth in natural gas consumption forecast over the next decade. With limited domestic reserves, Korea has relied exclusively on imports of LNG to meet its natural gas requirements, although small scale domestic production commenced in 2004. Korea is now the world's second largest importer of LNG after Japan. LNG will continue to meet the majority of Korea's projected gas consumption, although over the longer term, pipeline natural gas imports from the Russian Federation could provide a complementary source of gas supply.

Korea presently has among the largest uncommitted demand in the region over the outlook period. Until recently, the Korean government had delayed signing new long term LNG contracts until issues surrounding gas market reform were resolved. However, in view of concerns about gas supply security and the potential significant gap between gas demand and contracted supply in the next few years, LNG procurement has been delinked from reform and KOGAS is currently seeking new long term contracts.

Economic overview

The Korean economy has grown rapidly over the past two decades, at an average annual rate of 7.1 per cent since 1980 (table 14). Economic growth fell sharply in 1998 as a result of the Asian financial downturn but recovered quickly to reach 6.3 per cent in 2002, reflecting robust domestic consumer spending and growth in export sectors. Growth in 2003, however,

14 Key economic indicators, Korea

		1980	1990	2000	2002	Annual growth 1980–90	1990–2000	2000–02
						%	%	%
Real GDP (1995 prices)	US$b	149.1	341.6	620.4	680.3	8.6	6.2	4.7
Population	million	38.1	42.9	47.0	47.6	1.2	0.9	0.7
Energy consumption	Mtoe	43.9	93.2	192.9	208.6	7.8	7.5	4.0
Energy intensity	toe/US$'000	0.29	0.27	0.31	0.31	–0.8	1.3	–0.7
Energy consumption per person	toe	1.15	2.17	4.10	4.38	6.6	6.6	3.3

Sources: KEEI (2003); KNSO (2003).

slowed to 3.1 per cent as a result of weak consumer spending and slower growth in the world economy, particularly demand for Korean exports in the United States. In 2004, GDP growth is forecast to rise to 5.0 per cent in response to stronger world economic growth and exports (Penm 2004).

Energy consumption

Energy consumption in Korea has increased by more than 7 per cent a year over the past two decades, driven by rapid growth in economic output — particularly in energy intensive industries such as petrochemicals, steel and shipbuilding — and rising personal incomes. Total primary energy

15 Total primary energy consumption, Korea

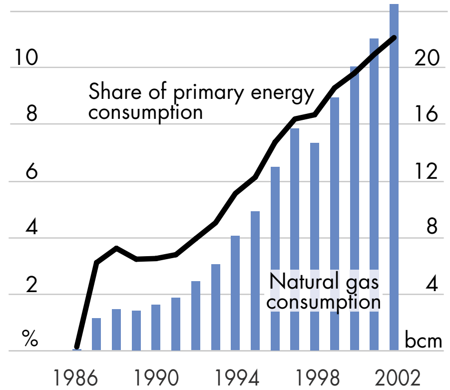
	1980		1990		2000		2002	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Coal	13.2	30.1	24.4	26.2	42.9	22.2	49.1	23.5
Oil	26.8	61.1	50.2	53.8	100.3	52.0	102.4	49.1
Natural gas	–	–	3.0	3.2	18.9	9.8	23.1	11.1
Nuclear	0.9	2.0	13.2	14.2	27.2	14.1	29.8	14.3
Renewables	3.0	6.9	2.4	2.6	3.5	1.8	4.3	2.0
Total	43.9	100.0	93.2	100.0	192.9	100.0	208.6	100.0

Source: KEEI (2003).

consumption in 2002 was 209 million tonnes of oil equivalent, compared with 44 million tonnes of oil equivalent in 1980 (table 15).

Oil is the main source of energy in Korea, accounting for 49 per cent of total primary energy consumption in 2002, although its share has declined in recent years. Coal is also an important energy source in Korea, representing 23 per cent of primary energy consumption. Natural gas has increased its share of Korea's energy mix over the past decade. It accounted for 11 per cent of primary energy consumption in 2002, compared with 3 per cent in 1990.

27 **Natural gas consumption, Korea**



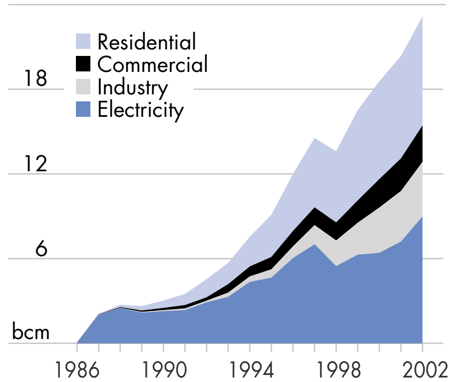
Natural gas consumption

Natural gas, in the form of imported LNG, was introduced into the Korean market in 1986, and has grown rapidly since that time. Gas consumption has increased at an average annual rate of 19 per cent since 1990, and in 2002, natural gas consumption was 24.5 billion cubic metres (equivalent to 17.9 million tonnes of LNG) (KEEI 2003; figure 27). The rapid growth has been a result of government policies to encourage natural gas use, expansion in gas infrastructure, including gas distribution networks and gas fired electricity plants, and rising personal incomes that have induced a shift in preferences to clean and efficient fuels (Ball et al. 2003).

Gas use, by sector

Unlike Japan, the main source of the sharp rise in natural gas demand in Korea over the past decade has been rapid growth in

28 **Natural gas consumption, by sector, Korea**



16 Electricity generation, by fuel, Korea

	1980		1990		2000		2002	
	TWh	%	TWh	%	TWh	%	TWh	%
Coal	2.5	6.7	20.0	18.5	97.5	36.6	118.0	38.5
Oil	29.3	78.7	18.9	17.5	26.1	9.8	25.1	8.2
Natural gas	–	–	9.6	8.9	28.1	10.6	38.9	12.7
Nuclear	3.5	9.3	52.9	49.1	109.0	40.9	119.1	38.9
Renewables	2.0	5.3	6.4	5.9	5.6	2.1	5.3	1.7
Total	37.2	100.0	107.7	100.0	266.4	100.0	306.5	100.0

Source: KEEI (2003).

gas consumption in the residential and industry sectors (IEA 2003a; figure 28). The residential sector, driven by strong demand for heating and, increasingly, space cooling, accounted for one third of total natural gas use in Korea in 2002. The industry sector accounted for 17 per cent of natural gas consumption, with the main gas using industries being the iron and steel sector, and to a lesser extent, the chemicals and petrochemicals sector. The penetration of gas in these sectors was underpinned by Korea's extensive domestic gas pipeline network, covering much of the country.

Electricity generation comprised around 39 per cent of natural gas consumption in Korea in 2002. Gas accounted for 13 per cent of Korea's power generation in that year and is used primarily as a peak load fuel (table 16). Coal and nuclear power are the main sources of power generation in Korea, each accounting for around 40 per cent of electricity output. The changing fuel shares over the past two decades reflect Korean energy policies, which have emphasised the use of natural gas, coal and nuclear energy in an effort to stabilise energy supply (MOCIE 2004).

Natural gas supply

Domestic production

Korea's only known gas reserves are in the Donghae field in the East Sea. Recoverable reserves in that field are estimated at around 6 billion cubic metres (equivalent to 4 million tonnes of LNG). Gas production from this field commenced in July 2004 (KEEI 2004). The Donghae 1 project is expected to deliver around 0.6 billion cubic metres of natural gas (equivalent to 0.4 million tonnes of LNG) a year, or approximately 2 per cent of Korea's current gas demand.

LNG imports

Until recently, all natural gas demand in Korea has been met by imported LNG. Korea is the world's second largest importer of LNG after Japan, importing 19.1 million tonnes in 2003. Around 30 per cent of imports were from Qatar, closely followed by Indonesia (26 per cent) and Oman (25 per cent) (table 17). Australia has played a relatively small role in supplying LNG to Korea, however, its share is expected to increase from 2004 as exports under its mid term contract reach the full volume of 0.5 million tonnes a year.

17 LNG imports, by source, Korea, 2003

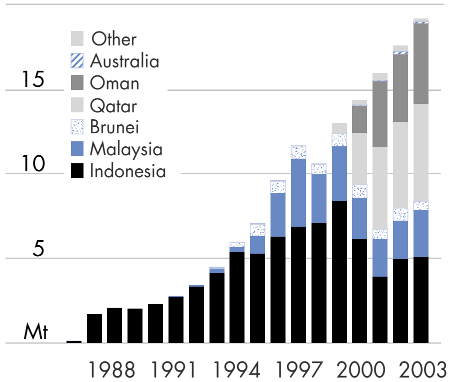
	Mt	%
Qatar	5.75	30.0
Indonesia	5.06	26.4
Oman	4.74	24.7
Malaysia	2.77	14.4
Brunei	0.54	2.8
Algeria	0.17	0.9
Australia	0.12	0.6
Total	19.15	100.0

Source: BP (2004).

Korea's sources of LNG have diversified in recent years, including an increasing reliance on Middle Eastern LNG (KEEI 2003; BP 2004; figure 29). This reflects government policy to diversify supply channels. The majority of Korea's LNG imports are via long term take or pay contracts with Indonesia, Qatar, Oman, Malaysia and Brunei (table 18). Korea currently has long term contracts for 16.7 million tonnes of LNG.

In recent years, the Korean government has delayed signing new long term LNG supply contracts until issues surrounding reform of the gas market were resolved. In the interim, Korea signed two mid term contracts with Malaysia and Australia for up to 2.5 million tonnes a year to the end of the decade. Korea has also used the spot market and short term contracts extensively to meet winter demand peaks and any shortfalls in contracted supply.

29 LNG imports, by source, Korea



18 Existing mid/long term LNG supply contracts, Korea

Source	Project name	Importer	Volume	Duration
			Mtpa	
Long term				
Indonesia	Arun	KOGAS	2.3	1986–2007
Indonesia	Bontang	KOGAS	2.0	1994–2014
Indonesia	Bontang	KOGAS	1.0	1998–2017
Malaysia	MLNG II	KOGAS	2.0	1995–2015
Brunei	BLNG	KOGAS	0.7	1997–2013
Qatar	RasGas	KOGAS	4.8	1999–2024
Oman	OLNG	KOGAS	4.1	2000–24
Total			16.7	
Mid term				
Malaysia	MLNG III	KOGAS	1.5 **a**	2003–10
Australia	North West Shelf	KOGAS	0.5	2003–10
Total			2.0	

a The contract includes an option for an additional 0.5 million tonnes.
Source: KOGAS (2003).

However, in view of the growing shortfall between gas demand and contracted LNG supply and concerns regarding gas supply security, LNG procurement has been delinked from the reform process. In August 2004, KOGAS announced it is seeking three long term supply contracts for a total volume of between 4.5 and 6.0 million tonnes a year from 2008.

19 LNG receiving terminals, Korea

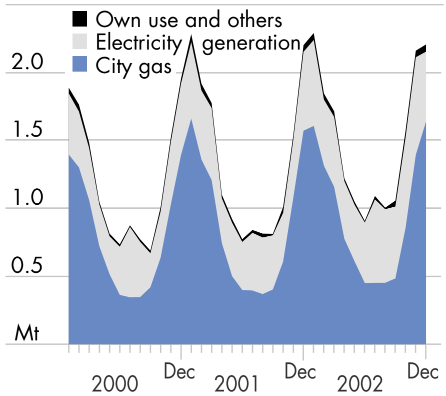
Terminal	Operator	Start up	Capacity	Imports 2002
			Mtpa	Mt
Existing				
Pyeongtaek	KOGAS	1986	13.3	9.1
Incheon	KOGAS	1996	22.4	6.5
Tongyeong	KOGAS	2002	5.0	1.2
Total			40.7	17.8
Under construction				
Kwangyang	POSCO	2005	1.7	–

Sources: KOGAS (2003); EIA (2003b).

LNG import infrastructure

Korea currently has three LNG receiving terminals at Pyeongtaek, Incheon and Tongyeong (table 19). These terminals are owned and operated by KOGAS, Korea's gas importing and wholesale monopoly. POSCO, Korea's largest steel producer, has commenced construction of an LNG receiving terminal at Kwangyang, which is expected to be in operation in early 2005. This will be the first privately owned terminal in Korea. POSCO and SK Power are scheduled to begin importing around 1.1 million tonnes of LNG a year from Indonesia for their own use from 2005 and 2006 respectively.

30 Monthly LNG consumption, by sector, Korea



Korea currently has an annual import capacity of around 41 million tonnes of LNG. This is significantly greater than current import volumes, however, it provides Korea with much needed flexibility in the timing and storage of its imports. LNG consumption in Korea exhibits strong seasonal fluctuations. LNG use in the peak winter months (December–February) generally averages at least twice that in summer (Ball et al. 2003; figure 30). Most of this seasonal variation is explained by the high proportion of gas use in the residential sector, contributing to high heating loads in the winter.

Outlook for natural gas demand

Key assumptions for Korea

GDP in Korea is assumed to grow at an average annual rate of 5.0 per cent between 2002 and 2015. However, growth prospects for Korea in the medium term will remain dependent on the strength of the world economy, particularly that of the United States.

In Korea there is some uncertainty surrounding the role that natural gas may play in electricity generation over the period to 2015. The current government Basic Plan of Long Term Electricity Supply and Demand indicates a sharp decline in the share of gas fired power generation toward the end of the decade in response to planned expansions in nuclear and coal fired capacity (MOCIE 2002). Because of uncertainty surrounding future nuclear developments, environmental concerns over coal fired power generation, and the relative competitiveness of gas fired power generation, it is generally believed that such a sharp projected decline in gas fired output is unlikely to be realised (Ball et al. 2003).

20 Assumed fuel mix in electricity generation, Korea

	2002	2010	2015
	%	%	%
Coal	38.5	44.3	37.8
Oil	8.2	4.5	2.8
Natural gas	12.7	6.7	11.2
Nuclear	38.9	42.1	46.1
Renewables	1.7	2.5	2.1
Total	100.0	100.0	100.0

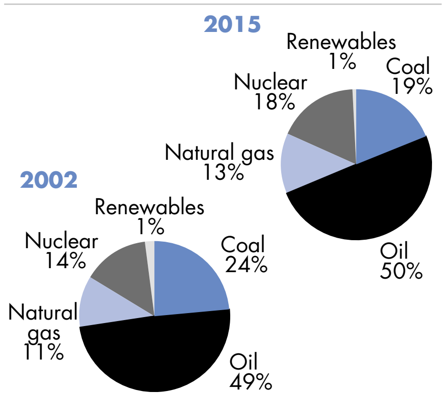
In light of this, projections by the Korea Power Exchange that assume a smaller decline in gas use are used (KPX 2002). The share of gas in total electricity output is assumed to rise initially in outlook period but to fall from 2007–10 as a result of strong expansion in nuclear and coal fired output. From 2010, the share of gas fired output is assumed to rise again from 7 per cent to 11 per cent in 2015, slightly below current levels (table 20).

Natural gas demand projections

Underpinned by significant increases in economic output, energy consumption in Korea is projected to grow at 3.5 per cent a year over the outlook period to reach around 319 million tonnes of oil equivalent in 2015. This compares with 209 million tonnes of oil equivalent in 2002.

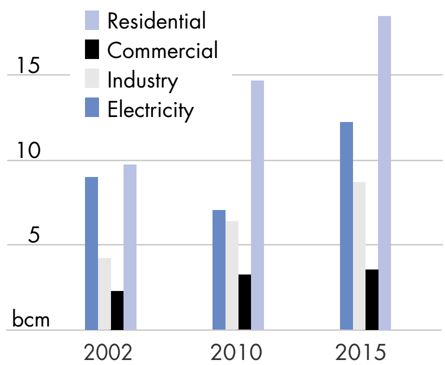
Natural gas is projected to remain one of the fastest growing fuels in Korea, averaging 5.0 per cent growth a year over the period 2001–15 to reach 45.9 billion cubic metres (equivalent to 33.3 million tonnes of LNG), compared with 24.5 billion cubic metres in 2002. The share of gas in Korea's primary energy consumption mix is also projected to rise, from 11 per cent in 2002 to 13 per cent in 2015 (figure 31).

31 Primary energy consumption, by fuel, Korea



Most of the growth in Korea's gas consumption will be driven by the residential sector, which is projected to rise by 5.7 per cent a year out to 2015. Underpinning this increase in demand is a continuing switch from coal and oil to natural gas, and growing demand for gas cooling systems as incomes rise and technologies for modular gas cooling units are further developed. Consumption of gas in the electricity sector is expected to grow by around 3.6 per cent a year over the outlook period. The fall in gas consumption in the electricity sector in 2010 shown in figure 32 reflects the assumed fall in gas fired electricity generation in this period discussed earlier.

32 **Projected natural gas consumption, by sector, Korea**



Natural gas demand and supply balance

Korea currently has mid and long term contracts for 19.4 million tonnes of LNG a year. Long term contracted supply is scheduled to increase from 2005, when POSCO and SK Power are expected to begin importing around 1.1 million tonnes of LNG a year for 20 years. POSCO's imports of 0.55 million tonnes a year are expected to begin in the second half of 2005. Imports by SK Power will commence when its planned LNG fired power plant is operational. This is currently expected to be in 2006.

However, Korea's first long term contract with Indonesia is due to expire in 2007. KOGAS recently sought bids for three 20 year contracts for 1.5 million tonnes a year each, with options for an additional five years and 0.5 million tonnes a year, from 2008.

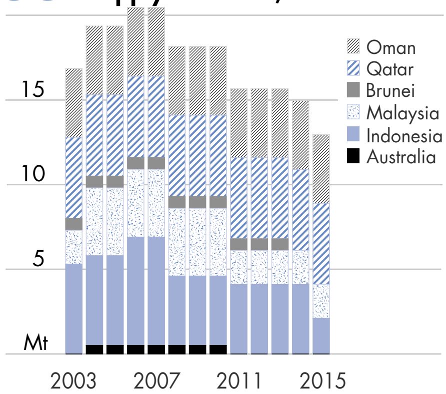
Natural gas demand in Korea is projected to be equivalent to 24.2 million tonnes of LNG in

21 **Projected natural gas demand and supply, Korea**

	2010	2015
	Mt	Mt
Projected gas demand	24.2	33.3
Projected domestic supply	0.4	0.4
Projected LNG imports	23.8	32.9
Existing LNG contracts	18.1	13.0
Projected uncontracted gas demand	5.7	19.9

2010, of which 0.4 million tonnes will be supplied by domestic gas production from the Donghae 1 project. Excluding the long term contracts currently under negotiation, total contracted supply in 2010 will be 18.1 million tonnes. Based on these projections, uncontracted demand in Korea will be around 5.7 million tonnes by 2010 (table 21). This is similar to the volume KOGAS is currently seeking. The level of uncontracted demand could be greater if the decline in gas fired power generation projected by the Korean government does not materialise.

33 **Existing mid/long term LNG supply contracts, Korea**



The size of uncontracted demand becomes more significant after 2010, when stronger growth in natural gas demand is forecast than in the earlier part of the outlook period. Stronger growth in demand is compounded by the expiry of the two mid term LNG contracts with Malaysia and Australia in 2010, and two long term contracts with Brunei and Indonesia in 2013 and 2014 respectively (figure 33). With total gas demand projected to reach 33.3 million tonnes in 2015, uncontracted demand in that year could be around 19.9 million tonnes.

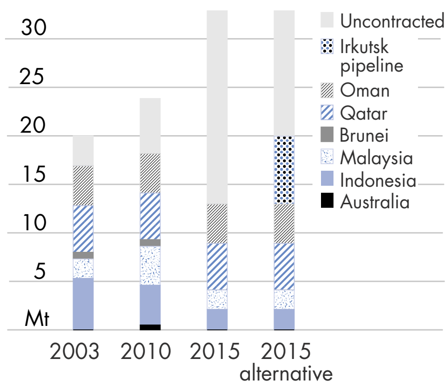
Future gas supply options

The projected gap between current contracted levels of LNG and projected demand over the outlook period is likely to provide a serious challenge for Korea in the coming years. The shortfall is exacerbated by the significant seasonal fluctuations in Korean gas demand. In the absence of significant domestic reserves, there are two options for Korea to meet the anticipated gas supply shortfall — to sign new LNG import contracts and to import natural gas via an international pipeline.

In the short to medium term, Korea will continue to rely on LNG imports to meet demand. Until the current round of long term contracts commence in 2008, Korea is likely to continue to increase purchases of spot LNG cargoes, short term contracts and cargo swaps with other countries such as Japan. Further long term supply contracts will be required from 2010 to meet Korea's projected gas demand.

Over the longer term, there is some potential to develop pipeline natural gas supply to Korea from the Russian Federation. A feasibility study on a pipeline from Irkutsk in eastern Siberia through northern China, then a subsea pipeline to Korea, was completed in November 2003. The study still requires approval by all three governments and the resolving of final issues, including prices. The Korean government considers that supply from the Irkutsk pipeline could begin from 2008–10 and that it could deliver 7 million tonnes of natural gas a year to Korea for 30 years. However, construction of the pipeline would have to begin rapidly to be operational within this timeframe, and this is looking increasingly unlikely. The commercial viability of the project also depends to a large extent on the commitment of China to the pipeline — without demand from China, there is unlikely to be sufficient gas to justify construction of the pipeline on commercial grounds.

34 Projected LNG imports, Korea



Korea's decision to introduce pipeline natural gas will depend on energy security concerns, including its policies of supply diversification, and more significantly, on its competitiveness with imported LNG. Some analysts have expressed doubts that pipeline natural gas could compete in Korea with LNG over such long distances (Platts 2003a,b). Other recent trends, including greater flexibility in the terms and conditions on which LNG is available, including an ability to meet Korea's seasonal demand patterns, can also be expected to increase the attractiveness of LNG.

If a natural gas pipeline were introduced to the Korean market, the need for additional LNG contracts would be lower than indicated in table 21. However, even if the Irkutsk pipeline is assumed to supply 7 million tonnes of gas a year to Korea by 2015, the volume of uncontracted demand in that year is projected to be around 12.9 million tonnes (excluding contracts currently under negotiation), providing significant opportunities for additional LNG (figure 34).

Chinese Taipei

Since its introduction into the market in 1990, LNG has represented an increasingly important part of Chinese Taipei's energy consumption mix. In addition, Chinese Taipei has become an important regional market for LNG, accounting for around 7 per cent of Asia Pacific LNG trade in 2003. Gas demand is expected to grow strongly in Chinese Taipei over the next decade, supported by robust economic growth, significant gas fired power generation capacity additions, and government policies that encourage the use of gas.

With few domestic gas resources and no prospects for pipeline gas imports, LNG will continue play a major role in Chinese Taipei's gas market. Chinese Taipei is likely to see a shortfall in gas supply emerging over the coming years, which will need to be met by additional LNG contracts. Plans to liberalise gas supply in Chinese Taipei could help to ensure that the terms of future LNG procurement are competitive.

Economic overview

Chinese Taipei's GDP has grown rapidly over the past two decades, at an average annual rate of 6.6 per cent since 1980. While Chinese Taipei was not badly affected by the Asian economic slowdown of 1997-98, the global economic downturn in 2001 led the economy into recession as world demand for consumer electronics and computer products fell sharply. However, Chinese Taipei's economy returned to moderate growth in 2002 and 2003 of 3.6 per cent and 3.2 per cent respectively (table 22). Economic growth in 2004 is forecast to reach 5.5 per cent, reflecting stronger world economic growth, and growth in industrial production and exports (Penm 2004).

Energy consumption

Underpinned by strong economic performance, primary energy consumption in Chinese Taipei has increased rapidly over the past two decades, at close to 6 per cent a year. Total primary energy consumption reached 94 million tonnes of oil equivalent in 2002, compared with 29 million tonnes of oil equivalent in 1980 (table 22).

Chinese Taipei's energy system has remained highly dependent on oil and coal over that period. Oil accounted for 45 per cent of Chinese Taipei's total

22 Key economic indicators, Chinese Taipei

		1980	1990	2000	2002	Annual growth 1980–90	1990–2000	2000–02
						%	%	%
Real GDP (1995 prices)	US$b	86.1	184.4	343.8	348.0	7.9	6.4	0.6
Population	million	17.8	20.4	22.2	22.5	1.3	0.9	0.5
Energy consumption a	Mtoe	28.5	48.1	83.0	93.6	5.4	5.6	6.2
Energy intensity	toe/US$'000	0.33	0.26	0.24	0.27	–2.4	–0.8	5.5
Energy consumption per person	toe	1.60	2.36	3.74	4.17	4.0	4.7	5.6

a Excludes combustible renewables and waste.
Source: IEA (2004b).

primary energy consumption in 2002, although its share has fallen markedly over the past two decades (table 23). In contrast, the contribution of coal to primary energy consumption has risen from 14 per cent in 1980 to 36 per cent in 2002. This is partly the result of fuel diversification strategies in Chinese Taipei and partly because of coal's competitiveness relative to oil as a fuel for electricity generation. Since the introduction of LNG in Chinese Taipei in 1990, the share of natural gas in total primary energy consumption has increased from 4 per cent to 7 per cent in 2002. In contrast, the role of nuclear power has fallen over the past decade to 11 per cent of primary energy consumption in 2002, compared with 18 per cent in 1990.

23 Total primary energy consumption, Chinese Taipei

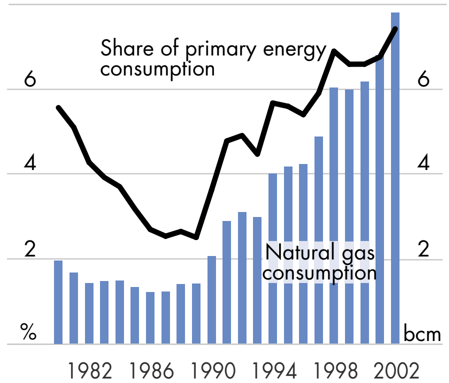
	1980		1990		2000		2002	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Coal	3.9	13.6	11.2	23.4	29.4	35.4	33.3	35.6
Oil	20.6	72.4	25.9	53.8	37.3	45.0	42.5	45.4
Natural gas	1.6	5.6	1.7	3.6	5.5	6.6	6.9	7.4
Nuclear	2.1	7.5	8.6	17.8	10.0	12.1	10.3	11.0
Renewables	0.3	0.9	0.7	1.5	0.8	0.9	0.5	0.6
Total **a**	28.5	100.0	48.1	100.0	83.0	100.0	93.6	100.0

a Excludes combustible renewables and waste.
Source: IEA (2004b).

Natural gas consumption

Chinese Taipei's natural gas consumption remained fairly low during the 1980s, reflecting limited domestic gas reserves. However, consumption has grown by 11.8 per cent a year on average since 1990 — when LNG was introduced — to reach 7.8 billion cubic metres (equivalent to 5.7 million tonnes of LNG) in 2002. This compares with 2.1 billion cubic metres in 1990 (IEA 2003a; figure 35).

35 Natural gas consumption, Chinese Taipei



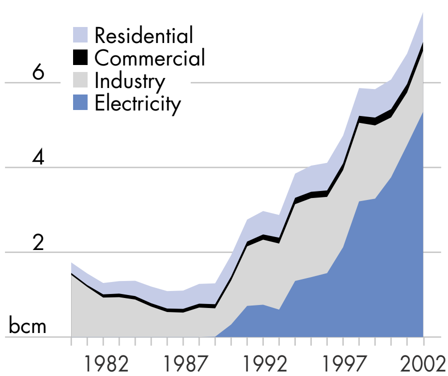
Gas use, by sector

The electricity sector has been the primary driver of the growth in gas use in the past decade and currently accounts for more than two thirds of total natural gas consumption in Chinese Taipei (IEA 2004b; figure 36). The growth in the use of gas in electricity generation coincides with the introduction of LNG, which is chiefly supplied to the power sector. The industry sector is the other main user of natural gas in Chinese Taipei, accounting for around 19 per cent in 2002. The residential sector accounted for 9 per cent of natural gas consumption in that year.

Coal accounts for more than half of electricity generation in Chinese Taipei, followed by nuclear power. However, LNG has made significant inroads in the power generation sector since the early 1990s, and in 2002 it accounted for around 10 per cent of total electricity generated, compared with 1 per cent a decade previously (table 24).

While natural gas consumption in end use sectors has grown strongly

36 Natural gas consumption, by sector, Chinese Taipei



24 Electricity generation, by fuel, Chinese Taipei

	1980		1990		2000		2002	
	TWh	%	TWh	%	TWh	%	TWh	%
Coal	6.0	14.0	25.9	28.7	94.0	48.7	114.8	55.4
Oil	25.5	59.9	22.4	24.7	34.5	17.9	25.9	12.5
Natural gas	0.0	0.0	1.1	1.2	17.1	8.9	20.6	9.9
Nuclear	8.2	19.2	32.9	36.3	38.5	20.0	39.6	19.1
Renewables	2.9	6.9	8.2	9.0	8.9	4.6	6.3	3.1
Total	42.6	100.0	90.5	100.0	193.0	100.0	207.2	100.0

Source: IEA (2004b).

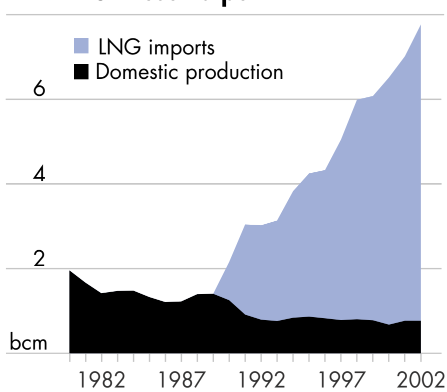
over the past decade, recent trends suggest a decline in consumption growth in these sectors. In industry, this is correlated with the overall contraction in output of sectors such as ceramics and glass manufacturing, which have traditionally used natural gas as their main energy source. The relatively low penetration of gas in the residential and commercial sectors reflects a number of factors, including the competitiveness of liquefied petroleum gas (LPG) relative to LNG, the limited geographical coverage of gas distribution networks, particularly in southern and central Chinese Taipei, and the high fixed costs involved in connecting new residential premises to gas distribution networks.

Natural gas supply

Domestic production

Chinese Taipei has limited domestic gas reserves, mainly in the north western part of the island. Proven economic reserves were estimated to be 76 billion cubic metres (equivalent to 55 million tonnes of LNG) at end 2003 (OGJ 2003). Domestic gas production has been steady over the past decade and was 0.8 billion cubic metres in 2002 (IEA 2003a; figure 37). Gas produced domestically represents

37 Gas supply sources, Chinese Taipei



only a small proportion of total natural gas consumption, around 10 per cent in 2002. This compares with 61 per cent of consumption in 1990.

25 LNG imports, by source, Chinese Taipei, 2003

	Mt	%
Indonesia	3.4	62.6
Malaysia	2.0	37.4
Total	5.5	100.0

Source: BP (2004).

LNG imports

In order to supplement indigenous gas production and diversify Chinese Taipei's energy mix, LNG imports were introduced in 1990. The annual growth in LNG consumption over the period to 2003 has averaged 18 per cent. LNG imports in 2003 were 5.5 million tonnes, equivalent to around 7 per cent of Asia Pacific LNG trade. Chinese Taipei currently sources all of its LNG requirements from two countries, Indonesia and Malaysia, which accounted for 63 per cent and 37 per cent of LNG imports respectively (table 25).

As the single wholesale supplier of LNG into the Chinese Taipei market, the government-owned Chinese Petroleum Corporation (CPC) has long term contractual arrangements with LNG exporters in Indonesia and Malaysia for 5.7 million tonnes of LNG a year (table 26). The first of these contracts is due to expire in 2009. CPC also recently agreed to purchase around 3.0 million tonnes a year for 25 years from Qatar from 2008 (reaching full volumes in 2011), around half of which will be used to supply the large gas fired Tatan plant to be built in the north.

In 2001, CPC supplemented its LNG contracts with a spot market purchase of 0.6 million tonnes from Oman, a result of a shortfall in nuclear power generation (figure 38). However, Chinese Taipei's LNG demand in recent

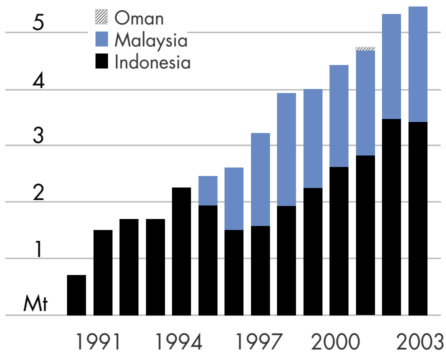
26 Existing long term LNG supply contracts, Chinese Taipei

Source	Project name	Importer	Volume	Duration
			Mtpa	
Indonesia	Bontang	CPC	1.6	1990–2009
Malaysia	MLNG II	CPC	2.3	1995–2015
Indonesia	Bontang	CPC	1.8	1998–2017
Total			5.7	

Source: CPC (2002).

years has been below contracted levels, reflecting slower than projected economic growth and delays in the development of gas fired power plants. This has resulted in CPC selling, redirecting and swapping a number of cargoes with other buyers, including in Japan and Korea, to assist in managing the oversupply situation. In addition, CPC reduced its offtake from contracts between 1998 and 2001, but agreed to take additional volumes from suppliers in future years under 'make good' contract provisions.

38 LNG imports, by source, Chinese Taipei



LNG import infrastructure

CPC constructed and operates the Yungan LNG receiving terminal located in southern Chinese Taipei (table 27). Following the completion of an expansion project in 2003, the terminal has an official handling capacity of 7.4 million tonnes a year (Energy Commission 2003). There are also plans to build a terminal in the north by the end of the decade. The most likely site is Taichung, with the proposed second LNG receiving terminal to be placed strategically to supply the substantial planned additions to gas fired generation capacity in the rapidly growing northern region.

27 LNG receiving terminals, Chinese Taipei

	Operator	Start up	Capacity	Imports 2003
			Mtpa	Mt
Existing				
Yungan	CPC	1990	7.4	5.5
Proposed				
Taichung	CPC	2010	3.0	–

Sources: Energy Commission (2003); FACTS Inc. (2004a).

Outlook for natural gas demand

Key assumptions for Chinese Taipei

GDP in Chinese Taipei is assumed to grow at an average annual rate of 4.0 per cent between 2001 and 2015. The pace of growth in the United States economy, global demand for information and communications technologies and the growth of Chinese Taipei investment in mainland China will be key factors affecting Chinese Taipei's growth prospects in the medium term.

28 Assumed fuel mix in electricity generation, Chinese Taipei

	2002	2010	2015
	%	%	%
Coal	55.4	38.2	46.5
Oil	12.5	5.9	5.9
Natural gas	9.9	25.2	23.4
Nuclear	19.1	26.7	19.9
Renewables	3.1	4.0	4.2
Total	100.0	100.0	100.0

Coal is expected to remain the dominant fuel source for power generation in Chinese Taipei over the outlook period, reflecting to a large extent its competitiveness relative to other fuels. The contribution of oil to the fuel mix in electricity generation is expected to fall from 13 per cent in 2002 to 6 per cent in 2015. In contrast, the share of gas is expected to rise from 10 per cent in 2002 to 23 per cent in 2015 (table 28). The increase in the share of natural gas for power generation is based on expected significant expansions in gas fired generation capacity from both Taipower (in particular the Tatan power plant) and independent power producers (IPPs). These expansions reflect government policy to reduce oil dependency and increase the use of natural gas for electricity generation on economic, environmental and energy security grounds.

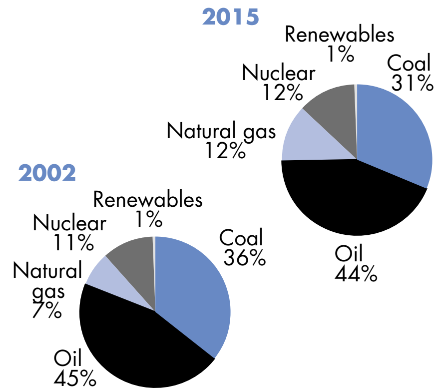
Natural gas demand projections

Reflecting the growth in economic output, total primary energy consumption in Chinese Taipei is projected to grow at an average annual rate of 2.3 per cent from 89 million tonnes of oil equivalent in 2001 to 122 million tonnes of oil equivalent in 2015. This is a marked reduction in the rate of growth relative to the 1990s, but is consistent with the lower economic growth projections and continuing structural shifts toward less energy intensive industries such as the information and communications technology sector and services.

Natural gas is forecast to be the fastest growing fuel in Chinese Taipei's energy mix. Gas consumption is projected to grow by 7 per cent a year from 6.7 billion cubic metres in 2001 to 17.3 billion cubic metres (equivalent to 12.6 million tonnes of LNG) in 2015. By 2015, it is projected that gas will account for around 12 per cent of total primary energy consumption, compared with 7 per cent in 2002 (figure 39).

The majority of growth in natural gas demand in Chinese Taipei is expected to occur in the electricity sector, driven by growth in IPP gas fired capacity (figure 40). To promote energy diversification and environmental objectives, the most recent phase of IPP bidding included a government requirement that new capacity be gas fired. As a result, close to 85 per cent of total generation capacity additions by IPPs by 2010 is expected to be LNG fired. Gas use for power generation is therefore projected to increase at an average annual rate of 8.4 per cent to reach 14.1 billion cubic metres by 2015, compared with around 4.5 billion cubic metres in 2001.

39 **Primary energy consumption, by fuel, Chinese Taipei**

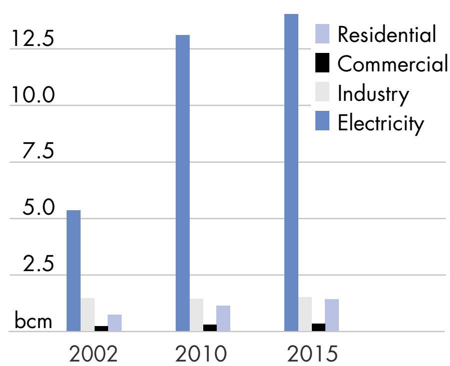


In the residential sector, gas use is projected to double over the outlook period to around 1.4 billion cubic metres by 2015. Growth in gas use is expected to be insignificant in other sectors of the economy, reflecting the limited coverage of pipeline networks, and a continued contraction in overall output in key gas using industries such as ceramics and glass manufacturing.

Natural gas demand and supply balance

Given Chinese Taipei's limited domestic gas reserves and relatively flat production in recent years, domestic gas supply is unlikely to expand and is held fixed at current levels of 0.5 million tonnes a year over the period to 2015. With no prospects for pipeline gas imports in the near future, the remainder of Chinese Taipei's natural gas demand is expected to be met through additional LNG imports. Reflecting

40 **Projected natural gas consumption, by sector, Chinese Taipei**



this, demand for LNG is likely to reach 11.1 million tonnes in 2010, and 12.1 million tonnes by 2015 (table 29).

29 Projected natural gas demand and supply, Chinese Taipei

	2010	2015
	Mt	Mt
Projected natural gas demand	11.6	12.6
Projected domestic supply	0.5	0.5
Projected LNG imports	11.1	12.1
Existing LNG contracts	6.6	7.1
Projected uncontracted gas demand	4.5	5.0

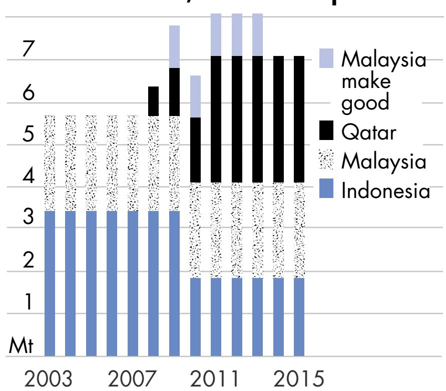
CPC's existing contracts for 5.7 million tonnes of LNG a year will contribute to meeting a large proportion of Chinese Taipei's LNG demand over the short to medium term. However, this volume will decline following the expiration of its first contract with Indonesia after 2009 (figure 41).

CPC also recently committed to an additional 3.0–3.2 million tonnes a year from Qatar's RasGas. Of this, 1.7 million tonnes will be dedicated to supplying Taipower's Tatan gas fired power plant. Contractual arrangements have not yet been finalised, but it is understood that LNG supply to Tatan will begin from 2008 and ramp up to 1.7 million tonnes from 2011. Reports indicate that RasGas will begin supplying the full volume of 3.0 million tonnes to CPC from 2011 (Platts 2003c).

CPC also has additional 'make good' LNG supplies as a result of taking lower volumes than it had contracted between 1998 and 2001. It is understood that Chinese Taipei will import around 1 million tonnes a year from Malaysia under 'make good' arrangements between 2009 and 2013.

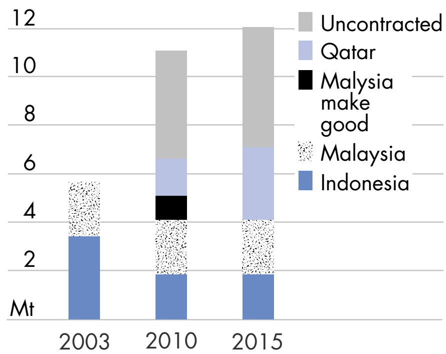
Despite these arrangements, there is a projected increase in LNG import demand above LNG supply volumes over the outlook period of at least 4.5 and 5 million tonnes in 2010 and 2015 respectively (table 29; figure 42). This will need to be met through additional LNG import contracts.

41 Existing long term LNG supply contracts, Chinese Taipei



Recent LNG procurement activities in Chinese Taipei have been difficult, with the tender to supply LNG to Tatan, eventually won by CPC and RasGas, requiring three attempts to achieve a result. Plans to liberalise gas supply in Chinese Taipei could help to ensure that the terms of future LNG procurement are competitive.

42 Projected LNG imports, Chinese Taipei



India

In early 2004 India became the most recent LNG import market in the Asia Pacific region, in order to assist in meeting its growing demand for gas. Natural gas has increased in importance in India's energy sector following two decades of government led development. However, subsidised domestic gas prices have resulted in chronic shortages of gas throughout the economy. With few price incentives for producers, domestic gas supply has been significantly below levels of demand and has constrained growth in gas consumption.

There is potential for significant growth in India's natural gas consumption in the next decade, driven by forecast strong growth in the economy and electricity sector, and to address environmental problems. The availability of natural gas in India is also likely to increase, with significant recent discoveries of local gas. However, even with new reserves, development of India's domestic natural gas supply is not likely to keep pace with demand. With the potential development of international gas pipelines from Iran and Bangladesh currently stalled as a result of geopolitical tensions, there is significant scope to increase imports of LNG in the near future.

Economic overview

Over the past two decades, reforms in India's economy and its growing integration into the world economy have resulted in GDP growth of 5.6 per cent a year since 1980 (table 30). Economic growth slowed in 2002 to 4.6 per cent, largely as a result of a drought induced fall in agricultural output (ADB 2003). GDP returned to strong growth in 2003, increasing by an estimated

30 Key economic indicators, India

						Annual growth		
		1980	1990	2000	2002	1980–90	1990–2000	2000–02
						%	%	%
Real GDP (1995 prices)	US$b	156.9	275.6	470.3	517.3	5.8	5.5	4.9
Population	million	687.3	849.5	1 015.9	1 048.6	2.1	1.8	1.6
Energy consumption **a**	Mtoe	94.9	189.4	315.2	330.1	7.2	5.2	2.3
Energy intensity	toe/US$'000	0.60	0.69	0.67	0.64	1.3	–0.3	–2.4
Energy consumption per person	toe	0.14	0.22	0.31	0.31	4.9	3.4	0.7

a Excludes combustible renewables and waste.
Source: IEA (2004b).

8.2 per cent, led by the services sector. Economic growth in 2004 is forecast to be 6.2 per cent (Penm 2004).

Energy consumption

Fuelled by strong economic growth and a large and growing population, energy consumption in India has increased by around 6 per cent a year over the past two decades. Total primary energy consumption has more than tripled from 95 million tonnes of oil equivalent in 1980 to reach 330 million tonnes of oil equivalent in 2002 (table 30).

In 2002, coal accounted for more than half of India's total primary energy consumption, excluding non-commercial fuels (table 31). Oil is the other main source of energy in India, representing more than one third of primary energy consumption. Natural gas accounted for 7 per cent of India's energy mix in 2002, a significant increase from only 1 per cent in 1980.

Natural gas consumption

While significant gas discoveries were made in the 1970s, it was not until the 1980s that the Indian government began developing the natural gas sector in earnest. The development involved subsidising natural gas prices to end users and undertaking significant investments in natural gas infrastructure (Wybrew-Bond and Stern 2002). These policies were successful in stimu-

31 Total primary energy consumption, India

	1980		1990		2000		2002	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Coal	54.9	57.8	109.2	57.6	168.9	53.6	178.2	54.0
Oil	34.0	35.9	62.6	33.1	114.4	36.3	118.5	35.9
Natural gas	1.2	1.3	9.8	5.2	21.0	6.7	22.6	6.8
Nuclear	0.8	0.8	1.6	0.8	4.4	1.4	5.1	1.5
Renewables	4.0	4.2	6.2	3.3	6.5	2.1	5.7	1.7
Total **a**	94.9	100.0	189.4	100.0	315.2	100.0	330.1	100.0

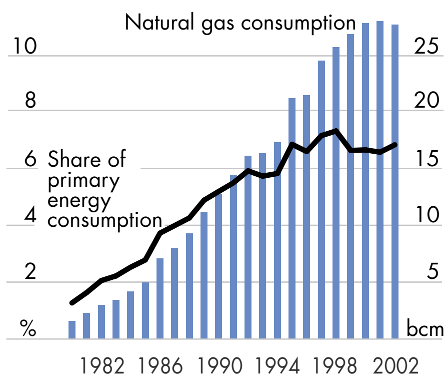
a Excludes combustible renewables and waste.
Source: IEA (2004b).

lating the gas sector, and India's natural gas consumption grew from 1.3 billion cubic metres in 1980 to 26 billion cubic metres (equivalent to 19 million tonnes of LNG) in 2002 (IEA 2003a; figure 43). This is equal to an average annual growth of 14 per cent over that period. Relatively weak gas demand growth in the past few years has largely resulted from restricted gas availability.

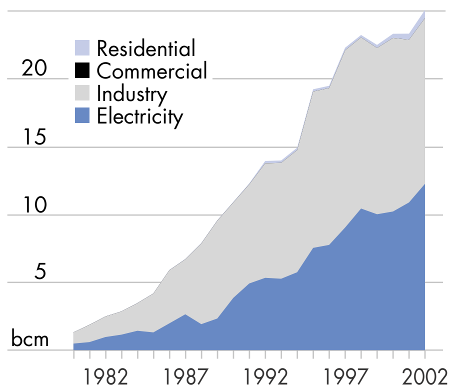
Gas use, by sector

Subsided gas prices have encouraged the use in gas in a range of sectors. However, as a result of significant gas shortages, gas in India is allocated by the government to critical sectors of the economy according to their perceived need for gas at that time (Wybrew-Bond and Stern 2002). This has meant that most of India's available gas is allocated to power generation and fertiliser produc-

43 Natural gas consumption, India



44 Natural gas consumption, by sector, India



32 Electricity generation, by fuel, India

	1980		1990		2000		2002	
	TWh	%	TWh	%	TWh	%	TWh	%
Coal	59.1	49.5	189.1	65.3	381.8	68.2	418.1	70.3
Oil	10.0	8.4	12.5	4.3	28.7	5.1	27.8	4.7
Natural gas	0.6	0.5	10.0	3.4	56.0	10.0	62.9	10.6
Nuclear	3.0	2.5	6.1	2.1	16.9	3.0	19.4	3.3
Renewables	46.6	39.0	71.7	24.8	76.1	13.6	66.6	11.2
Total	119.3	100.0	289.4	100.0	559.5	100.0	594.7	100.0

Source: IEA (2004b).

tion. Reflecting this allocation, nearly half of India's gas consumption in 2002 was in the industry sector, mainly for use in the chemicals and petrochemicals industry to produce urea (IEA 2004b; figure 44). The remaining half of gas consumption in that year was in the electricity sector. A very small volume of gas is also used in the residential sector.

Coal provided more than 70 per cent of India's electricity generation in 2002, compared with 50 per cent two decades earlier (table 32). The other major fuel for electricity generation is hydropower, which accounted for around 11 per cent of output in 2002. Natural gas also accounted for 11 per cent of India's electricity output in that year, compared with 1 per cent in 1980.

India plans to increase the use of natural gas in the residential, commercial and industry sectors and is investing heavily in infrastructure. India's natural gas infrastructure is currently based around the 2700 kilometre Hazira–Bijapur–Jagdishpur (HBJ) pipeline, which transports gas from Hazira on India's west coast to demand centres around Delhi in the north. Plans for development are based around the expansion of the HBJ pipeline and the eventual creation of a national gas grid (Gail-Infraline 2003; EIA 2004c).

Natural gas supply

Domestic production

India's proven natural gas reserves were estimated to be around 840 billion cubic metres (equivalent to 613 million tonnes of LNG) at 1 January 2004 (OGJ 2003). The majority of India's natural gas reserves are found in the

Bombay High basin off the north west coast and in the state of Gujarat. More recently, significant offshore gas reserves have been discovered along India's south east coast in the Krishna Godavarika (KG) basin, offshore from the state of Andhra Pradesh (Gail-Infraline 2003). While there is some uncertainty about the size of reserves in the KG basin, the current estimate for total reserves in place is 240 billion cubic metres (Platts 2003d). This field is the first discovery by a private Indian company and will have different marketing arrangements from state gas supplies.

Domestic gas production has increased in line with consumption over the past two decades, from 1.5 billion cubic metres in 1980 to 27.7 billion cubic metres in 2002 (IEA 2003a). Until 2004, domestic production had supplied India's entire natural gas market. It has been estimated that Indian gas consumption would be significantly higher if adequate domestic supplies were available (Gail-Infraline 2003).

India currently has a multi tiered gas pricing scheme. As mentioned previously, India's natural gas is currently sold at subsidised prices by government owned companies. These low prices have contributed to continued gas shortages and also act as a deterrent to private investors, whose higher gas supply prices have difficulty competing with subsidised prices and alternative fuels (Platts 2003e). The introduction of LNG has introduced a further level of gas prices into the Indian market.

LNG imports

India began importing LNG in January 2004, through a 25 year contract with Qatar's RasGas (table 33). Imports into India's Dahej receiving terminal in the west coast state of Gujarat are expected to be 2.5 million tonnes in 2004, rising to 5 million tonnes a year from 2005. The contract with Qatar also contains provision for an additional 2.5 million tonnes a year destined for the planned Kochin receiving terminal. However, as discussed below, there is some uncertainty surrounding the timing of the additional terminal.

The initial volumes of LNG flow into the HBJ pipeline and are being used mainly in the industry sector as a substitute for naphtha in refineries and some other industries. It is understood that other major potential end users such as power plants and fertiliser producers have been reluctant to sign supply contracts because of uncertainty over the pricing of LNG and its competitiveness relative to domestic gas and other fuels (FACTS Inc. 2004a; Platts 2004a).

33 Existing long term LNG supply contracts, India

Source	Project name	Importer	Amount	Duration
			Mtpa	
Qatar	RasGas	Petronet LNG	5.0	2004–29

Source: Platts (2004a).

LNG import infrastructure

India initiated ambitious plans for LNG in the 1990s, with India's Foreign Investment Promotion Board approving 12 prospective LNG import terminal projects by the end of the decade (EIA 2004c). However, many of these projects have failed to progress beyond the approval stage.

At present, the 5 million tonne a year Dahej terminal in Gujarat is India's only operative LNG terminal (table 34). Petronet LNG, the terminal's operator, is currently discussing plans to expand the terminal capacity to 10 million tonnes a year by the end of the decade (Energy Argus 2004b).

34 LNG receiving terminals, India

	Operator	Capacity	Start up
		Mtpa	
Existing			
Dahej	Petronet LNG	5.0	2004
Under construction			
Hazira	Shell	2.5	late 2004
Dabhol	Dabhol Power	5.0	–
Possible			
Dahej expansion	Petronet LNG	5.0	2007–08
Hazira expansion	Shell	2.5	–
Kochin	Petronet LNG	2.5	–
Mangalore		2.5	–
Pipavav		2.5	–
Kakinada		2.5	–
Jamnagar		–	–

Sources: Energy Argus (2004a,b); Platts (2004a).

The Hazira terminal, also located in Gujarat, is currently under construction and expected to be on line by the end of 2004. The terminal will have an initial annual capacity of 2.5 million tonnes, but could be expanded easily to receive 5 million tonnes a year (Shell 2004a). The source of LNG imports for the terminal has not yet been announced.

Also close to completion is the 5 million tonne a year Dabhol terminal, although the commissioning of this project is less certain. The terminal was around 90 per cent complete when construction was halted in June 2001 (Banerjee 2003; EIA 2004c). The Dahbol power plant has been idle since a dispute over power tariffs and sales between the owner of the plant (in which the bankrupt Enron held a majority share) and the Maharashtra State Electricity Board. The dispute led to the Board halting payments and the owner halting construction of the second phase of the project. The plant, which was running on naphtha in the first phase, was due to switch to LNG once the second phase was complete. Litigation has since prevented completion of the project, despite electricity shortages in the state (Energy Argus 2004a). The future of the two LNG supply contracts linked to the project, around 2.1 million tonnes a year from Oman and the UAE, is also uncertain.

A 2.5 million tonne a year LNG receiving terminal at Kochi port in the south west state of Kerala is also proposed, to be operational before the end of the decade. However, there is reported to be some uncertainty about likely gas consumption volumes in the region, with plans for a major LNG fired power plant in the area recently canceled (Platts 2004b).

There are several other sites for possible LNG receiving terminals that have been mooted, including Pipavav, Jamnagar, Mangalore and Kakinada, each for around 2.5 million tonnes a year capacity. However, the current status and viability of these projects is uncertain and it is unlikely that they will all proceed in the coming decade.

Outlook for natural gas demand

Key assumptions for India

GDP growth in India is assumed to remain close to its current rate, averaging 5.2 per cent a year in the period 2001–15. However, the effectiveness of ongoing economic reforms, including in the energy sector, will be a key determinant of India’s growth prospects over the outlook period. In particular, the expansion in power generation capacity required to support economic growth will only be achieved if electricity market reforms can respond effectively to the ongoing financial difficulties of the State Electricity Boards.

35 Assumed fuel mix in electricity generation, India

	2002	2010	2015
	%	%	%
Coal	70.3	65.2	63.5
Oil	4.7	1.3	1.2
Natural gas	10.6	14.4	16.6
Nuclear	3.3	2.8	3.1
Renewables	11.2	16.3	15.6
Total	100.0	100.0	100.0

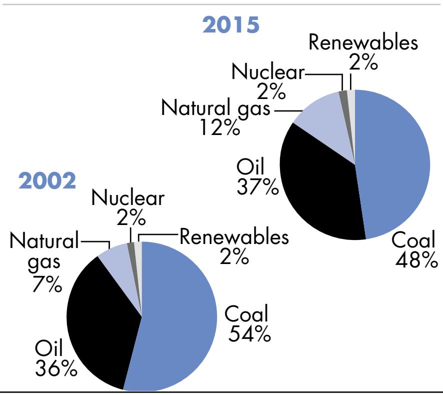
While coal is expected to remain the dominant fuel for power generation in India, its share is likely to fall by 2015. In contrast, the importance of natural gas in power generation is expected to grow significantly to reach 16.6 per cent of electricity output at 2015 (table 35). Natural gas is a cleaner fuel for electricity generation than coal, and supplies have been enhanced by LNG imports and the recent discovery of large gas reserves in the KG basin.

Natural gas demand projections

Driven largely by the assumed growth in GDP, total primary energy consumption in India is projected to grow at an average annual rate of 4.2 per cent, reaching 570 million tonnes of oil equivalent in 2015, compared with 319 million tonnes of oil equivalent in 2001. This is similar to the rate of growth in energy consumption in the 1990s.

Strong growth in natural gas consumption in India is forecast relative to that of coal, oil and non-fossil fuels. Natural gas consumption is expected to grow by 8.2 per cent a year to reach 70 billion cubic metres (equivalent to 51 million tonnes of LNG) in 2015 and account for around 12 per cent of total primary energy consumption (figure 45). In comparison, natural gas consumption in 2001 was 23 billion cubic metres.

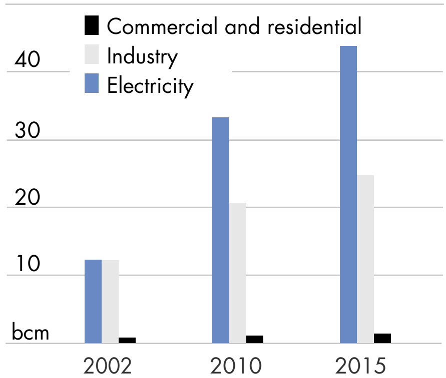
45 Primary energy consumption, by fuel, India



Note: totals may not add to 100, as a result of rounding.

Much of the projected growth in natural gas consumption over the outlook period occurs in India's electricity sector. Gas consumption in the electricity sector is expected to be nearly double that of the industry sector by 2015 (figure 46). Gas use in the power sector is projected to increase at an average annual rate of 10.5 per cent, from around 11 billion cubic metres in 2001 to 44 billion cubic metres by 2015. This strong growth reflects the shift in electricity generation toward natural gas, as well as the pace of growth in overall electricity output. Power generation in India is projected to expand at an average rate of 4.1 per cent a year over the period 2001–15. However, realising this projection will depend on achieving expansions in generating capacity.

46 **Projected natural gas consumption, by sector, India**



Many of India's State Electricity Boards are effectively bankrupt and are not in a position to fund new investments or even to purchase power from IPPs. To achieve rapid expansion in power generating capacity required to sustain economic growth, India will require greater private investment. The 2003 reforms to India's electricity law have made private investment a plausible option, permitting IPPs to directly supply bulk customers and power traders (Platts 2004c).

India's fertiliser industry accounts for almost all of consumption of gas in the industry sector, and this trend is likely to continue in the medium term. Industrial consumption of gas is projected to expand to 25 billion cubic metres in 2015. However, this outlook assumes that the fertiliser industry remains heavily subsidised. If these subsidies were reduced, the outlook for gas consumption in the sector could be considerably weaker.

Consumption of gas will remain insignificant in other sectors of India's economy, including by households, without significant additional infrastructure. Considerable additional investment in infrastructure is required to increase the penetration of natural gas in these sectors.

Natural gas demand and supply balance

As shown above, there is potential for rapid growth in India's gas market over the next ten years, although realising this potential will depend on the availability of gas supply, the competitiveness of LNG imports and the rate of development of gas infrastructure, including gas fired power generation capacity. Reliance, the company developing the KG basin, hopes to begin gas production from its fields by 2006-07. However, despite the availability of additional supply and potential further gas discoveries, domestic supply is not likely to keep pace with demand (Gail-Infraline 2003). This provides scope for greater gas imports over the outlook period.

India has three import options for gas over the period to 2015: LNG imports, a gas pipeline from Iran via Pakistan, and a pipeline from Bangladesh (FACTS Inc. 2004b). In the short term to medium term, LNG is expected to be the only option available for Indian gas imports. Based on this assumption, Indian LNG imports are projected to increase by 18 per cent a year during 2004–15, to reach 8.1 million tonnes by 2010 and 11.2 million tonnes by 2015 (table 36). This will involve an expansion at the existing import terminal and/or new LNG terminal projects.

India currently has one long term contract for 5.0 million tonnes of LNG a year from Qatar, with provision to increase to 7.5 million tonnes a year. Based on this supply contract and projected LNG imports, India could require an additional 3.1 million tonnes of LNG a year by 2010, with the potential shortfall rising to 6.2 million tonnes a year by 2015 (table 36; figure 47). Located close to the Middle East, it is expected that much of India's LNG imports will be sourced from the region.

Future gas supply options

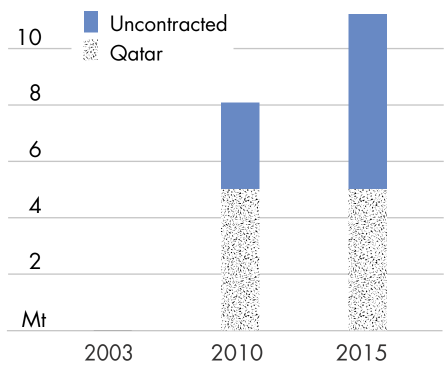
Over the medium to longer term, there is scope to supplement domestic supply and LNG imports with pipeline gas imports. However, to date, pipeline development has been stalled by geopolitical tensions in the region. One option for India is a pipeline from Bangladesh. However, Bangladesh has so far been reluctant to approve gas

36 Projected natural gas demand and supply, India

	2010	2015
	Mt	Mt
Projected natural gas demand	40.2	51.2
Projected domestic supply	32.1	40.0
Projected LNG imports	8.1	11.2
Existing LNG contracts	5.0	5.0
Projected uncontracted LNG demand	3.1	6.2

exports to India, until issues surrounding its own gas reserves and domestic supply security have been resolved (EIA 2004c).

47 **Projected LNG imports, India**



Another import option is a pipeline from Iran, either through Pakistan or subsea. It is believed the cost of a subsea pipeline is likely to be prohibitive, which leaves only the route via Pakistan economically feasible (IEA 2002). Iran and Pakistan are reported to be proceeding with the pipeline, however, to date, India has been reluctant to join on the grounds of supply security (Aspermont 2004a). Improved relations between India and Pakistan could accelerate development of the 2500 kilometre pipeline to India, but the project would still take several years to be operational.

In terms of price, pipeline gas import options for India are believed to be superior to LNG imports and could make it difficult for LNG to compete under current pricing arrangements (Gail-Infraline 2003). However, until energy security and political tensions surrounding pipeline gas imports are resolved, it is likely that all of India's gas imports will continue to be in the form of LNG.

China

To date, natural gas has played a relatively small role in China's coal dominated energy sector. However, consumption of natural gas has the potential to grow strongly in China, on the basis of continued rapid growth in economic activity, a policy imperative to increase the share of clean and efficient fuels in the energy supply mix and the expansion of natural gas infrastructure. China's growth in gas consumption will involve increases in both domestic production and the introduction of gas imports. Imports of LNG are likely to play an important role, particularly in China's rapidly growing eastern coastal region which lacks indigenous energy sources and where extended gas pipelines are not likely to be viable.

China's first two LNG receiving terminals are due on line in 2006 and 2007, with imports from Australia and Indonesia respectively. Several other LNG terminals along the east coast are also being discussed. Although there is potentially strong demand for LNG in eastern coastal China, realising an expansion in gas consumption will not be straightforward. Key factors that are relevant to gas market development are gas pricing, the pace of infrastructure development, the regulatory framework and the rules governing foreign investment. A key point to note is that LNG demand sources are being developed at the same time as supply arrangements, with new LNG fired power plants a key feature of each project.

Economic overview

China's economy has undergone significant transformation since the process of economic reform began in 1978. From a centralised and highly planned economy in the pre-reform period, China has moved progressively to a more open and market oriented economic system. The reform process has stimulated higher economic growth, with GDP expanding at an average annual rate of more than 9 per cent between 1980 and 2002 (table 37). GDP growth in 2002 was 8.0 per cent, rising to 9.1 per cent in 2003 on the back of strong increases in industrial production, investment, exports and consumer spending. In late 2003, the government implemented various policy measures to slow investment and bank lending and hence moderate the potentially overheating economy to a more sustainable pace. Economic growth in 2004 is forecast to be 8.5 per cent, although the rate of growth will depend to what

37 Key economic indicators, China

						Annual growth		
		1980	1990	2000	2002	1980–90	1990–2000	2000–02
						%	%	%
Real GDP (1995 prices)	US$b	164	398	1 041	1 209	9.3	10.1	7.7
Population	million	981	1 135	1 263	1 280	1.5	1.1	0.7
Energy consumption **a**	Mtoe	419	679	927	1 012	5.0	3.2	4.5
Energy intensity	toe/US$'000	2.6	1.7	0.9	0.8	–4.0	–6.3	–3.0
Energy consumption per person	toe	0.4	0.6	0.7	0.8	3.4	2.1	3.8

a Excludes combustible renewables and waste.
Source: IEA (2004b).

extent current government efforts to slow the economy are successful (Penm 2004; Penm and Fisher 2004).

Energy consumption

China is the world's second largest consumer of energy behind the United States and is also a major energy producer. Notwithstanding a recent slow down, total primary energy consumption grew by 4.1 per cent a year between 1980 and 2002 to reach 1012 million tonnes of oil equivalent in 2002, compared with 419 million tonnes of oil equivalent in 1980 (table 37).

One of the notable features of China's energy system is the dominance of coal in the fuel mix. Although the share of coal has declined in recent years, it still accounted for more than two thirds of total primary energy consumption in 2002, excluding non-commercial fuels (table 38). Oil accounted for a further 24 per cent in 2002, while natural gas, hydropower and nuclear power played relatively minor roles in the fuel structure. Although China has a long history of using natural gas, the share of gas in the fuel mix remains low at 3.1 per cent in 2002 and has not changed significantly over the past two decades.

Natural gas consumption

The low share of natural gas in China's energy mix is largely the result of the lack of an integrated national gas pipeline network and underdeveloped gas markets and institutions. The consumption of gas is often tied geograph-

38 Total primary energy consumption, China

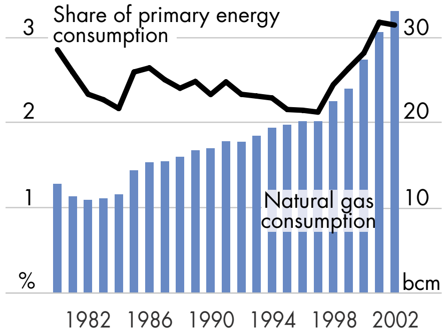
	1980		1990		2000		2002	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Coal	312.6	74.7	542.2	79.8	655.6	70.7	707.2	69.9
Oil	89.0	21.3	110.4	16.3	221.5	23.9	241.4	23.9
Natural gas	12.0	2.9	15.8	2.3	26.1	2.8	31.9	3.1
Nuclear	0.0	0.0	0.0	0.0	4.4	0.5	6.5	0.6
Renewables	5.0	1.2	10.9	1.6	19.1	2.1	24.8	2.4
Total **a**	418.6	100.0	679.4	100.0	926.7	100.0	1 011.8	100.0

a Excludes combustible renewables and waste.
Source: IEA (2004b).

ically to the major gas producing fields, especially in Sichuan province in China's southwest.

However, since the mid-1990s, natural gas has increased in significance in China's short and long term energy planning. It is now the focus of accelerated investment in exploration, production, transmission and LNG imports. The government has embarked on a major expansion of its gas infrastructure, including pipelines, power plants and LNG terminals, reflecting its large domestic resources and increased environmental pressures.

48 **Natural gas consumption, China**



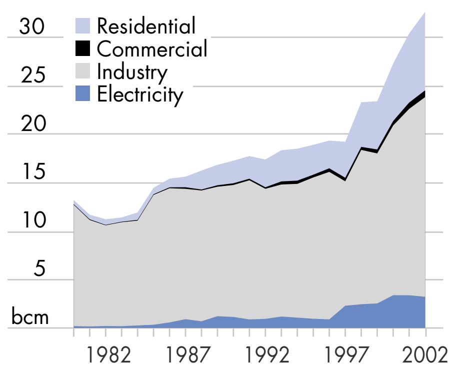
Natural gas consumption in China was 33.1 billion cubic metres (equivalent to 24.2 million tonnes of LNG) in 2002, compared with 12.8 billion cubic metres in 1980, an increase of 4.4 per cent a year (IEA 2003a; figure 48). Much of this growth has occurred in the past five years, with the annual rate of growth in consumption exceeding 10 per cent.

Gas use, by sector

Nearly two thirds of China's gas consumption currently occurs in the industry sector (IEA 2004b; figure 49). Much of this is as a feedstock for fertiliser plants, and in the oil and gas sector. The residential sector accounted for 25 per cent of gas consumption in 2002, while the electricity sector absorbed a further 10 per cent.

In 2002, only 0.3 per cent of electricity generation in China was gas fired (table 39). This share has been relatively constant over the past decade, and is limited by its ability to compete with low priced coal.

49 **Natural gas consumption, by sector, China**



39 Electricity generation, by fuel, China

	1980		1990		2000		2002	
	TWh	%	TWh	%	TWh	%	TWh	%
Coal	164.1	54.6	442.5	71.2	1 061.5	78.4	1 270.9	77.6
Oil	77.6	25.8	49.0	7.9	46.1	3.4	49.4	3.0
Natural gas	0.7	0.2	3.1	0.5	6.4	0.5	4.7	0.3
Nuclear	0.0	0.0	0.0	0.0	16.7	1.2	25.1	1.5
Renewables	58.2	19.4	126.7	20.4	222.4	16.4	288.0	17.6
Total	300.6	100.0	621.2	100.0	1 353.2	100.0	1 638.0	100.0

Source: IEA (2004b).

China's power sector is dominated by coal, which accounts for three quarters of electricity output in 2002, a major increase since 1980. The other main source of electricity generation is hydropower.

The recent expansion in gas consumption in the residential sector has been facilitated by the development of several regional pipelines, including to Beijing. However, the use of gas in end use sectors continues to be constrained by a lack of long distance gas pipelines and distribution networks in urban areas. China does not have a gas pipeline system for transporting gas nationally, although this is beginning to be formed. China's gas consumers are generally located close to gas fields and there are few or no linkages between pipeline networks. China's most recent major pipeline — the west to east pipeline — links natural gas deposits in the western Xinjiang province to four eastern provinces as well as Shanghai. Additional gas reserves in the central Ordos Basin also connect to the pipeline. The first stage of the project was completed in late 2003, with the full 4200 kilometre pipeline operational in late 2004. This project will significantly increase gas volumes available in eastern coastal regions.

Natural gas supply

Domestic production

China has significant natural gas resources, both onshore and offshore. Total gas resources are estimated at around 38 trillion cubic metres, of which about 80 per cent are onshore resources and 20 per cent offshore (Xu 2002). However, proved recoverable reserves are much lower at around 1.5 trillion cubic metres at 1 January 2004 (OGJ 2003). Most of China's onshore gas resources are underdeveloped and widely distributed across the country. The country's largest reserves of natural gas are located in western and north central China, away from areas of large demand. This necessitates a significant investment in pipeline infrastructure to carry it to eastern provinces, including the west to east pipeline.

At present, China's natural gas consumption is supplied entirely by domestic sources. China's three gas producers are state controlled companies, each of which focuses its operations in a different part of the country: PetroChina, Sinopec and China National Offshore Oil Corporation (CNOOC).

LNG imports

In 2001, China approved the construction of the country's first LNG receiving terminal in Guangdong province. In 2002, Australia's North West Shelf project was granted the foundation contract to supply around 3.3 million tonnes of LNG a year to the terminal for 25 years (table 40). Supply is expected to begin from mid-2006. In conjunction with the terminal, Guangdong province has launched a project to build six 320 megawatts gas fired power plants and to convert some existing oil fired plants to LNG.

Shortly after the Guangdong contract was awarded, China announced that Indonesia's Tangguh project had been selected to supply a second LNG terminal in Fujian province. The contractual volume is 2.6 million tonnes a year for 25 years and is scheduled to commence in 2007.

LNG import infrastructure

The Guangdong and Fujian import terminals are currently under construction, although the latter is in preliminary stages only (table 41). The Guangdong terminal will have an annual capacity of 3.7 million tonnes, while a second phase expansion is also planned for around 2008. The Fujian

40 Existing long term LNG supply contracts, China

Source	Project	Destination	Volume	Duration
			Mtpa	
Australia	North West Shelf	Guangdong	3.3	2006–31
Indonesia	Tangguh	Fujian	2.6	2007–32

41 LNG receiving terminals, China

	Operator	Capacity	Start up
		Mtpa	
Under construction			
Shenzen, Guangdong	CNOOC	3.7	2006
Putian, Fujian	CNOOC	2.6	2007
Possible			
Guangdong Phase 2	CNOOC	2.0–3.0	2008
Ningbo, Zhejiang	CNOOC	3.0	2009
Shanghai	CNOOC	3.0	2008
Tianjin	CNOOC	3.0	2010
Qingdao, Shandong	Sinopec	3.0	2010
Nantong, Jiangsu	CNOOC	–	–
Jiangsu	PetroChina	–	–
Dalian, Liaoning	CNOOC	–	–
Guangxi	PetroChina	–	–

Start up dates for possible terminals are based on company announcements.
Sources: Platts (2004d,e,f); Energy Argus (2004c); EIA (2003b).

terminal is expected to have an import capacity of around 2.6 million tonnes a year.

Several additional terminals that could be located in eastern coastal provinces by the end of the decade are also being discussed. These include a terminal in Zhejiang province by 2009, with an import capacity of 3 million tonnes of LNG a year, and in Shanghai by 2008, also with a capacity of 3 million tonnes a year. CNOOC has also announced plans to study the feasibility of an LNG terminal in Tianjin city, south of Beijing. The terminal would have an annual capacity of 3 million tonnes and be due for completion in 2010. A terminal at Qingdao in Shandong province, to be operational by the end of the decade, is also under discussion between Sinopec and local authorities. Other possible terminal locations include in Liaoning and Jiangsu provinces (Platts 2004d,e,f; Energy Argus 2004c). All of the proposed terminals in China have LNG fired combined cycle power plants as an integral part of the projects.

It is likely that a decision on many of the terminals will be influenced by the demonstrated success of the first terminal in Guangdong province.

Outlook for natural gas demand

Key assumptions for China

China's economy is assumed to continue to grow strongly, at an annual average rate of 8 per cent over the period 2001–15. This rapid growth will be supported by the productivity gains that will flow from ongoing economic reforms. For example, labor market reforms in China are facilitating the migration of surplus labor out of traditional agricultural industries into high marginal product industries.

The share of gas in electricity generation is expected to increase strongly to 5.4 per cent by 2015, implying significant additions to gas fired capacity over the outlook period. While the share of nuclear power is also expected to increase strongly, coal will continue to dominate China's electricity fuel mix, accounting for around three quarters of electricity output throughout the period to 2015 (table 42).

It is also assumed China begins importing LNG from both Australia and Indonesia in 2006 and 2007 respectively, and that three to four additional LNG projects could be operational by 2015.

Natural gas demand projections

Reflecting China's strong economic performance, energy consumption is projected to grow by 3.9 per cent a year, from 924 million tonnes of oil equivalent in 2001 to 1588 million tonnes of oil equivalent by 2015. Apart from nuclear, natural gas is expected to be the fastest growing fuel in China, expanding at an average annual rate of 6 per cent between 2001 and 2015. By 2015, China's natural gas consumption is projected to be 77 billion cubic metres (equivalent to 56 million tonnes of LNG) and account for 4.4 per cent of total primary energy consumption (figure 50).

42 Assumed fuel mix in electricity generation, China

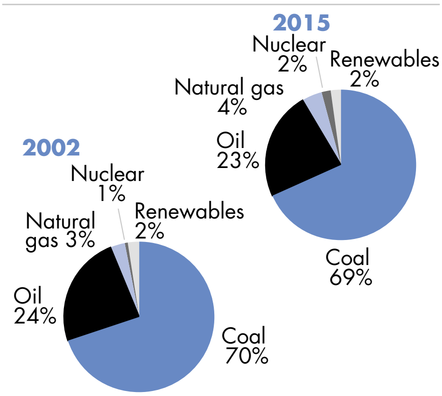
	2002	2010	2015
	%	%	%
Coal	77.6	75.3	73.7
Oil	3.0	2.2	1.9
Natural gas	0.3	3.9	5.4
Nuclear	1.5	3.9	4.2
Renewables	17.6	14.8	14.8
Total	100.0	100.0	100.0

Robust growth in natural gas consumption is expected in all sectors, but is likely to be strongest in the electricity sector (figure 51). Gas consumption in the electricity sector is projected to grow at an average rate of 14 per cent a year over the outlook period, supported by a shift toward gas and away from coal and oil. Consumption of gas by households also grows rapidly as average household incomes rise, expanding by an average rate of 7 per cent a year. While the industry sector continues to account for the largest share of China's gas consumption, its use of gas is forecast to grow more slowly than in other sectors.

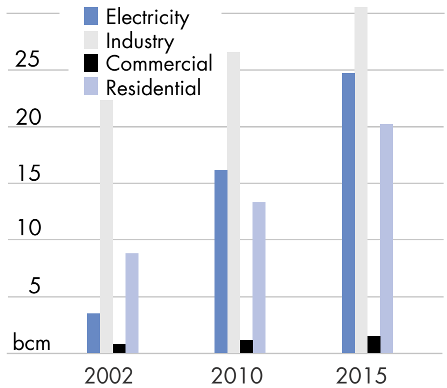
Natural gas demand and supply balance

Based on the above projections, the outlook for gas demand in China is positive. Realising the growth in demand, however, will require significant expansion in gas fired power generating capacity and gas infrastructure in the next few years. In particular, significant additional investment is required in domestic pipeline infrastructure and in LNG import terminals. Assuming that the required level of investment takes place, China's LNG imports could reach 7.7 million tonnes by 2010, rising to 18.3 million tonnes by 2015 as further capacity additions come on line (table 43). While this is lower than recent Chinese government projections, realising this forecast will still require significant resources to

50 Primary energy consumption, by fuel, China



51 Projected natural gas consumption, by sector, China



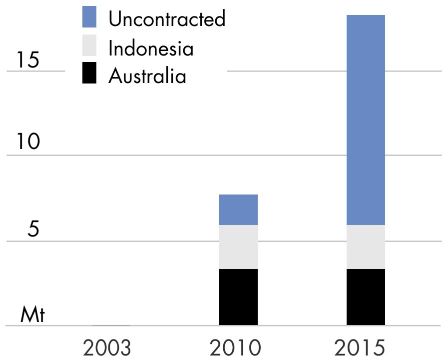
43 Projected natural gas demand and supply, China

	2010	2015
	Mt	Mt
Projected gas demand	41.8	56.2
Projected domestic supply	34.1	37.9
Projected LNG imports	7.7	18.3
Current LNG contracts	5.9	5.9
Projected uncontracted gas demand	1.8	12.4

construct import terminals and linking pipelines.

China has long term LNG supply contracts with Australia and Indonesia for around 5.9 million tonnes of LNG a year. China is likely to require additional LNG contracts before the end of the decade to meet projected LNG demand (figure 52). In 2010, the difference between existing LNG contracts and projected import demand is around 2 million tonnes, rising to more than 12 million tonnes by 2015.

52 **Projected LNG imports, China**



Future gas supply options

In the medium to longer term, China also has the option of importing natural gas from the Russian Federation and central Asia via pipeline. A pipeline from the Kovykta field near Irkutsk in eastern Siberia to northeast China, with a possible extension to Beijing, and then to Korea was the subject of a recent feasibility study. The pipeline is scheduled to supply 12 billion cubic metres (equivalent to 9 million tonnes of LNG) to China from around 2008, increasing to 20 billion cubic metres later, of which about 5 billion cubic metres could go to Beijing. However, the project has not yet received approval from the three governments involved, and several outstanding issues, including pricing, are yet to be resolved. In light of its slow progress and China's emphasis on the development of domestic reserves, the project is unlikely to proceed in the coming decade (Yamaguchi and Cho 2003).

Even if the Irkutsk pipeline did materialise during the period to 2015, its impact on China's imports of LNG is likely to be marginal. This is because LNG will be used mostly in China's eastern coastal region, particularly in southern China, whereas Russian pipeline gas will be used principally in northern areas. China currently lacks a national pipeline network to connect the two areas.

The Philippines

The Philippines' natural gas sector is in the early stages of development. The inauguration of the Malampaya gas to power project in late 2001 has significantly increased the role of natural gas in the economy in the past few years. However, the costs of using domestic gas reserves in the Philippines are relatively high compared with other countries in the Asia Pacific region. This feature, along with strong forecast growth in gas demand and the expected depletion of Malampaya reserves by the end of the following decade, has raised the possibility of LNG imports. The Philippines government is currently planning to begin importing LNG toward the end of this decade, in order to supplement domestic production. Approval was recently given for the site of the country's first LNG receiving terminal.

Economic overview

Since 1980, economic growth in the Philippines has fluctuated, with periods of high growth punctuated by periods of recession. Between 1980 and 2001, GDP grew at an average annual rate of 2.5 per cent. However, over the past decade, a more stable domestic political environment, coupled with institutional and economic reform, has resulted in more consistent economic growth (ADB 2003) (table 44). In 2002 and 2003, GDP increased strongly, by 5.5 per cent and 4.9 per cent respectively, supported by rapid expansion in the industry and services sectors. GDP in 2004 is forecast to grow by 4.5 per cent (Penm 2004).

44 Key economic indicators, Philippines

						Annual growth		
		1980	**1990**	**2000**	**2002**	**1980–90**	**1990–2000**	**2000–02**
						%	%	%
Real GDP (1995 prices)	US$b	56.3	66.6	89.9	96.7	1.7	3.0	3.7
Population	million	48.0	61.0	76.6	79.9	2.4	2.3	2.1
Energy consumption **a**	Mtoe	13.4	18.5	32.9	32.0	3.3	5.9	–1.4
Energy intensity	toe/US$'000	0.24	0.28	0.37	0.33	1.6	2.8	–4.9
Energy consumption per person	toe	0.28	0.30	0.43	0.40	0.8	3.5	–3.4

a Excludes combustible renewables and waste.
Source: IEA (2004b).

Energy consumption

Total primary energy consumption in the Philippines has increased at an average annual rate of 4.0 per cent since 1980 to reach 32 million tonnes of oil equivalent in 2002. This compares with 13 million tonnes of oil equivalent in 1980 (table 44).

Imported oil accounted for more than half of energy consumption in the Philippines in 2002, although its share has been falling over the past two decades (table 45). This reflects the development of domestic energy resources — notably geothermal, hydropower and coal, and more recently, natural gas — in order to reduce expenditure on oil imports. This trend is expected to continue under the current Philippine Energy Plan, which aims to significantly develop the coal and natural gas sectors (DOE 2003). Natural gas accounted for 4.5 per cent of total primary energy consumption in 2002, reflecting the recent development of the Malampaya gas field and gas fired power plants.

Natural gas consumption

The development of the Philippines natural gas sector is a key component of the government's energy policy, which is focused on improving energy self sufficiency and increasing private sector involvement in the Philippines' energy market. Natural gas consumption in the Philippines was negligible prior to 2001 but increased to around 1.6 billion cubic metres (equivalent to 1.2 million tonnes of LNG) in 2002 following the inauguration of the

45 Total primary energy consumption, Philippines

	1980		1990		2000		2002	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Coal	0.4	2.7	1.3	7.0	5.0	15.3	4.9	15.4
Oil	10.9	81.7	12.0	64.8	17.2	52.2	16.2	50.7
Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	1.4	4.5
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	2.1	15.6	5.2	28.2	10.7	32.4	9.4	29.4
Total **a**	13.4	100.0	18.5	100.0	32.9	100.0	32.0	100.0

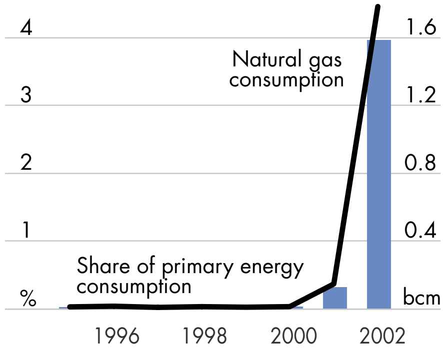
a Excludes combustible renewables and waste.
Source: IEA (2004b).

Malampaya gas to power project in late 2001 (IEA 2004b; figure 53).

Gas use, by sector

Currently all natural gas consumption in the Philippines occurs in the power sector. In 2001, gas accounted for a very marginal share of power generation, with the main fuel sources being coal, renewables and oil. However, the inauguration of the Malampaya gas to power project resulted in a more balanced mix of fuels in the Philippines' electricity sector in 2002, with gas increasing to 18 per cent of electricity output, mainly at the expense of oil and renewables (table 46).

53 **Natural gas consumption, Philippines**



As a result of the large volume of oil and coal capacity signed to long term take or pay contracts in response to power shortages in the early 1990s, and the slower than expected growth in electricity demand since the Asian financial downturn, the National Power Corporation is currently contracted to buy more electricity than it can sell. This overcapacity in some parts of the country could slow the development of further natural gas fired power generation capacity until these contracts begin to expire in 2012.

46 **Electricity generation, by fuel, Philippines**

	1980		**1990**		**2000**		**2002**	
	TWh	%	TWh	%	TWh	%	TWh	%
Coal	0.2	1.0	1.9	7.7	16.7	36.8	16.1	33.3
Oil	12.2	67.9	11.8	46.7	9.2	20.3	6.3	13.0
Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	8.8	18.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	5.6	31.1	11.5	45.7	19.4	42.9	17.3	35.6
Total **a**	18.0	100.0	25.2	100.0	45.3	100.0	48.5	100.0

a Excludes combustible renewables and waste.
Source: IEA (2004b).

In 2004, a small amount of gas will be used in the transport sector to fuel compressed natural gas vehicles (FACTS Inc. 2004c).

Natural gas supply

Domestic production

Proven recoverable natural gas reserves in the Philippines are estimated to be 106 billion cubic metres (equivalent to 77 million tonnes of LNG) at the beginning of 2004 (OGJ 2003). The Philippines has two gas producing fields, Malampaya and San Antonio. Malampaya reserves are approximately 84 billion cubic metres. At the current rate of production, the fields are expected to be depleted by the end of the next decade (FACTS Inc. 2004c).

Gas in the Philippines is sourced solely from domestic fields. The offshore Malampaya field provides the majority of production. However, gas sourced from Malampaya is relatively expensive compared with other Asian gas sources, because of the high costs of deepwater exploration and the length of pipeline required to transport the gas to market. The Philippines' high gas prices, along with expected increases in power demand and its limited gas reserves, has raised the option of LNG imports (FACTS Inc. 2004c).

LNG imports

The Philippines is currently considering options to import LNG to meet a potential gap between domestic gas supply and demand toward the end of the decade. Three potential sites for LNG terminals have been proposed, and the first LNG terminal permit was awarded to local utility GN Power in March 2004. GN Power's proposed terminal in Mariveles, on the southern tip of Bataan to the west of Manila, is targeted for completion by 2007-08 (table 47). The terminal is expected to have an annual LNG import capacity of 1.4

47 LNG receiving terminals, Philippines

	Operator	Capacity	Start up
		Mtpa	
Proposed			
Mariveles	GN Power	1.4	2007-08

Source: EIA (2003b).

48 Existing long term LNG supply contracts, Philippines

Source	Project	Destination	Volume	Duration
			Mtpa	
Indonesia **a**	Tangguh	GN Power	1.3	–

a Preliminary contract only.
Source: FACTS Inc. (2004c).

million tonnes (Aspermont 2004b; EIA 2003b). GN Power is also planning to construct a gas fired power plant in the region to begin operation around 2008-09. The company has a preliminary agreement with Indonesia's Tanguhh project for 1.3 million tonnes of LNG a year, although there has been little public discussion of the contract in recent years (table 48).

Outlook for natural gas demand

Key assumptions for the Philippines

Under the impetus of ongoing reforms, economic growth in the Philippines is assumed to average 4 per cent a year in the period from 2001 to 2015. However, stable growth will only be achieved if government reforms address structural problems in the Philippines economy, including insufficient investment in infrastructure.

Electricity fuel share assumptions are based on the Philippines' most recent Power Development Plan (DOE 2003). The share of gas fired power is assumed to grow from 18 per cent in 2002 to about 29 per cent by the end of the decade, and to maintain that share to the end of the projection period (table 49).

Natural gas demand projections

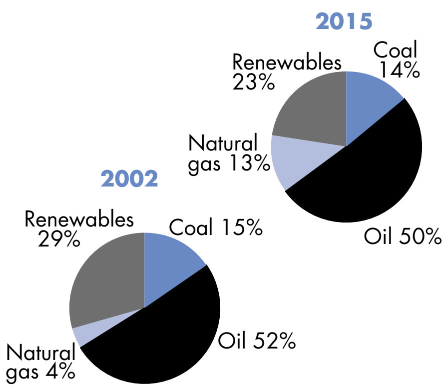
Reflecting expected robust growth in the economy, energy consumption in the Philippines is projected to expand at an average annual rate of 2.8 per cent to reach 48 million tonnes of oil equivalent in 2015. This compares with 32 million tonnes of oil equivalent in 2002.

49 Assumed fuel mix in electricity generation, Philippines

	2002	2010	2015
	%	%	%
Coal	33.3	31.1	30.7
Oil	13.0	13.0	12.8
Natural gas	18.1	29.4	29.5
Renewables	35.6	26.6	26.9
Total	100.0	100.0	100.0

The growth in gas consumption is expected to be more rapid, rising from 1.6 billion cubic metres in 2002 to 6.7 billion cubic metres (equivalent to 4.9 million tonnes of LNG) by 2015. In 2015, natural gas is expected to account for 12.5 per cent of total primary energy consumption in the Philippines (figure 54).

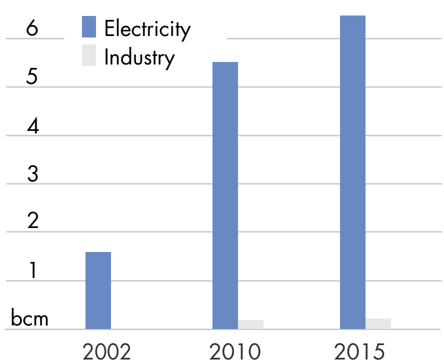
54 **Primary energy consumption, by fuel, Philippines**



Almost all of the Philippines' natural gas consumption will continue to occur in the electricity sector (figure 55). Electricity generation is projected to expand by more than 3 per cent a year to 2015, contributing to the growth in gas consumption in the electricity sector. Gas consumption in the power sector also expands at the expense of oil as the government seeks to reduce the Philippines' dependence on imported oil. By 2015, gas is expected to account for almost 30 per cent of electricity output, replacing oil as one of the three dominant sources of electricity.

No significant growth in gas consumption is projected to occur outside the electricity sector, although use is expected to begin in the industry sector by the end of the decade. Growth in these sectors is likely to be limited by a lack of significant development in city gas infrastructure during this timeframe.

55 **Projected natural gas consumption, by sector, Philippines**



Natural gas demand and supply balance

Gas supply projections by the Philippines Department of Energy are used in this study. Based on these projections that domestic gas supply will be equivalent to 3.2 million tonnes a year, mostly from the Malampaya field, domestic supply is likely to be lower than projected gas demand by the end of the decade. The projected shortfall between gas supply and demand could be equivalent to 1 million tonnes in 2010, rising to 1.7 million tonnes in 2015 (table 50; figure 56).

Future gas supply options

Exploration in the Philippines is currently underway to find additional reserves to supplement the Malampaya field, which is expected to be depleted by the end of the next decade. While discoveries of additional reserves are possible, the price of gas from any offshore discoveries is likely to be relatively expensive and could prohibit their development (FACTS Inc. 2004c).

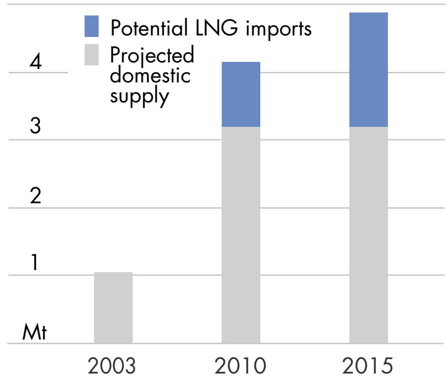
In view of this and the impending supply shortfall, the Philippines will probably require gas imports by the end of the decade. The Philippines has two options for imports, pipeline natural gas and LNG imports. There are plans for piped gas imports via Malaysia, as part of the proposed Trans-ASEAN Gas Pipeline Network. However, several factors suggest that the Philippines connection is unlikely to materialise by 2015, including its progress to date and because it is one of the final stages of the ASEAN network and one of the most expensive (Roberts, Cull and Day 2003).

The most likely option to meet the projected shortfall in the medium term, therefore, is LNG. Based on this assumption, LNG imports are projected to be around 1.7 million tonnes by 2015. As discussed earlier, the Philippines currently has a preliminary agreement with Indonesia's Tangguh project for 1.3 million tonnes a year.

50 Projected natural gas demand and supply, Philippines

	2010	2015
	Mt	Mt
Projected gas demand	4.2	4.9
Projected domestic supply	3.2	3.2
Projected gas supply shortfall	1.0	1.7
Potential LNG imports	1.0	1.7

56 Projected LNG imports, Philippines



New Zealand

Natural gas plays a key role in New Zealand's energy system following the discovery of large domestic reserves several decades ago, and is an important input to the electricity and industry sectors. However, estimates of the remaining reserves in Maui gas field, which has dominated New Zealand's energy sector, have been significantly downgraded in recent years and the field is now close to the end of its production life. In the coming decade, New Zealand gas supplies will increasingly be sourced from a larger number of smaller fields, inevitably at higher prices.

Based on current and known gas fields, New Zealand is likely to face a gas supply shortfall by the end of this decade. While there is currently significant exploration occurring that could yield new reserves, these supply sources will take several years to become available and could be costly to introduce. If no new economic gas reserves materialise, New Zealand has two options — to increase the use of coal fired power, or to import LNG to supplement domestic gas supplies. The feasibility of introducing LNG is being discussed in New Zealand.

Economic overview

The New Zealand economy has grown robustly over the past two decades, at an average annual rate of 2.4 per cent since 1980 (table 51). New Zealand has been one of the faster growing economies in the OECD in recent years, maintaining a robust economic growth rate during the more recent period of global downturn. Underpinning this strong performance has been a program of economic reforms, including improvements to labor market flexibility (OECD 2003). In 2002 and 2003, growth in GDP was 4.3 per cent and 3.4 per cent respectively. Economic growth in 2004 is forecast to be 4.0 per cent (Penm 2004).

Energy consumption

Energy consumption in New Zealand has increased by 3.1 per cent a year over the past two decades, driven by growth in economic output. Total primary energy consumption in 2002 reached 18 million tonnes of oil equivalent, compared with 8.7 million tonnes of oil equivalent in 1980 (table 51).

51 Key economic indicators, New Zealand

						Annual growth		
		1980	1990	2000	2002	1980 –90	1990 –2000	2000 –02
						%	%	%
Real GDP (1995 prices)	US$b	43.4	52.2	69.1	74.6	1.9	2.8	3.9
Population	million	3.1	3.4	3.9	4.0	0.8	1.3	1.3
Energy consumption	Mtoe	9.2	13.9	17.9	18.0	4.2	2.6	0.2
Energy intensity	toe/US$'000	0.21	0.27	0.26	0.24	2.3	–0.3	–3.5
Energy consumption per person	toe	2.93	4.08	4.63	4.53	3.4	1.3	–1.1

Source: IEA (2004a).

Oil is the main source of energy in New Zealand, accounting for around 35 per cent of total primary energy consumption in 2002 (table 52). Hydropower and geothermal also play a significant role, accounting for 30 per cent of New Zealand's energy mix. The share of natural gas has increased significantly over the past two decades, from 9 per cent in 1980 to 28 per cent in 2002.

Natural gas consumption

Gas consumption in New Zealand has increased at an average annual rate of 8.0 per cent since 1980, and in 2002, natural gas consumption was 6.1 billion cubic metres (equivalent to 4.5 million tonnes of LNG) (IEA 2003a; figure 57).

52 Total primary energy consumption, New Zealand

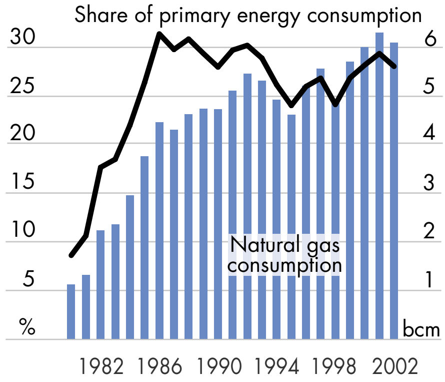
	1980		1990		2000		2002	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Coal	1.0	11.1	1.1	8.1	1.1	6.1	1.2	6.9
Oil	4.2	45.8	4.0	28.6	6.3	35.4	6.3	34.9
Natural gas	0.8	8.6	3.9	28.0	5.1	28.2	5.1	28.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	3.2	34.5	4.9	35.3	5.4	30.4	5.4	30.1
Total	9.2	100.0	13.9	100.0	17.9	100.0	18.0	100.0

Source: IEA (2004a).

Gas use, by sector

Around 48 per cent of the gas consumption in New Zealand in 2001 was in the industry sector, with the majority used in the petrochemicals industry by Methanex. Electricity generation accounted for a further 46 per cent of gas use in 2001, although the volume of gas consumed in this sector has fluctuated significantly over time (IEA 2004a; figure 58). Small amounts of gas are used in the commercial and residential sectors.

57 Natural gas consumption, New Zealand



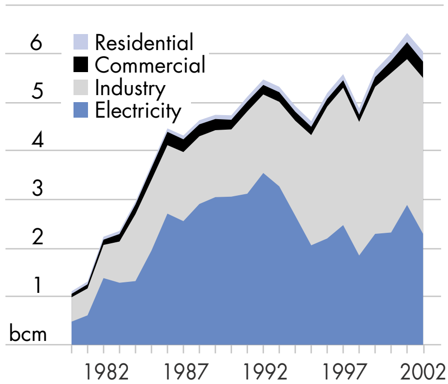
Gas accounted for 25 per cent of total power generation in 2002, a significant increase since 1980 as new combined cycle capacity and gas fired cogeneration have come on line (table 53). However, the share of gas fluctuates widely from year to year in New Zealand, and fell from 31 per cent in 2001. This is because the majority of New Zealand's electricity generation system is based on hydropower and the available water flows can vary considerably. In dry years, including recently, lower hydro generation is made up with increased thermal generation, much of which is supplied by gas (MED 2003). Coal accounts for only 4 per cent of power generation in New Zealand.

Natural gas supply

Domestic production

Currently all of New Zealand's gas consumption is met from domestic reserves. New Zealand's proven recoverable natural gas reserves are estimated to be 37 billion cubic metres (equivalent to 27 million tonnes of LNG) at the beginning of 2004 (OGJ 2003). This is dominated by the Maui field, which provided 72 per cent of New Zealand's total gas production in

58 Natural gas consumption, by sector, New Zealand



53 Electricity generation, by fuel, New Zealand

	1980		1990		2000		2002	
	TWh	%	TWh	%	TWh	%	TWh	%
Coal	0.4	1.9	0.5	1.5	1.0	2.6	1.6	4.0
Oil	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Natural gas	1.7	7.5	5.7	17.6	9.6	24.4	10.1	25.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	20.5	90.4	26.1	80.8	28.7	73.0	28.6	70.9
Total	22.6	100.0	32.3	100.0	39.2	100.0	40.3	100.0

Source: IEA (2004a).

2002. The other major gas field currently producing is the Kapuni field, which accounted for 12 per cent of production in that year. Other significant fields include the Pohukura and Kupe fields, although these have yet to begin production (MED 2003). Pohukura is currently being developed, with gas supply scheduled to begin mid-2006 (Shell 2004b).

However, the Maui field is becoming exhausted more quickly than originally anticipated. Estimated reserves in the field were downgraded from 32 billion cubic metres in 2001 to less than 14 billion cubic metres in 2002 (Energy Economist 2003). Gas discoveries in recent years have been below consumption rates, and there are no known fields to be developed that could replicate Maui production (Genesis 2004).

In addition to concerns about gas supply availability in the coming years, issues have been raised about the level of dependence on hydropower. There are concerns that a major drought could cause disruptions to New Zealand's power supply. The lack of alternative generating capacity has stemmed from the lower than expected volumes of gas discovered over the past few years and the fact that several gas fired power projects have been put on hold because of a lack of available feedstock (Energy Economist 2003).

Based on government projections for current and known gas fields, New Zealand is likely to face a gas supply shortfall by the end of this decade (MED 2003). While there is currently significant exploration occurring, which could yield new reserves, these supply sources will take several years to become available and could be costly to introduce. If no new economic gas reserves materialise, New Zealand has two options in the medium term

— to increase the use of coal fired power, or to import LNG to supplement domestic gas supplies.

While coal could provide a higher degree of security because of its relative abundance, New Zealand has a strong environmental focus in its energy policies. For example, the government has ratified the Kyoto Protocol, and the use of additional coal fired power generation could make achieving emission reduction targets more difficult. In light of these concerns, LNG imports may be an attractive option.

LNG imports

In the above context, New Zealand interest in LNG has grown strongly since 2003. New Zealand utilities Contact Energy and Genesis Power jointly investigated the feasibility of developing an LNG receiving terminal, and the role that LNG could play in meeting New Zealand's future energy needs (Genesis 2004). Several other power and energy companies are also reported to be examining siting and other issues connected with LNG imports. The feasibility study was completed in mid-2004, with recent announcements of the results suggesting LNG is a viable option for New Zealand (Aspermont 2004c).

Contact Energy and Genesis Power have publicly stated that they believe importing LNG is likely to be preferred to coal based electricity generation on present policy settings. They have suggested that imported LNG could be competitive with coal, wind and hydro electricity generation, assuming a moderate carbon charge (Platts 2003f).

Outlook for natural gas demand

Key assumptions for New Zealand

The economic outlook in New Zealand is expected to continue to be robust, with an assumed average annual rate of GDP growth of 3.2 per cent between 2001 and 2015.

Electricity fuel share assumptions in this study are consistent with the New Zealand government's current reference scenario as reported in Ministry of Economic Development (2003). In particular, the share of gas is expected to decline sharply over the short to medium term, reflecting the exhaustion of the Maui gas field. As new gas fields come on line, the share of gas in electricity generation is expected to recover slightly to 17 per cent in 2015 (table 54). Hydropower and geothermal are likely to be the main substitutes for gas in power generation, increasing to nearly three quarters of electricity output in 2015.

54 Assumed fuel mix in electricity generation, New Zealand

	2002	2010	2015
	%	%	%
Coal	4.0	3.7	3.0
Natural gas	25.1	16.0	17.1
Hydro and geothermal	69.0	74.2	72.9
Other renewables	1.9	6.1	6.9
Total	100.0	100.0	100.0

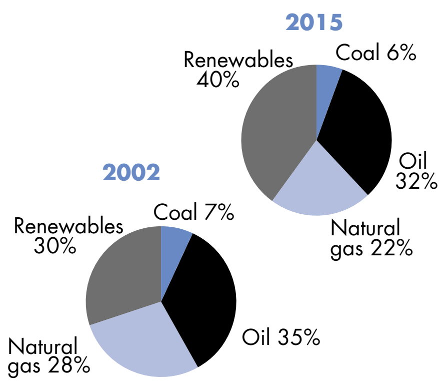
The decline in Maui gas production is also assumed to result in a fall in the consumption of gas in the petrochemicals industry over the short to medium term, in line with projections by the New Zealand government (MED 2003).

Natural gas demand projections

New Zealand's total primary energy consumption is projected to grow at an annual average rate of 1.9 per cent a year, reaching 23.5 million tonnes of oil equivalent by 2015. This compares with 17.1 million tonnes of oil equivalent in 2001. Energy consumption is forecast to grow more slowly than the expansion of the New Zealand economy, largely because of ongoing improvements in energy efficiency.

Natural gas use in New Zealand is projected to contract at an average rate of 0.4 per cent a year out to 2015, from 6.1 billion cubic metres in 2001 to 5.7 billion cubic metres (equivalent to 4.2 million tonnes of LNG) in 2015. However, much of the fall occurs in the early part of the projection period, rising again as new gas supplies become available. The share of gas in primary energy consumption is also forecast to decline, from 28 per cent in 2002 to 22 per cent by 2015 (figure 59).

59 Primary energy consumption, by fuel, New Zealand



The electricity and industry sectors dominate gas consumption in New Zealand, together accounting for more than 90 per cent of total gas consumption. In both sectors, the consumption of gas is projected to contract in the short term, before resuming positive growth to 2010 and 2015 (table 55). The expected rapid depletion of Maui gas reserves explains the sharp drop in gas consumption to 2005 in these sectors. As alternatives to Maui gas become available from 2006, gas consumption is expected to begin to rise again, but will be constrained by expected higher gas prices (MED 2003).

55 Annual growth in gas consumption, by sector, New Zealand

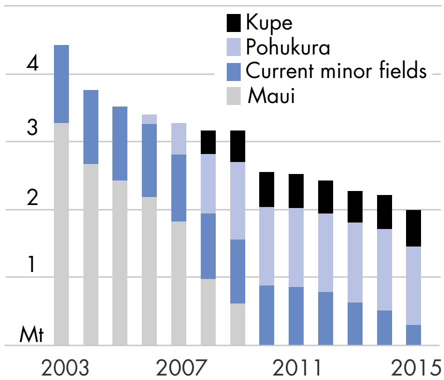
	2002 –15	2002 –05	2005 –10	2010 –15
	%	%	%	%
Electricity	–0.2	–11.0	4.0	2.6
Industry	–1.1	–9.0	1.5	1.3
Total	–0.4	–8.6	2.5	2.0

Industrial customers, including Methanex, will be most affected by the depletion of the Maui gas field. Methanex consumes about 35 per cent of New Zealand's gas supply and has operated with the benefit of low cost gas from the Maui gas field. Alternative sources of gas are reported to be as much as twice as expensive as Maui, thereby undermining the competitiveness of Methanex and other industrial customers (MED 2003).

Natural gas demand and supply balance

New Zealand government projections of gas supply over the period to 2015 are used in the study. Supplies from the Pohukura and Kupe fields are expected to become available in 2006 and 2008 respectively, but are not likely to be able to duplicate output from the Maui field. Domestic gas supply based on existing and known fields are projected to be equivalent to 2.5 million tonnes in 2010, falling to 2.0 million tonnes by 2015 (MED 2003; figure 60).

60 Projected domestic gas supply, New Zealand



Based on the above supply projections, the shortfall between known supply and the projected demand could be 1.3 million tonnes by 2010, rising to 2.2 million tonnes by 2015 as gas demand expands and existing supplies are depleted (table 56; figure 61).

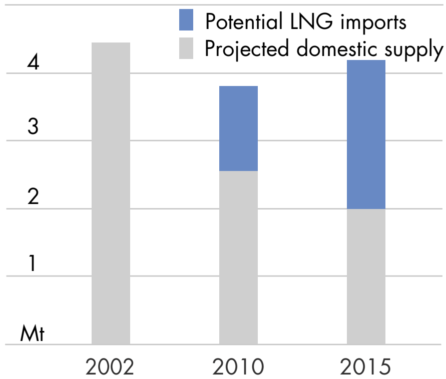
It is possible that some of the shortfall could be met by additional domestic gas supplies. Recent exploration activity has risen, and is expected to continue to be strong with the impending decline of Maui. The rate of gas exploration and hence gas discoveries in New Zealand has historically been deterred by the dominant and competitive position of Maui (MED 2003). As reserves at Maui are depleted, the gas price in New Zealand is expected to rise, making further exploration viable.

Alternatively, part if not all, of the shortfall could be met by the import of LNG. The earliest LNG could be onstream is toward the end of this decade.

56 Projected natural gas demand and supply, New Zealand

	2010	2015
	Mt	Mt
Projected gas demand	3.8	4.2
Projected domestic supply	2.5	2.0
Projected gas supply shortfall	1.3	2.2
Potential LNG imports	1.3	2.2

61 Projected LNG imports, New Zealand



4

regional LNG supply: recent trends and outlook

The strong projected growth in LNG demand in the Asia Pacific region outlined in the previous chapter will require significant investment in LNG supply capacity. This will provide opportunities for the eight existing suppliers of LNG to the region, as well as potential new entrants to the market. Competition to supply Asia Pacific markets is likely to remain strong, with new capacity either under construction or planned in most LNG exporting countries, including Australia. In addition, the Russian Federation is currently constructing its first LNG export facilities, due to begin supplying the Asia Pacific market toward the end of the decade. Iran and Yemen are also exploring options to export LNG to Asia, while Bolivia and Peru have proposed projects to supply the north American west coast (figure 62).

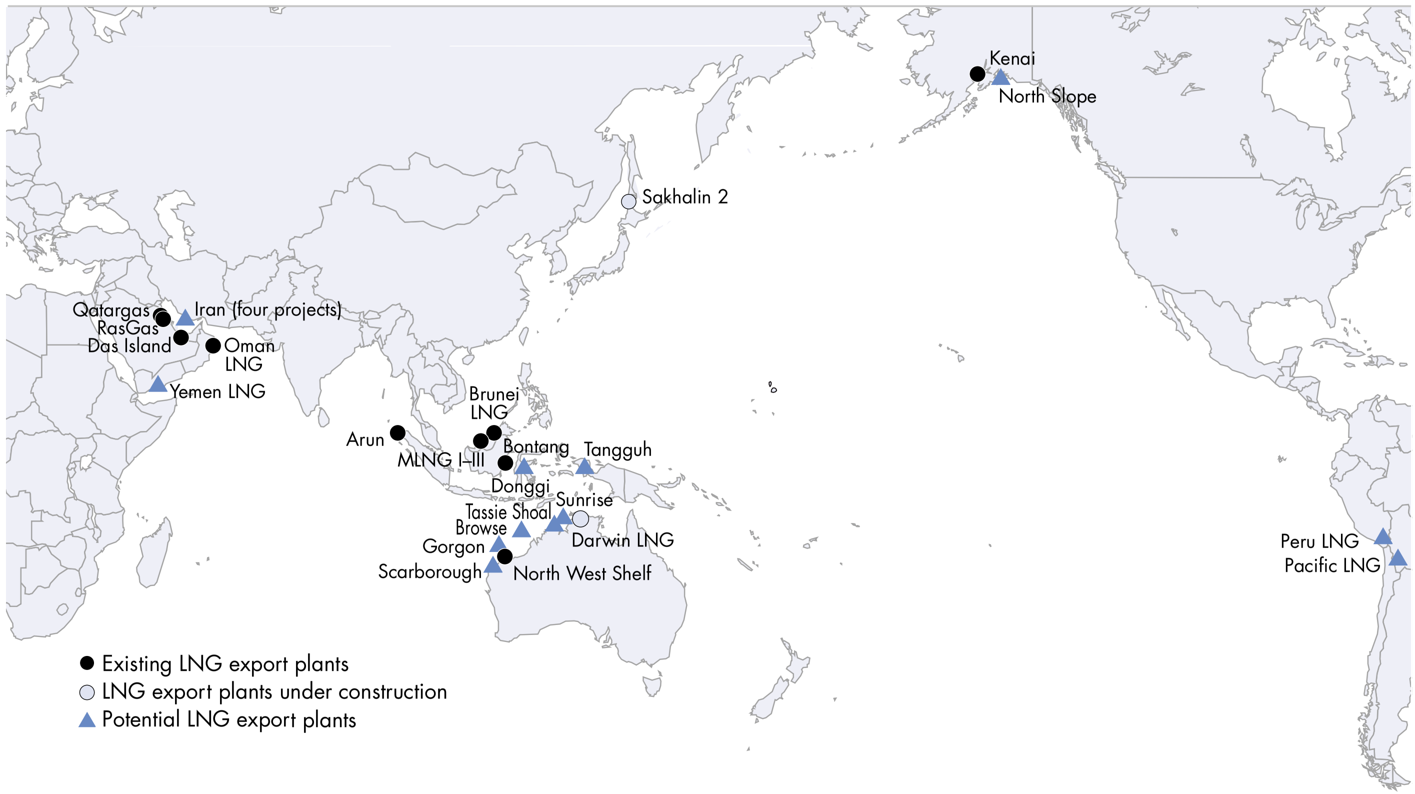
This chapter contains profiles of existing and known future suppliers of LNG to the Asia Pacific market. The suppliers profiled are Australia, Indonesia, Malaysia, Brunei, Alaska, Qatar, Oman, the United Arab Emirates and the Russian Federation. The profiles include analysis of gas reserves, gas production and trade, including LNG exports, existing LNG projects and long term LNG supply contracts. Also included is discussion of potential LNG supply capacity over the period to 2015.

In this study potential LNG supply capacity is estimated based on public statements in company and industry publications regarding the planned commencement date of LNG projects. No estimates are made by ABARE of the likelihood of projects being realised in the timeframe specified in public statements. Some of the projects will need to proceed quickly if they are to be operational in the stated timeframe, and it is probable that some projects will not be realised as planned.

Factors affecting future LNG supply

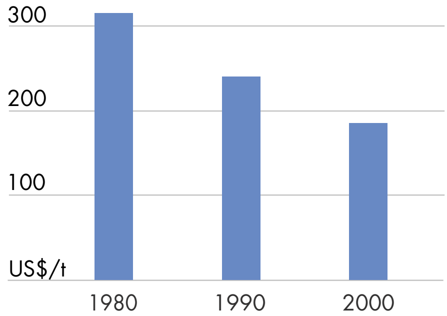
Along with the pace and distribution of growth in LNG demand, there is a range of factors that will shape the outlook for LNG supply into the Asia Pacific market. These include a trend toward larger liquefaction trains, a decline in liquefaction and LNG transport costs, the changing role and nature

62 Asia Pacific LNG export projects



of long term LNG supply contracts, competition to secure markets before projects proceed, and alternative options to commercialise gas reserves.

63 **Indicative capital costs for LNG projects**

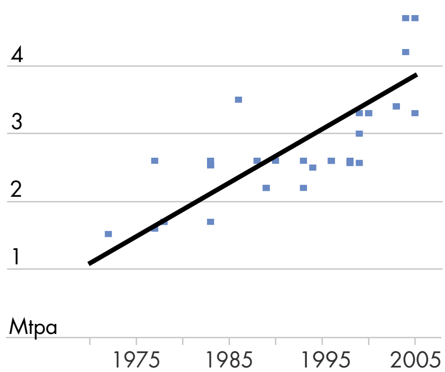


Declining liquefaction costs

Technological improvements in refrigeration and liquefaction processes have contributed to a significant reduction in capital costs of liquefaction in recent years (Shell 2004c; figure 63). While varying across LNG projects, the average cost of building a liquefaction plant has fallen from around US$350 per tonne of LNG in 1960 to around US$250 a tonne in 1990, and to slightly under US$200 a tonne in 2003, in nominal prices (Rojey and Chabrelie 2003).

The fall in costs is largely a result of economies of scale associated with larger trains, which result in lower costs per tonne of LNG as capacity increases. Current new train sizes are now around 4 million tonnes a year, compared with 2 million tonnes for those constructed in the early 1990s, and less than 1 million tonnes a year for those constructed in the 1960s (figure 64). Some of the most recent planned trains are for capacity greater than 7 million tonnes a year, including several proposed projects in Qatar. Further expansions in new train capacities are likely to continue to drive down per unit capital costs (IEA 2003b).

64 **Annual liquefaction capacity of LNG trains**



A reduction in production costs has also been achieved through expansions at existing projects. The costs of adding trains to existing projects are significantly lower than building a new greenfield plant, since many of the facility components are already in place. These projects need only add additional trains and sometimes additional wellhead supply and storage tanks to increase output (Rigby 2003). Generic liquefaction costs amount to around US$1.09/MBtu for a two train, 8 million tonne a year greenfield LNG project, and US$0.97/MBtu for an expansion train (EIA 2003b). Advances in technology, changes in design, and competition at engineering design and construction contract stage have also made a significant contribution to lower construction costs (Taylor Sen 2003a; Flower and King 2002).

However, since the LNG market is primarily driven by long term contracts with prices pegged to petroleum products, lower operating costs do not necessarily translate into lower LNG prices, at least in the short term.

LNG transport issues

As discussed in chapter 2, the world's LNG fleet consisted of 156 ships in April 2004, with an additional 62 on order for delivery by the end of 2007 (Bainbridge 2004). As with liquefaction costs, the cost of building LNG tankers has fallen dramatically, by more than 40 per cent during the past decade (IEA 2003b). In late 2003 the average price of a 138 000 cubic metre ship, which carries around 60 000 tonnes of LNG, was US$155 million, compared with US$280 million in the mid-1980s (in nominal prices) (EIA 2003b).

There are a number of reasons for the fall in the price of LNG tankers in the past few years, including increased competition as new shipyards enter the market, improved ship building techniques, weaker currencies against the US dollar in key building countries, and larger tanker sizes (Taylor Sen 2003a).

The enhanced competition among shipyards has been a key factor. Japanese yards built most of the LNG tankers in the 1980s and early 1990s. Since then, shipyards in France, Finland, Italy and Korea have built LNG tankers, with Korea becoming an important supplier of tankers.

The LNG industry is also building larger tankers, which results in lower per unit LNG shipping costs. Vessel size has increased over the past decade, with ships now generally between 138 000 and 145 000 cubic metres, with the largest vessel under construction around 153 000 cubic metres (Bainbridge

2004). Tankers of up to 250 000 cubic metres are currently being discussed, indicating the trend is likely to continue. The existing infrastructure at the receiving terminals throughout the world, however, has been designed for the existing fleet. The ability of receiving terminals to handle very large tankers may limit the increase in tanker size (Bainbridge 2004; IEA 2003b). Under present Japanese restrictions, for example, none of the large tankers under discussion could enter Japanese ports.

To meet the expected strong growth in LNG demand, the existing LNG tanker fleet will need to expand significantly. Such rapid growth is likely to put a strain on existing resources (Bainbridge 2004). While expanding recently, there are still only eight yards that currently build LNG tankers. However, India, China and Poland are planning to develop LNG tanker construction capabilities in their shipyards (EIA 2003b).

Also increasing the pressure on the existing fleet will be the expected rise not only in demand but also in distance traveled between supply and market. With the expansion in the share of trade from the Middle East, the mileage per tonne of LNG has been increasing, and as the United States LNG market expands, this trend is expected to continue. With tankers fully utilised at present, there is limited ability to accommodate a shift to longer LNG routes in the short run (Bainbridge 2004).

A further emerging issue in LNG supply is the shipping route itself. Over the past few years, pirate activities in the South China Sea and the Straits of Malacca have presented a growing threat to the shipping and trading activities of regional vessels. Around one third of world trade passes through the Straits of Malacca, with more than 50 000 commercial vessels travelling through the narrow waterway each year. This includes much of the world's LNG trade, with concerns being raised about the possibility of using LNG tankers as part of terrorist activities.

Role of long term contracts

Even though the capital cost of facilities — liquefaction plants, ships and regasification terminals — has fallen considerably over recent years, LNG remains a relatively capital intensive business. The lead time required for LNG development projects is significant: construction alone can take more than three years, and investment decisions have to be taken well in advance of when demand is expected to materialise.

A key issue in the development of LNG projects is the need to find a suitable market for much of the gas prior to development, and in particular a buyer prepared to sign a long term purchase contract at a price sufficient to justify the large investment in LNG production. With many LNG export projects planned to supply the Asia Pacific market in the coming years, competition between projects to secure markets is likely to be intense, with only those able to secure markets likely to proceed to completion.

Almost all projects developed to date have been on the basis of long term contracts between the different parties along the supply chain: gas producers, the LNG liquefaction project sponsor, the LNG buyer and large final consumers. 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. This is one disadvantage of LNG projects over other gas reserve development options, including gas to liquids (GTL) projects for which there is a ready market (box 6).

Greenfield projects are the most costly and challenging of gas investments, since the infrastructure for the full supply chain — gas field production facilities, high pressure pipelines and/or LNG chains and location distribution networks — need to be brought into operation simultaneously. Project risks are also particularly large when the market being supplied is immature and where there are doubts about the creditworthiness of major consumers (IEA 2003b).

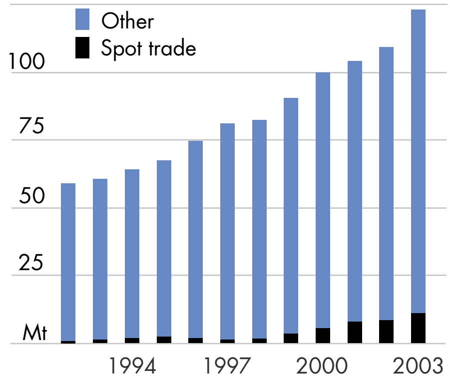
As discussed in chapter 2, there have recently been some projects proceeding without significant sales volumes in place, including MLNG Tiga and Sakhalin 2. However, the large investments and commitments required for the construction of LNG plants, ships and terminals, is likely to prevent the short term market replacing the current framework of long term contracts (Flower and King 2002).

Short term trading

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. The short term LNG market was almost nonexistent until a few years ago, but short term trading began to evolve as sellers sought to utilise spare liquefaction capacity and some buyers found that gas demand increased more quickly than forecast. Short term and spot trades rose to around 11 million tonnes in 2003, equivalent to around 11 per cent of the world LNG market (figure 65).

The main factors driving the short term market include uncommitted production capacity (with some plants built without committing the full volume), additional volumes because of debottlenecking, market demand for additional LNG, such as Korea's need for greater volumes in winter, delays by the Korean government in procuring LNG through long term contracts, and the availability of ships not committed to projects. The main constraint to date on an LNG spot market developing has been a lack of LNG transport capacity, and more recently spare cargoes (EIA 2003b; Suzuki and Morikawa 2003).

65 **World LNG trade, by type of contract**



Prices for short term cargoes are generally set according to the market into which they are sold. The majority of short term and spot trades occur in the Atlantic Basin, where the proximity of the United States and European markets provides buyers and sellers with an opportunity to arbitrage prices and divert LNG cargoes to attract the highest price. In contrast, Asian buyers tend only to import short term and spot cargoes when unexpected situations raise demand or because of delays in signing long term contracts, and thus the price follows rather than drives short term imports (East-West Center 2004).

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 (Flower and King 2002).

Australia

Natural gas reserves

Australia's proven recoverable reserves of natural gas were estimated at 2.5 trillion cubic metres (equivalent to 1.9 billion tonnes of LNG) at the end of 2003. This represents around 19 per cent of proven recoverable reserves in the Asia Pacific region and 1.4 per cent of world gas reserves. Based on proven recoverable reserves, the reserve to production ratio in Australia —

Box 6: **Gas to liquids technology**

Gas to liquids (GTL) technologies are methods of converting natural gas into synthetic petroleum products such as diesel and naphtha and represent an alternative option for commercialising gas resources, including those unable to be piped economically to markets. The process is not new but it has faced a significant cost disadvantage compared with conventional oil products. Interest in GTL production has grown in recent years because of high oil prices and lower GTL production costs. There are currently only two commercial GTL plants in operation — in South Africa and Malaysia — but several other plants are under construction or planned.

Gas to liquids products have several advantages over conventional petroleum products and LNG. GTL products are lower in sulphur and aromatics than conventional petroleum products and have less toxic particle emissions. Products such as GTL diesel can claim a price premium over conventional products because of its higher quality. Unlike LNG, GTL products do not require specialist transport and storage infrastructure. In addition, GTL products have an existing market, supplementing conventional petroleum products, and therefore do not require long term contracts in order to develop new GTL projects.

Despite recent declines, there are still, however, considerable costs involved in GTL production, particularly in capital expenditure. Royal Dutch/Shell is investing US$5 billion into a GTL joint venture with Qatar Petroleum. When fully operational, the Qatar plant should produce 140 thousand barrels a day of synthetic petroleum products. Shell estimates that the production cost of GTL products is 60 per cent higher than LNG.

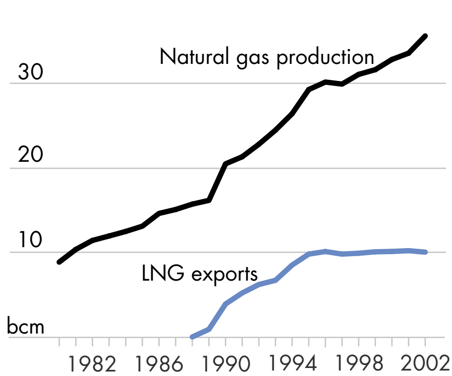
The long term viability of GTL projects is dependant on a stable oil price and the availability of cheap, high quality natural gas. Shell estimates that its Qatar project is economically viable with oil prices in excess of US$20–22 a barrel. The proposed Sasol/Chevron joint venture project in Nigeria is estimated to be viable at prices above US$17 a barrel. This is compared with an average West Texas Intermediate oil price of US$40.64 a barrel for the first ten months of 2004 and ABARE's forecast average price for 2005 of US$41 a barrel. Continued research and development is expected to further reduce GTL production costs, increasing the attractiveness of GTL investments.

There are a number of proposed GTL projects in Australia. These include the Sasol/Chevron joint venture on Barrow Island in Western Australia, the Liquigaz methanol project on the Burrup Peninsula in Western Australia, the Victorian power and liquids project in Latrobe Valley, Victoria, and the Tassie Shoal methanol project in the Timor Sea off the Northern Territory.

Sources: Burg et al. (2004); GTL Resources (2001); Haine et al. (2004); Hill (1998); Shell (2004d); Singleton and Cooper (1997).

the number of years that gas reserves could maintain the current level of production — is approximately 76.9 (BP 2004). This figure is significantly greater if recoverable reserves that have not yet been declared commercially viable are also included, rising to 4.0 trillion cubic metres (Geoscience Australia 2004) or nearly 122 years.

66 **Natural gas production and LNG exports, Australia**



Australia's most significant gas reserves are located off the north coast of Western Australia and in the Timor Sea, north of Australia. These include the Carnarvon, Browse and Bonaparte Basins.

Gas production and exports

Natural gas production in Australia has increased steadily over the past two decades to reach 35.6 billion cubic metres (equivalent to 26.0 million tonnes of LNG) in 2002 (IEA 2003a; figure 66). This represents average annual growth in gas production of around 6.5 per cent since 1980. Much of the recent growth in output has been to fuel domestic gas consumption, with the domestic market absorbing around 70 per cent of Australia's gas production.

Australia also exports LNG. It currently has one LNG liquefaction plant for export purposes — the North West Shelf (NWS) — located at Karratha in Western Australia. The plant commenced operation in 1989 and currently incorporates four trains, with a combined annual LNG production capacity of 11.7 million tonnes (table 57). The fourth train was completed in September 2004, which increased Australia's LNG production capacity by 4.2 million tonnes. LNG from the NWS is marketed through a consortium: North West Shelf Australia

57 **Existing LNG projects, Australia**

Project	Capacity	Trains	Start up
	Mtpa	no.	
North West Shelf	11.7	4	1989
Trains 1, 2	4.4	2	1989
Train 3	2.2	1	1993
Debottlenecking	0.9	–	1995
Train 4	4.2	1	2004

Sources: ALNG (2004), EIA (2003b).

LNG. The consortium consists of six partners with equal shares: BHPBilliton Petroleum, BP Developments Australia, ChevronTexaco Australia, Japan Australia LNG (MIMI), Shell Development (Australia), and the project operator, Woodside Energy.

In 2003, Australia was the fourth largest LNG exporter in the Asia Pacific region and the seventh largest in the world, exporting around 7.7 million tonnes of LNG. This represented 6 per cent of world LNG trade in that year (BP 2004). Australian LNG exports have remained relatively constant since the mid-1990s, reflecting the completion of three trains at the NWS.

Australia's LNG export industry is underpinned by long term supply contracts with Japanese energy utilities of around 11.2 million tonnes a year, including those for NWS Train 4 (table 58). Around 98 per cent of Australia's LNG exports in 2003 were to Japan. Australia also exported small volumes to Korea and Spain (table 59). In the past, Australia has also exported spot cargoes to customers in Turkey and the United States. Korea is expected to

58 Existing mid/long term LNG supply contracts, Australia

Project	To	Importer	Volume	Duration
			Mtpa	
North West Shelf	Japan	Tokyo, Chubu, Kansai **a**, Chugoku and Kyushu Electric Power Companies, Tokyo Gas, Toho Gas, Osaka Gas	7.3	1989–2009
North West Shelf	Korea	KOGAS	0.5	2003–10
North West Shelf	Japan	Osaka Gas	1.0	2004–21
North West Shelf	Japan	Tokyo Gas, Toho Gas	1.4	2004–29
North West Shelf	Japan	Tohoku Electric	0.4	2005–20
North West Shelf	Japan	Kyushu Electric	0.5	2006–26
North West Shelf	Japan	Chubu Electric	0.6	2009–24
North West Shelf	Japan	Shell Eastern LNG	3.7 **b**	2004–09
North West Shelf	China	CNOOC	3.3	2006–31
Darwin LNG	Japan	Tokyo Electric, Tokyo Gas	3.0	2006–22

a Kansai Electric Power Company has extended its contract, to take 0.5 Mt a year from 2009 to 2014, then 0.93 Mt a year until 2023. **b** Over five years, not annually.
Source: ALNG (2004).

increase its volume of Australia's LNG exports from 2004, as the mid term contract between KOGAS and NWS for 0.5 million tonnes a year reaches its full volume.

59 LNG exports, by destination, Australia, 2003

	Mt	%
Japan	7.50	97.6
Korea	0.12	1.6
Spain	0.06	0.8
Total	7.68	100.0

Source: BP (2004).

NWS has also agreed to sell up to 3.7 million tonnes from Train 4 to Shell Eastern LNG between 2004 and 2009, to develop sales outside its core markets, including to India. Actual volumes will depend on annual contractual commitments to long term customers in core markets. Australia will also begin supplying China's Guangdong province from mid-2006, when the contract to supply 3.3 million tonnes of LNG a year for 25 years is expected to commence.

Outlook for LNG supply

Australia's LNG exports are expected to grow rapidly in the coming decade on the basis of new liquefaction capacity under construction and proposed.

There is one LNG project in Australia currently under construction: the Darwin LNG plant (table 60). The Darwin LNG plant, which is part of the Bayu-Undan project in the Australia-East Timor Joint Petroleum Development Area, is expected to commence operation in early 2006 and will have an annual LNG production capacity of 3.5 million tonnes. The plant is located at Wickam Point, near Darwin, and operated by ConocoPhillips. The plant will supply Tokyo Electric Power Company and Tokyo Gas with 3.0 million tonnes a year for 17 years from 2006. On completion of this project, Australia is expected to have an annual LNG supply capacity of 15.2 million tonnes.

Proposed projects

There are also several proposed LNG export projects in Australia over the outlook period. The NWS is considering a fifth train of 4.2 million tonnes a year, currently planned to commence operations from 2008. A final investment decision on the fifth train is anticipated by late 2004 or early 2005, and will depend largely on securing future LNG markets, including new sales and contract renewals with existing customers. It is expected that the majority of the NWS supply to Guangdong could eventually be sourced from the fifth train.

60 LNG projects under construction and proposed, Australia

Project	Capacity	Trains	New project	Start up
	Mtpa	no.	Y/N	
Under construction				
Darwin LNG	3.5	1	Y	2006
Total	3.5	1		
Proposed				
North West Shelf Train 5	4.2	1	N	2008
Gorgon	10.0	2	Y	2008
Sunrise	5.3	1	Y	2010
Tassie Shoal	2.5	1	Y	2010
Scarborough	6.0	1	Y	2010
Browse	10.0	–	Y	2011
Total	38.0	6		

Sources: ALNG (2004), EIA (2003b), ConocoPhillips (2004), Woodside (2003), Methanol Australia (2004), BHP Billiton (2004), Gorgon (2004).

Also currently scheduled to commence operations in late 2008 is the Gorgon LNG project. The liquefaction facility, to be located on Barrow Island off the Western Australian coast, received in principle approval from the state government in late 2003. The project is expected to consist of two trains with a total annual liquefaction capacity of 10 million tonnes. To date, Gorgon has an agreement to sell 80 to 100 million tonnes (up to 4 million tonnes a year) of LNG to China's CNOOC for 25 years from 2008. Gorgon also has agreements to supply ChevronTexaco Overseas Petroleum with 2 million tonnes of LNG annually from 2008 for the potential north American west coast market, and with Shell Gas and Power for 2 million tonnes a year over 20 years for its proposed import terminal in Baja California.

The Greater Sunrise project in the Timor Sea is scheduled to be operational by the end of the decade. Several locations for the 5.3 million tonne a year liquefaction plant are currently under consideration, including an onshore plant in northern Australia, a floating LNG facility, and a plant in East Timor. The project is currently targeted to commence operations by 2010. However, issues surrounding the maritime border and distribution of royalties between East Timor and Australia still need to be resolved before the project can proceed.

Methanol Australia received environmental approval from the Australian Government in May 2004 to construct and operate an offshore LNG plant on Tassie Shoal in the Timor Sea, adjacent to the planned Tassie Shoal Methanol Project. The annual liquefaction capacity of the plant will be 2.5 million tonnes, with construction proposed to commence in 2007. First LNG production is scheduled for 2010.

BHP Billiton is currently undertaking a pre-feasibility study of its proposed Scarborough LNG plant and a preferred site was announced near Onslow in Western Australia in September 2004. Recent announcements suggest the LNG project will comprise a single train with capacity of 6.0 million tonnes a year. A suggested start up date is 2010. The project is being considered to supply LNG to the company's proposed Cabrillo Port import terminal off the Californian coast.

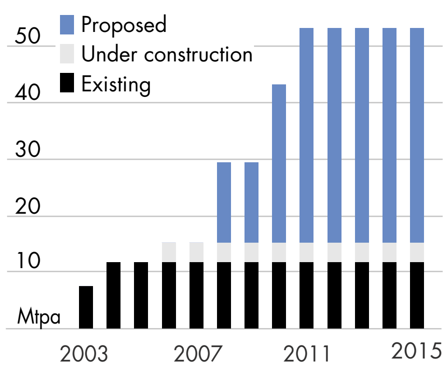
Further LNG projects in Australia are proposed in the period post 2010. The Browse LNG project is to be based on the Scott Reef and Brecknock gas fields in the Browse Basin. A possible start date for the project is 2011, with the reserves able to support a 10 million tonne a year LNG plant.

If all the projects discussed above come on line as planned, Australia's annual LNG supply capacity could rise to 53.2 million tonnes by the end of 2011 (figure 67). The extent to which this LNG export capacity potential is realised and the ultimate timing of projects will depend significantly on securing long term supply contracts to underpin investment.

Other issues

The Australian LNG industry has received encouragement from the Australian Government in view of the contribution of LNG projects to industry and the wider economy. In 2000, the Australian Government and the Australian Petroleum Production and Exploration Association jointly developed an LNG Action Agenda (box 7). The Agenda committed the government to developing policies that would

67 Potential LNG supply capacity, Australia



Box 7: **LNG Action Agenda 2000**

In October 2000, the Australian government and the Australian Petroleum Production and Exploration Association (APPEA) jointly developed an LNG Action Agenda for the Australian LNG industry. This agenda committed the government to developing policies that enhanced the competitiveness of the LNG industry and removed or mitigated impediments to growth. These included removing excess regulation, improving access to capital equipment, and certainty to industry regarding Australia's greenhouse gas emission reduction targets.

In identifying the need for an LNG Action Agenda, it was acknowledged that:

- the industry is important to Australia's economy;
- there are significant prospects for growth;
- the industry is a driver of growth in other sectors;
- a whole of government approach is needed to address impediments; and
- there is potential for improving the international competitiveness of the industry by taking certain actions.

The objectives identified for Australia's LNG industry in the Agenda include to:

- be the preferred supplier for new LNG demand;
- realise its potential within the next twenty years to be one of Australia's largest export earners; and
- expand its share of the Asian market from the current level of 10 per cent to 30 per cent by 2020.

Among others, the Agenda covered issues surrounding Australia's existing domestic company tax rate, which exceeded the average company tax of its competitors by around 10 per cent, and Australia's larger than average write-off period for depreciation. The hindrances associated with particular import tariffs were also acknowledged in the Agenda. An important action in this context has been to introduce a new by law that allows LNG projects with initial capital expenditure of at least A$50 million to obtain duty free imports of capital equipment unavailable in Australia. A further achievement was the resolution of fiscal and regulatory uncertainties relating to the processing of gas in the Australia–East Timor Joint Petroleum Development Area to enable the Bayu Undan project to proceed. The government has also been working with industry to secure long term LNG supply contracts in Asia Pacific markets.

Sources: DITR (2004); DISR (2000).

enhance the competitiveness of the industry, including removing excess regulation and facilitating duty free imports of some capital equipment. The government has also played a supportive role in the marketing of LNG in some countries, including emphasising Australia's political stability and supply reliability.

Indonesia

Natural gas reserves

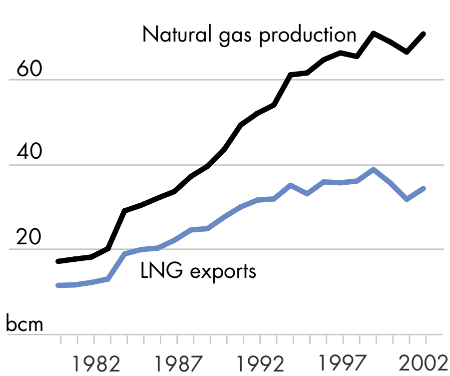
Indonesia has an estimated 2.6 trillion cubic metres (equivalent to 1.9 billion tonnes of LNG) of proven recoverable gas reserves at the end of 2003. This is equal to 19 per cent of reserves in Asia Pacific region and 1.5 per cent of world reserves. The current reserve to production ratio in Indonesia is 35.2 years (BP 2004). Indonesian gas reserves are located around the Arun field in Aceh, around the Badak field in east Kalimantan, around Java and Papua, and Natuna in the South China Sea (EIA 2004d).

Gas production and exports

Indonesia's production of natural gas was 70.8 billion cubic metres (equivalent to 51.7 million tonnes of LNG) in 2002 (IEA 2003a; figure 68). Gas production has generally grown strongly over the past two decades, at an average annual rate of 6.7 per cent. Much of the growth in recent years has supplied rising domestic gas consumption, with gas rising in importance in Indonesia's primary energy fuel mix. Natural gas supply to the domestic market comprises around half of Indonesia's total output. Indonesia also exports significant volumes of natural gas, both LNG and via international pipelines. LNG accounted for close to 96 per cent of all Indonesian gas exports in 2002, with the remainder being pipeline exports to Singapore and Malaysia.

Indonesia currently has two LNG export projects, with a combined

68 Natural gas production and LNG exports, Indonesia



annual LNG supply capacity of around 29.4 million tonnes (table 61). Indonesia's largest LNG project is Bontang, which began operations in 1977. It has undergone several expansions since its inception, and now incorporates eight trains with a total production capacity of around 22.6 million tonnes a year.

61 Existing LNG projects, Indonesia

Project	Capacity	Trains	Start up
	Mtpa	no.	
Bontang	22.6	8	1977
Arun	6.8	4	1978
Total	29.4	12	

Source: EIA (2003b).

Indonesia's other LNG project is the Arun LNG plant, which began operation in 1978. Annual production capacity peaked at around 11.5 million tonnes, however, two of its six trains were decommissioned in 2000 in response to depleting reserves. The four operating trains currently produce around 6.8 million tonnes of LNG a year to meet existing contracts. As supply contracts with Arun expire in the next few years, it is expected that production from the facility will be discontinued.

Indonesia is currently the largest LNG supplier in the world. In 2003, Indonesia exported 26.0 million tonnes of LNG, representing 21 per cent of world LNG trade (BP 2004). The lower volume of exports since 1999 reflects the decomissioning of the two Arun trains in 2000, followed by a 7 month disruption to Arun's production facilities in 2001 as a result of political unrest in Aceh province.

The majority of Indonesian LNG exports are to Japan, which accounted for 67 per cent of trade in 2003 (table 62). The remainder of Indonesian exports in that year were to Korea and Chinese Taipei, accounting for 19 per cent and 13 per cent of Indonesia's LNG trade respectively. Trade flows reflect the long term LNG supply contracts that Indonesia has with Japanese, Korean and Chinese Taipei energy utilities. In 2004, annual long term contract volumes were close to 27 million tonnes (table 63). Included in the figure are several renewals of Japanese contracts with Bontang for around

62 LNG exports, by destination, Indonesia, 2003

	Mt	%
Japan	17.56	67.4
Korea	5.06	19.4
Chinese Taipei	3.42	13.1
Total	26.03	100.0

Source: BP (2004).

12 million tonnes of LNG a year until 2010-11. Tohoku Electric Power Company has also extended its Arun contract for 0.83 million tonnes a year for five years to 2009.

Outlook for LNG supply

As discussed earlier, the production capacity reported for Arun reflects contractual volumes. Arun gas reserves are reported to be around 70 per cent depleted, and are likely to be completely exhausted by 2015 (FACTS Inc. 2003b). It is expected that further Arun trains will be decommissioned as LNG sales contracts expire after 2004, 2007 and 2009. The plant is expected to be completely mothballed by around 2010.

Proposed projects

Despite expected declines in available LNG production capacity at Arun, supply from Indonesia could increase over the period to 2015 with three LNG export projects proposed (table 64). A ninth train at Bontang — Bontang I — has been proposed for several years. The 3.0 million tonne a year train is scheduled to begin operations in 2007 and would expand annual LNG production capacity at Bontang to more than 25 million tonnes. It is under-

63 Existing long term LNG supply contracts, Indonesia

Project	To	Importer	Volume Mtpa	Duration
Arun	Japan	Tokyo and Tohoku Electric Power Companies	3.51	1984–2004
Arun	Korea	KOGAS	2.30	1986–2007
Arun	Japan	Tohoku Electric Power Company	0.83	2005–09
Bontang	Chinese Taipei	CPC	1.58	1990–2009
Bontang	Japan	Tokyo Gas, Osaka Gas, Toho Gas	2.31	1994–2013
Bontang	Korea	KOGAS	2.00	1994–2014
Bontang	Japan	Osaka Gas, Hiroshima Gas, Nihon Gas	0.39	1996–2015
Bontang	Korea	KOGAS	1.00	1998–2017
Bontang	Chinese Taipei	CPC	1.84	1998–2017
Bontang	Japan	Chubu, Kansai and Kyushu Electric Power Companies, Toho Gas, Osaka Gas, Nippon Steel	8.45	2000–10
Bontang	Japan	Toho Gas, Osaka Gas	3.52	2003–11

Sources: Petroleum Economist (2003); Suzuki and Morikawa (2003).

64 LNG projects under construction and proposed, Indonesia

Project	Capacity	Trains	New project	Start up
	Mtpa	no.	Y/N	
Proposed				
Bontang Train I	3.0	1	N	2007
Tangguh	7.0	2	Y	2008
Donggi	6.6	2	Y	2008
Total	16.6	5		

Sources: EIA (2003b); Petroleum Economist (2003).

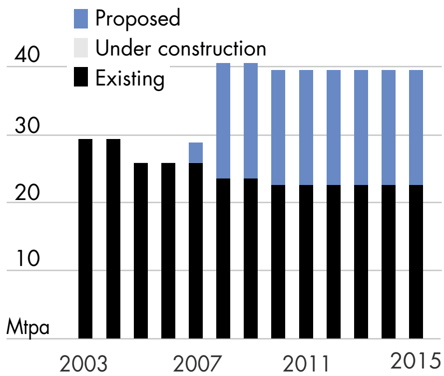
stood that front end engineering and design has been competed and construction contracts have been awarded. However, the project is waiting to finalise LNG sales contracts before proceeding (Taylor Sen 2003b).

Expected on line from 2008 is the Tangguh project in Papua. Annual LNG production capacity at Tangguh will be 7.0 million tonnes from two liquefaction trains, although a third train has recently been discussed. Tangguh has recently signed several sales and purchase agreements. These include to supply 2.6 million tonnes of LNG a year for 25 years to CNOOC for Fujian province in China from 2007, and around 1.1 million tonnes of LNG a year to POSCO and SK Power in Korea from 2005-06. Interim volumes are expected to be sourced from Bontang and elsewhere until Tangguh becomes operational. Tangguh has also signed a 15 year contract with Sempra Energy for 3.7 million tonnes of LNG annually to the north American west coast market starting in 2007, which also provides for an additional five years LNG supply from other Indonesian sources.

The other proposed LNG export project in Indonesia over the outlook period is Donggi in central Sulawesi. The Donggi project is currently planned to come on line in 2008 with an expected capacity of around 6.6 million tonnes a year. Donggi does not yet have sales contracts in place. The project had a memorandum of understanding to supply 6 million tonnes of LNG a year for 20 years to the Tijuana import terminal in Baja California, however, the proposed terminal project has since been canceled.

If the above three projects come on line as currently planned, Indonesia could have an annual LNG production capacity of more than 39 million tonnes by 2010 (figure 69). As with other projects in the region, however, the realisation of each of the projects will depend to a significant extent on securing long term supply contracts, and may vary from that shown here.

69 **Potential LNG supply capacity, Indonesia**



Other issues

Investment in Indonesia's energy sector has slowed in recent years, partly as a result of uncertainty related to the 2001 Oil and Gas Law. Indonesian LNG production, exports and sales contracts were previously managed by the state oil and gas monopoly Pertamina. Under the oil and gas law, Pertamina now has no involvement in the gas sector outside its own acreage, unless it is directed to do so by BP Migas, the new implementing body for oil and gas upstream activities. Pertamina has therefore lost its monopoly as the state's representative in negotiations with foreign parties and this has created some uncertainty over its role in LNG marketing. However, Pertamina was recently appointed the sole seller of Indonesian LNG to Japan, Chinese Taipei and Korea and will sign contracts on behalf of Indonesia (Energy Argus 2004d).

Indonesia must also overcome issues related to perceived resource and political insecurity. Disruptions to LNG production occurred in 2001 when the Arun LNG complex was closed for seven months in response to security concerns in Aceh province. This had a direct impact on the supply of LNG to Korea and Japan, which were required to source alternative LNG supplies for several months. Ongoing security concerns in the region continue to increase the perceived investment and supply risks in Indonesia's LNG industry. During 2004, Indonesia has also had difficulties in meeting export cargo requirements from Bontang and Arun, adding to supply reliability concerns.

Indonesia also has domestic gas shortages in some regions, including Java, as a result of inadequate infrastructure and premature resource exhaustion. One option being considered is an LNG receiving terminal, possibly in East and/or West Java, by the end of the decade. LNG could potentially be sourced from some of the proposed export projects, which could limit volumes available for exports (Platts 2004g; Aspermont 2004d).

Malaysia

Natural gas reserves

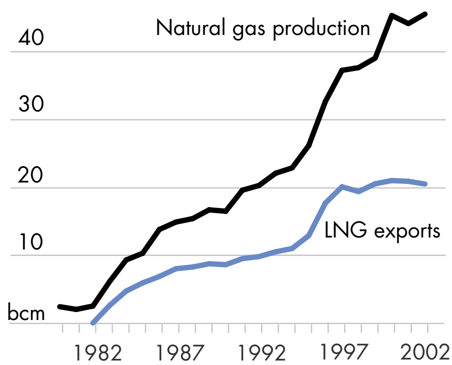
Malaysia's proven recoverable natural gas reserves were estimated at 2.4 trillion cubic metres (equivalent to 1.8 billion tonnes of LNG) at the end of 2003. This represents around 18 per cent of proven recoverable reserves in the Asia Pacific region and 1.4 per cent of world gas reserves. The reserve to production ratio in Malaysia is approximately 45.0 years (BP 2004). Malaysia's natural gas resources are mostly located in offshore Sarawak, as well as off the peninsular of Malaysia and Sabah.

Gas production and exports

Natural gas production in Malaysia was 45.6 billion cubic metres (equivalent to 33.3 million tonnes of LNG) in 2002 (IEA 2003a; figure 70). Malaysia's gas production has grown strongly from 2.4 billion cubic metres in 1980, at an average annual rate of 14.3 per cent. Natural gas supply to the domestic market comprises about 60 per cent of Malaysia's total production and gas accounts for more than three quarters of primary energy supply in Malaysia (IEA 2004b). The government has recently implemented policies to reduce the dependence on natural gas, including through the development of coal fired power plants.

Malaysia also exports significant volumes of natural gas. LNG trade accounted for 99 per cent of Malaysia's natural gas exports in 2002, while the remaining gas was exported via pipeline to Singapore. Malaysia commenced LNG exports in 1983 and three liquefaction terminals have been developed at the Bintulu LNG complex in Sarawak: Satu (I), Dua (II) and Tiga (III). The complex has an annual LNG export capacity of 22.2 million tonnes (table 65). Production and exports of LNG are the responsibility of Petronas,

70 Natural gas production and LNG exports, Malaysia



the national oil and gas company of Malaysia, and the company owns the majority share in MLNG I, II and III.

65 Existing LNG projects, Malaysia

Project	Capacity	Trains	Start up
	Mtpa	no.	
MLNG I (Satu)	7.6	3	1983
MLNG II (Dua)	7.8	3	1996
MLNG III (Tiga)	6.8	2	2003
Total	22.2	8	

Source: EIA (2003b).

Prior to 2003, Malaysia had six LNG trains with an annual capacity of 15.4 million tonnes. A seventh train with a capacity of 3.4 million tonnes a year commenced production in March 2003. In August 2003, the train ceased production as the result of a fire, restarting in March 2004. Train 8, which was unaffected by the fire, came on line in October 2003. MLNG III differed somewhat from other LNG projects in the region in that it came on line with few long term sales agreements in place, although it has since secured additional contracts.

Malaysia is the second largest LNG supplier in the Asia Pacific region, and the third largest in the world. Malaysia exported 17.1 million tonnes of LNG in 2003, around 13.9 per cent of global LNG trade. Exports are expected to increase in 2004 as supply from MLNG III reaches full capacity. Malaysia's most significant LNG trade partnership is with Japan, which imported 71 per cent of Malaysian LNG in 2003 (table 66). Korea and Chinese Taipei accounted for most of the remainder, while Malaysia also exported a small quantity of LNG on the spot market to the United States in 2003.

The majority of Malaysia's LNG sales are through long term contracts with power and gas utilities in Japan, Korea and Chinese Taipei (table 67). These include 15 year contract renewals with both TEPCO and Tokyo Gas for a combined supply of 7.4 million tonnes a year between 2003–18.

66 LNG exports, by destination, Malaysia, 2003

	Mt	%
Japan	12.21	71.5
Korea	2.77	16.2
Chinese Taipei	2.04	12.0
United States	0.06	0.3
Total	17.07	100.0

Source: BP (2004).

Outlook for LNG supply

Malaysia has one proposed LNG project over the period to 2015, MLNG IV, an extension of the Bintulu plant by an additional 3.4 million tonnes a year (table 68). However, there has been little recent

67 Existing mid/long term LNG supply contracts, Malaysia

Project	To	Importer	Volume	Duration
			Mtpa	
MLNG I	Japan	Tepco, Tokyo Gas	7.4	2003–18
MLNG I	Japan	Saibu Gas	0.36	1993–13
MLNG II	Japan	Tokyo Gas Osaka Gas, Toho Gas, Kansai Electric Power Company	2.1	1995–2015
MLNGII	Chinese Taipei	CPC	2.25	1995–2015
MLNG II	Japan	Tohoku Electric, Shizuoku Gas	0.95	1996–2016
MLNG II	Japan	Sendai City	0.15	1997–2017
MLNG II	Korea	KOGAS	2.3	1995–2015
MLNG III	Korea	KOGAS	2.0	2003–10
MLNG III	Japan	JAPEX	0.48	2003–23
MLNG III	Japan	Tokyo Gas, Osaka Gas and Toho Gas	1.6	2004–24
MLNG III	Japan	Tohoku Electric Power Company	0.9	2005–25

Source: Petroleum Economist (2003).

promotion of the project. The company stated early in 2004 that the project was on hold and that the timing of the capacity expansion will depend on the development of both traditional and new markets (Aspermont 2004e). For this reason, it has been excluded from the supply projections in this study, and Malaysia's LNG supply capacity is assumed to remain at 22.2 million tonnes a year out to 2015 (figure 71).

In addition, the Malaysian government has been promoting Malaysia as a potential supply hub for the Trans-ASEAN Gas Pipeline. Pipelines connecting Malaysia with Indonesia and Singapore are currently in operation, while connections to Thailand, Vietnam and the Philippines are planned or under discussion. This pipeline project is discussed in more detail in chapter 6.

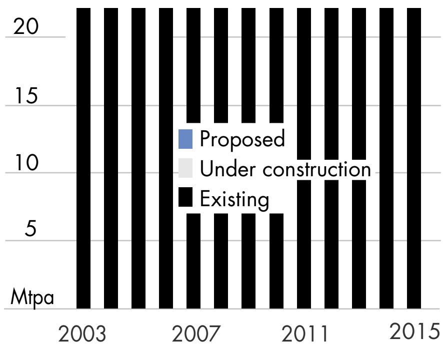
68 LNG projects under construction and proposed, Malaysia

Project	Capacity	Trains	New project	Start up
	Mtpa	no.	Y/N	
Proposed				
MLNG IV	3.4	1	N	–

Source: Petroleum Economist (2003).

Such a move could see Malaysia shift its focus to increasing pipeline gas exports rather than developing additional LNG projects.

71 **Potential LNG supply capacity, Malaysia**



Brunei

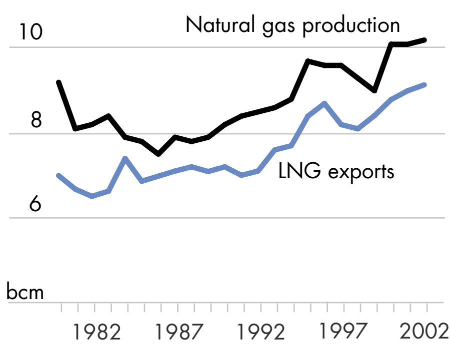
Natural gas reserves

Proven recoverable reserves of natural gas in Brunei were estimated at 0.4 trillion cubic metres (equivalent to 0.3 billion tonnes of LNG) at the end of 2003. This represents around 3 per cent of proven recoverable reserves in the Asia Pacific region and 0.2 per cent of world reserves. The reserve to production ratio in Brunei is approximately 28.3 years (BP 2004). Brunei's natural gas reserves are mostly located off the coast of Lumut.

Gas production and exports

Total natural gas production in Brunei was 10.2 billion cubic metres (equivalent to 7.4 million tonnes of LNG) in 2002 (IEA 2003a; figure 72). Gas production has fluctuated in Brunei over the past two decades, rising at an average annual rate of 0.4 per cent. Production declined noticeably in the late 1990s, as a result of lower domestic consumption and exports stemming from the Asian economic downturn. Natural gas supply to the domestic market comprises about 15 per cent of Brunei's total production, although domestic consumption has been falling in recent years in response to attempts by the Brunei government to diversify the country's energy mix away from gas. More than two thirds of Brunei's primary

72 **Natural gas production and LNG exports, Brunei**



energy consumption was natural gas in 2002 (IEA 2004b).

Brunei commenced exporting LNG in 1972 and currently has one LNG plant at Lumut: Brunei LNG (BLNG). The Brunei government holds half the interests in the project. BLNG has five trains, with a total production capacity of around 7.2 million tonnes a year (table 69). In 1993, BLNG underwent debottlenecking to increase its capacity to current levels.

69 Existing LNG projects, Brunei

Project	Capacity	Trains	Start up
	Mtpa	no.	
Brunei LNG	7.2	5	1972

Source: EIA (2003b).

70 LNG exports, by destination, Brunei, 2003

	Mt	%
Japan	6.52	92.3
Korea	0.54	7.7
Total	7.06	100.0

Source: BP (2004).

Brunei is currently the fourth largest LNG supplier in the Asia Pacific region and exported 7.1 million tonnes of LNG in 2003 (BP 2004). This constituted around 5.7 per cent of world LNG trade, and 8.5 per cent of Asia Pacific trade. Brunei's most significant LNG trade relationship is with Japan, which imported 92 per cent of Brunei's LNG exports in 2003 (table 70). Korea accounted for the remaining LNG exports in that year. Brunei has long term sales contracts with Japan and Korea for around 6.7 million tonnes a year, both of which are due to expire in 2013 (table 71).

Outlook for LNG supply

There is one proposed LNG project in Brunei over the period to 2015, which is an extension to the existing BLNG facility. A sixth train is planned, which

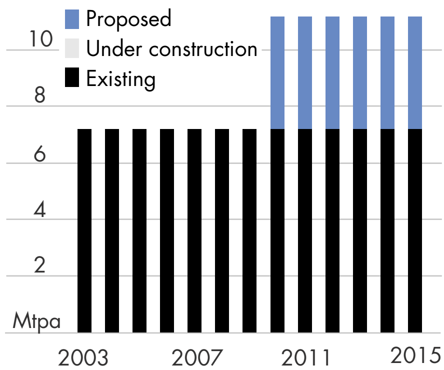
71 Existing long term LNG supply contracts, Brunei

Project	To	Importer	Volume	Duration
			Mtpa	
Brunei LNG	Japan	Tepco, Tokyo Gas, Osaka Gas	6.01	1993–2013
Brunei LNG	Korea	KOGAS	0.70	1997–2013
Total			6.71	

Source: BLNG (2004).

would increase BLNG's annual LNG supply capacity by 4.0 million tonnes to 11.2 million tonnes (figure 73; table 72). The company has scheduled the project to be operational by 2010, two years later than originally planned (BLNG 2004; Petroleum Unit 2003). Issues relating to a disagreement over the ownership of the acreage between Brunei and Malaysia, as well as further exploration to consolidate reserves and securing LNG markets, could affect the realisation of the project (EIA 2003d).

73 Potential LNG supply capacity, Brunei



In 2013, Brunei also has plans to modernise its existing LNG plant to maintain production capacity and extend its operating life for a further 20 years to 2033 (BLNG 2004).

72 LNG projects under construction and proposed, Brunei

Project	Capacity	Trains	New project	Start up
	Mtpa	no.	Y/N	
Proposed				
BLNG Train 6	4.0	1	N	2010

Sources: BLNG (2004); Petroleum Unit (2003).

Alaska, United States

Natural gas reserves

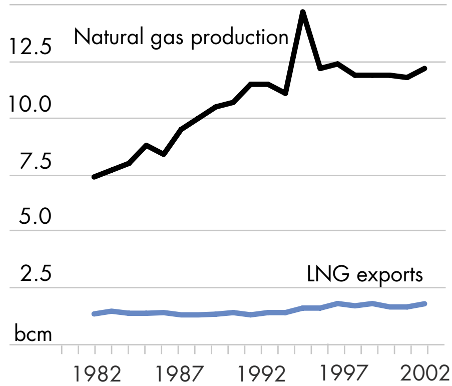
Proved recoverable reserves in the United States were 5.2 trillion cubic metres at the end of 2003. Of this total, around 237 billion cubic metres or 5 per cent are located in the state of Alaska (OGJ 2003; EIA 2004a). Alaskan gas reserves are equal to around 0.1 per cent of the world's total proven recoverable reserves. The reserve to production ratio in Alaska is around 19.5 years.

Gas production and exports

Natural gas production in Alaska was 12.2 billion cubic metres (equivalent to 8.9 million tonnes of LNG) in 2001 (EIA 2004a; figure 74). Production has grown at an average annual rate of 2.7 per cent since 1982, although has been relatively flat since the mid-1990s. The majority of gas produced is used locally within the state, while around 15 per cent is exported as LNG.

Alaska began exporting LNG in 1969 and has one LNG plant, at Kenai, with an annual supply capacity of 1.4 million tonnes. Reflecting the age of the plant, this total capacity is produced from two trains of equal size (table 73).

74 Natural gas production and LNG exports, Alaska



73 Existing LNG projects, Alaska

Project	Capacity	Trains	Start up
	Mtpa	no.	
Kenai	1.4	2	1969

Source: EIA (2003b).

Alaska exported 1.2 million tonnes of LNG in 2003, which accounted for 1.4 per cent of exports to the Asia Pacific market and 1.0 per cent of world LNG trade (BP 2004). All of Alaska's LNG exports were to Japan. Alaska has existing LNG contracts with TEPCO and Tokyo Gas (for a combined 1.23 million tonnes a year) that are due to expire in 2004 (table 74). Both

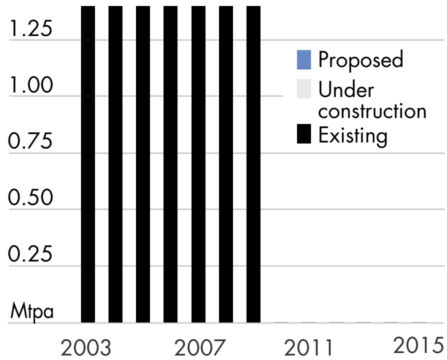
74 Existing long term LNG supply contracts, Alaska

Project	To	Importer	Volume	Duration
			Mtpa	
Kenai	Japan	Tepco, Tokyo Gas	1.23	1989–2004

Source: Suzuki and Morikawa (2003).

contracts have an extension clause for an additional five years of supply to 2009, however, it is not yet known if the extensions will proceed.

75 **Potential LNG supply capacity, Alaska**



Outlook for LNG supply

There is some uncertainty about the future of LNG exports from Alaska. It has been reported that there are some concerns that remaining reserves are insufficient for a long term extension of the supply contracts between Alaska and Japan. In this study, it is assumed that Kenai discontinues production after fulfilling possible contractual obligations in 2009 (figure 75).

For several years there has also been some discussion of using gas from the Alaskan North Slope for LNG supply. Yukon Pacific has proposed a 7 million tonne a year liquefaction plant at Port Valdez, to be supplied with natural gas via a proposed pipeline from the North Slope (table 75). The project was first approved in 1995, and in May 2004 Yukon Pacific was granted a third extension by the Federal Energy Regulatory Commission to build an LNG plant and related facilities in Alaska. The latest order gives until May 2007 for work to begin on the project (Platts 2004h).

The project has recently shown some progress, with Crystal Energy and the Alaska Gasline Port Authority (AGPA) signing a memorandum of understanding to negotiate the delivery of around 6 million tonnes of LNG a year from Alaska for 20 years to a planned receiving terminal on the west coast

75 **LNG projects under construction and proposed, Alaska**

Project	Capacity	Trains	New project	Start up
	Mtpa	no.	Y/N	
Proposed				
North Slope	7.0	–	Y	–

Sources: EIA (2003b).

of California. AGPA has been formed as a municipal port authority to develop and deliver gas from Alaska's North Slope to energy markets in the Pacific region (OGJ 2004). The Authority reportedly plans to complete a feasibility study of the LNG supply project during 2004 (Platts 2004i).

Despite the proximity of the project to potential north American west coast markets, it is believed that there are some environmental concerns regarding the development of the proposed pipeline, which could prevent the project from proceeding as planned. There are also proposals to deliver North Slope gas via a direct pipeline from Alaska to the United States through Canada (Rojey and Chabrelie 2003). In view of this uncertainty, the North Slope LNG proposal is not included in Asia Pacific supply projections in the study.

Qatar

Natural gas reserves

Qatar has the third largest natural gas reserves in the world and the largest reserves of all existing LNG exporters. Proven recoverable reserves of natural gas in Qatar are estimated to be 25.8 trillion cubic metres (equivalent to 18.8 billion tonnes of LNG) at the end of 2003. This represents more than one third of proven recoverable gas reserves in the Middle East and 15 per cent of world reserves. Based on proven recoverable reserves, the reserve to production ratio in Qatar is more than one hundred years (BP 2004). Most of Qatar's natural gas is located in the offshore North Field, which is the largest known non-associated natural gas field in the world.

Gas production and exports

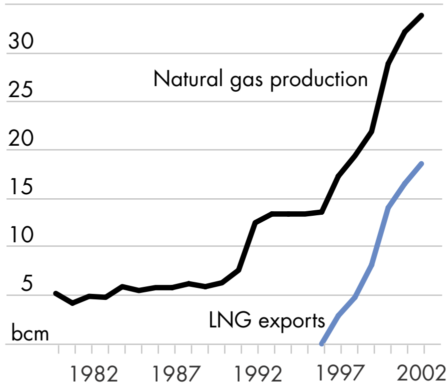
While natural gas production in Qatar remained relatively flat during the 1980s, output has nearly tripled since 1990 to reach 33.9 billion cubic metres (equivalent to 24.7 million tonnes of LNG) in 2002 (IEA 2003a; figure 76). Around half of Qatari natural gas production is used domestically, with much of the electricity sector fired by natural gas.

Much of the recent growth in natural gas production, however, has been for export as LNG. Since it began exporting LNG in late 1996, Qatar has emerged as one of the world's leading suppliers of LNG, particularly to the Asia Pacific region. Qatar currently has two LNG exporters — the Qatar LNG Company (Qatargas) and the Ras Laffan LNG Company (RasGas) —

with a combined annual capacity of 19.6 million tonnes from two liquefaction facilities. Both plants are located at Ras Laffan.

The first Qatari LNG project to begin operations was Qatargas. The Qatargas plant commenced LNG production from trains 1 and 2 in late 1996, while a third train was commissioned in 1998 (table 76). Following debottlenecking in late 2003, the annual production capacity of the facility rose from 7.7 million tonnes to 8.3 million tonnes.

76 **Natural gas production and LNG exports, Qatar**



RasGas commenced operations in 1999, while the second train came on line in 2000, raising its annual supply capacity to 6.6 million tonnes. Under a second phase, RasGas II was established and a third train, operated by RasGas II, was commissioned in early 2004 with an annual capacity of 4.7 million tonnes. This brings total RasGas production capacity to around 11.3 million tonnes a year.

Qatar exported 14.0 million tonnes of LNG in 2003, the fourth largest supplier in the world. This represents around 11.4 per cent of world LNG trade, and 14.9 per cent of trade to the Asia Pacific region. Most of Qatar's exports are to customers in Japan and Korea, which together accounted for 88 per cent of LNG exports from Qatar in 2003 (table 77). Qatar also exported small volumes to Spain and the United States.

This pattern of trade reflects existing long term supply contracts between Qatargas and Japanese utilities and RasGas and Korea

76 **Existing LNG projects, Qatar**

Project	Capacity	Trains	Start up
	Mtpa	no.	
Qatargas	8.3	3	1996
Trains 1,2,3	7.7	3	1996
Debottlenecking	0.6	–	2003
RasGas	11.3	3	1999
RasGas I Train 1	3.3	1	1999
RasGas I Train 2	3.3	1	2000
RasGas II Train 3	4.7	1	2004
Total	19.6	6	

Sources: EIA (2003b); FACTS Inc. (2004a, 2003a).

(table 78). RasGas also began exporting LNG to India in early 2004 under a long term contract, which is sourced from the third train. The first phase of the Indian contract is for 5 million tonnes of LNG a year, with provision to rise to 7.5 million tonnes a year upon completion of a further terminal in India.

77 LNG exports, by destination, Qatar, 2003

	Mt	%
Japan	6.61	47.2
Korea	5.75	41.1
Spain	1.37	9.7
United States	0.28	2.0
Total	14.01	100.0

Source: BP (2004).

Qatar's first long term supply contract with an Atlantic market buyer (between RasGas and ENI Spain) also commenced in 2004, while Qatargas also has some existing mid term contracts with Gas Natural Group in Spain, recently extended until 2012 (Qatargas 2004).

Outlook for LNG supply

Qatar is expected to continue to expand its LNG supply capacity, with several projects under construction and planned. This reflects the surge in investment in LNG projects in Qatar in response to the government's policy of economic diversification (EIA 2003e). The Qatari government has recently announced plans to treble its annual production to 60 million tonnes of LNG by the end of the decade, in order to capitalise on its large gas reserves and low upstream production costs (Aspermont 2004f).

78 Existing long term LNG supply contracts, Qatar

Project	To	Importer	Volume	Duration
			Mtpa	
Qatargas	Japan	Chubu Electric Power Company	4.0	1997–2021
Qatargas	Japan	Tokyo Gas, Osaka Gas	0.7	1998–2021
Qatargas	Japan	Tokyo, Tohoku, Kansai and Chugoku Electric Power Companies	1.1	1999–2021
Qatargas	Japan	Toho Gas	0.2	2000–21
RasGas	Korea	KOGAS	4.8	1999–2024
RasGas	India	Petronet LNG	5.0	2004–24
RasGas	RasGas	ENI Spain	0.7	2004–24

Sources: Suzuki and Morikawa (2003); FACTS Inc. (2003).

Projects in Qatar currently under construction include the RasGas II fourth train, due on line from 2005 (table 79). This will raise production capacity at RasGas by 4.7 million tonnes to 16.0 million tonnes a year. It is expected that much of the capacity from the fourth train will be used to supply European markets, with long term contracts between RasGas, Spain and Italy scheduled to begin supply in 2005.

Proposed projects

Other expected capacity additions in the short term include the continuation of debottlenecking at Qatargas, to increase the capacity of the remaining two trains each by 0.6 million tonnes a year. This is expected to be undertaken in late 2004 and 2005, and will raise total annual capacity to 9.5 million tonnes at Qatargas. The additional volumes from the debottlenecking capacity are expected to supply a long term contract with Gas Natural Group of Spain for 1.5 million tonnes a year from 2005.

Other planned projects over the period to 2015 include Qatargas II, which will comprise two trains, each with an annual capacity of 7.8 million tonnes. LNG sales are scheduled to commence from the first train in late 2007, with train two commencing in 2009. This project is targeted to supply European

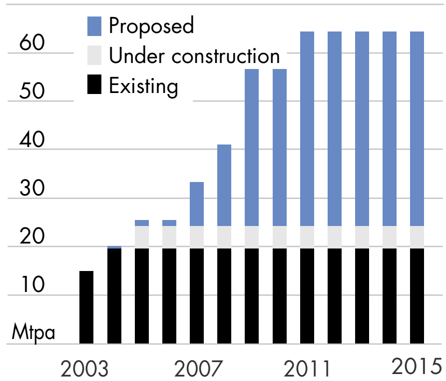
79 LNG projects under construction and proposed, Qatar

Project	Capacity	Trains	New project	Start up
	Mtpa	no.	Y/N	
Under construction				
RasGas II Train 4 **a**	4.7	1	N	2005
Proposed				
Qatargas debottleneck **a**	1.2	–	N	2004-05
Qatargas II **a**	15.6	2	Y	2007
Train 1	7.8	1	–	2007
Train 2	7.8	1	–	2008-09
Qatargas III **b**	7.8	1	Y	2008-09
RasGas II **b**	15.6	2	N	2008-09
Train 5	7.8	1	–	2008-09
Train 6	7.8	1	–	2011-12
Total	40.2	5		

a To European markets. **b** To US markets.
Sources: QatarGas (2004); EIA (2003b); FACTS Inc. (2003a); Platts (2003g).

and UK markets: ExxonMobil has signed a preliminary agreement to take 15 million tonnes of LNG annually for 25 years to the United Kingdom, although the volumes could also go to other European markets.

77 **Potential LNG supply capacity, Qatar**



The Qatargas III project, planned to be operational by 2008-09, is expected to have an annual capacity of 7.8 million tonnes of LNG. LNG sales are targeted at the United States east and gulf coast market, and the company currently has a preliminary agreement with ConocoPhillips for 7.5 million tonnes a year for 25 years from 2009.

RasGas has also proposed a large expansion project to export LNG to the United States. The project consists of two trains with a combined annual capacity of 15.6 million tonnes. The first train is due on line in 2008-09, with the second train to be operational between 2011-12. RasGas has a preliminary agreement with ExxonMobil to supply the full volume of LNG to the United States gulf coast.

All of the current Qatari project proposals are planning to supply Atlantic markets. It is likely that some of the capacity could also be sold into Asia Pacific markets as spot cargoes. However, in the study all capacity additions have been excluded from potential LNG supply capacity in the Asia Pacific market over the outlook period.

Other gas projects

In addition to expansions in LNG liquefaction capacity, Qatar is looking to diversify its gas portfolio through gas to liquids technology and regional gas pipeline projects. A reported seven GTL projects are in various stages of development in Qatar based on the North field (Platts 2003g; EIA 2003e). GTL projects provide an opportunity for Qatar to develop gas reserves without first securing markets.

Qatar will also been the main source of gas for the Dolphin project — an integrated natural gas pipeline grid linking Qatar, the United Arab Emirates and Oman. Qatar will initially supply the equivalent of 15 million tonnes of natural gas from 2006 through a subsea pipeline that will link the North Field to Abu Dhabi in the UAE. Links between Abu Dhabi, Dubai and Oman will be added at a later date (EIA 2003e). Although these countries have their own natural gas reserves, it is reported to be less costly to import Qatari gas via pipeline than to develop and treat their own non associated gas supplies.

Oman

Natural gas reserves

Proven recoverable reserves of natural gas in Oman are estimated to be around 0.9 trillion cubic metres (equivalent to 0.7 billion tonnes of LNG) at the end of 2003. Oman constitutes around 1.3 per cent of proven recoverable gas reserves in the Middle East and 0.5 per cent of world reserves. Based on proven recoverable reserves, the reserve to production ratio in Oman is 57.3 years (BP 2004). Most of Oman's natural gas reserves are located in central Oman and are associated with or located close to oil.

Gas production and exports

Natural gas production in Oman was 17.3 billion cubic metres (equivalent to 12.6 million tonnes of LNG) in 2002, compared with around 0.4 billion cubic metres in 1980. This represents annual growth in output of close to 19 per cent a year over that period, which is the most rapid among the LNG exporters to the Asia Pacific region. Much of the growth in natural gas production has occurred since 2000, when Oman began exporting LNG (IEA 2003a; figure 78). Around half of Oman's natural gas production in 2002 was consumed in the domestic market, including in the power sector, where gas accounts for more than 80 per cent of electricity output (IEA 2004c). LNG exports accounted for a further 46 per cent of gas production in Oman in 2002.

Oman currently has one LNG liquefaction plant, located at Qalhat, which commenced operations in the first half of 2000. The plant has a total annual liquefaction capacity of 6.6 million tonnes and comprises two liquefaction trains of equal capacity (table 80). The project has been developed by Oman LNG, of which the government of Oman owns 51 per cent.

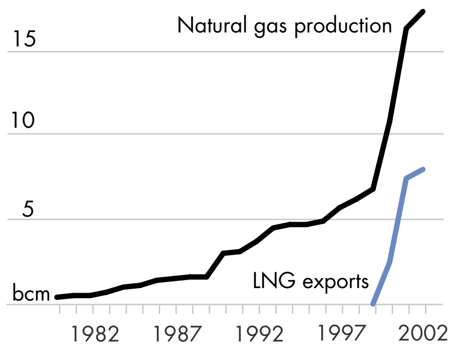
In 2003, Oman exported 6.7 million tonnes of LNG, representing around 5.5 per cent of world LNG trade and 7.6 per cent of exports to the Asia Pacific region (BP 2004). More than two thirds of Oman's LNG exports were to Korea, while smaller volumes were supplied to customers in Japan, Spain and the United States (table 81).

Oman LNG currently has long term supply contracts with KOGAS in Korea for 4.1 million tonnes of LNG a year, and Osaka Gas in Japan for 0.7 million tonnes a year (table 82). These contracts are due to expire in 2024 and 2025 respectively. The company also has a 20 year contract with Dahbol Power in India for 1.6 million tonnes a year, but the status of this contract is uncertain in light of the halt in construction of the Dahbol power plant and LNG terminal. Oman also sells LNG through short term and spot deliveries.

Outlook for LNG supply

Oman LNG is currently in the process of expanding its facility to include a third LNG train. The train is expected to add 3.3 million tonnes a year to production capacity by early 2006, which will raise Oman's total annual LNG supply capacity to close to 10 million tonnes (table 83; figure 79). Around half of the LNG from the third train

78 Natural gas production and LNG exports, Oman



80 Existing LNG projects, Oman

Project	Capacity	Trains	Start up
	Mtpa	no.	
Oman LNG	6.6	2	2000

Source: EIA (2003b).

81 LNG exports, by destination, Oman, 2003

	Mt	%
Korea	4.74	70.5
Japan	1.58	23.5
Spain	0.23	3.5
United States	0.18	2.6
Total	6.72	100.0

Source: BP (2004).

82 Existing long term LNG supply contracts, Oman

Project	To	Importer	Volume	Duration
			Mtpa	
Oman LNG	Korea	KOGAS	4.06	2000–24
Oman LNG	Japan	Osaka gas	0.66	2000–25
Oman LNG	India	Dabhol Power **a**	1.60	–

a The current status of the contract is uncertain in light of the ongoing halt in construction of the Dahbol power plant and LNG terminal.
Sources: Suzuki and Morikawa (2003); FACTS Inc. (2003a).

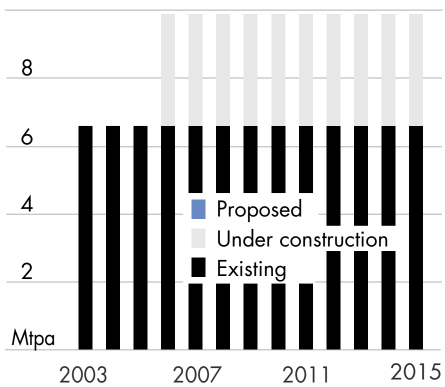
83 LNG projects under construction and proposed, Oman

Project	Capacity	Trains	New project	Start up
	Mtpa	no.	Y/N	
Under construction				
Oman LNG Train 3	3.3	1	N	2006

Source: EIA (2003b).

is expected to be supplied to Union Fenosa in Spain from early 2006 under a 20 year contract for 1.65 million tonnes a year. Oman LNG also recently signed long term contracts with Osaka gas in Japan for 0.8 million tonnes a year from 2009, and with Mitsubishi and Itochu in Japan for 0.8 and 0.7 million tonnes a year respectively from 2006. The latter two contracts are for trading purposes and it is not known where the LNG will be consumed. It is assumed that all LNG from Train 3, except for that contracted to Spain, will be available to supply Asia Pacific markets.

79 Potential LNG supply capacity, Oman



In view of the maturing of its oil fields, the Omani government has made diversification of the economy a key policy priority. Natural gas, particularly LNG, has become the key focus of these initiatives and the government has been investing heavily in the sector. Future expansion plans beyond the third LNG train have not been firmly articulated. However, the potential for significant further expansion is likely to be limited by the modest size of Oman's gas reserves (EIA 2003b,f).

United Arab Emirates

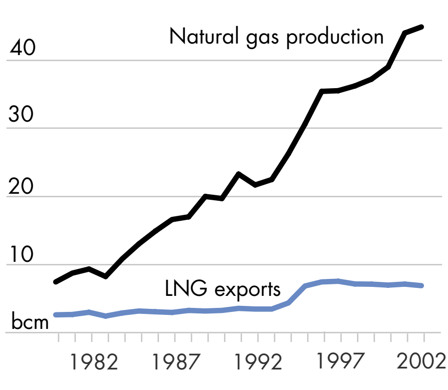
Natural gas reserves

Proven recoverable reserves of natural gas in the United Arab Emirates (UAE) were estimated to be 6.1 trillion cubic metres (equivalent to 4.4 billion tonnes of LNG) at the end of 2003. This represents around 8 per cent of proven recoverable gas reserves in the Middle East and 3.4 per cent of world reserves. Based on proven recoverable reserves of gas, the reserve to production ratio for the UAE is more than 100 years (BP 2004). The gas reserves used in LNG production in the UAE are located in Abu Dhabi, the largest of the seven emirates. Most of Abu Dhabi gas reserves are in the form of associated gas.

Gas production and exports

Natural gas production in the UAE has grown by close to 9 per cent a year over the past two decades. In 2002, the UAE produced 45 billion cubic metres of natural gas (equivalent to 33 million tonnes of LNG), compared with 7.4 billion cubic metres in 1980 (IEA 2003a; figure 80). Production has grown by close to 9 per cent a year over the past two decades. Much of the gas produced in the UAE is consumed domestically, with domestic gas consumption nearly doubling. This expansion reflects increased domestic use of electricity, a shifting toward gas fired power generation, and growing demand from the petrochemicals sector (EIA 2004e).

80 Natural gas production and LNG exports, United Arab Emirates



Around 15 per cent of gas production in the UAE is exported as

LNG. The UAE has one LNG export facility, located on Das Island in Abu Dhabi. The plant is operated by the Abu Dhabi Gas Liquefaction Company (ADGAS), and has an annual LNG supply capacity of 5.7 million tonnes. The plant began operating in 1977 with two trains, and was expanded to incorporate a third train in 1994 (table 84).

84 Existing LNG export projects, United Arab Emirates

Project	Capacity	Trains	Start up
	Mtpa	no.	
Das Island	5.7	3	1977
Das Island I	3.2	2	1977
Das Island II	2.5	1	1994

Source: EIA (2003b).

85 LNG exports, by destination, United Arab Emirates, 2003

	Mt	%
Japan	5.02	96.6
Spain	0.18	3.4
Total	5.19	100.0

Source: BP (2004).

LNG exports from the UAE have been relatively flat in recent years, with only a short period of growth in the mid-1990s. The growth coincided with the addition of the third train. In 2003, LNG exports were 5.2 million tonnes, which represented 4.2 per cent of world LNG trade and 6.1 per cent of exports to the Asia Pacific region. The majority of UAE exports in 2003 were to Japan (around 97 per cent), while small volumes were also supplied to Spain (table 85).

The UAE currently has a long term contract with TEPCO in Japan to supply 4.7 million tonnes of LNG a year, due to expire in 2019 (table 86). ADGAS also has a long term contract for 0.5 million tonnes a year with Dahbol Power in India; however, as in the case of Oman, the likely timing and status of this contract are uncertain. In addition, ADGAS currently has a four year contract to supply up to 0.75 million tonnes a year to Spain, and has also been selling surplus cargoes through short term and spot trades.

Outlook for LNG supply

There are no known LNG projects under construction or proposed in the UAE, and its LNG supply capacity is expected to remain constant over the period to 2015 (figure 81). Despite its relatively large natural gas reserves, the UAE is unlikely to expand its production of LNG as it uses much of its gas for domestic purposes (Wybrew-Bond and Stern 2002; EIA 2003b). The government has also been focusing policy toward projects that diversify the

86 Existing long term LNG supply contracts, United Arab Emirates

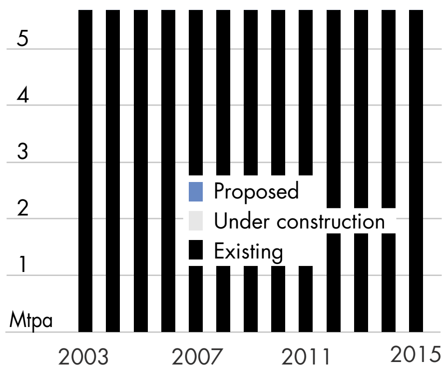
Project	To	Importer	Volume	Duration
			Mtpa	
Das Island	Japan	TEPCO	4.7	1994–2019
Das Island	India	Dahbol Power **a**	0.5	–

a The current status of the contract is uncertain in light of the ongoing halt in construction of the Dahbol power plant and LNG terminal.
Sources: Petroleum Economist (2003); Suzuki and Morikawa (2003).

economy away from oil and gas (EIA 2004e).

In light of its expected ongoing growth in domestic gas consumption, the UAE is planning to begin importing natural gas from Qatar via pipeline. The Dolphin project aims to interconnect the natural gas grids of Qatar, UAE and Oman, with supplies expected to start in late 2006 (EIA 2004e).

81 Potential LNG supply capacity, United Arab Emirates



Russian Federation

Natural gas reserves

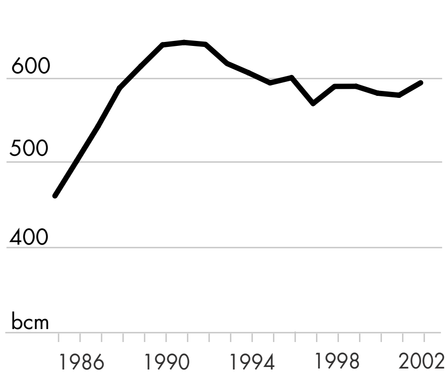
The Russian Federation has the largest proven recoverable reserves of natural gas in the world, estimated at around 47 trillion cubic metres (equivalent to 34 billion tonnes of LNG) at the end of 2003. This is equivalent to 27 per cent of world proven recoverable reserves, nearly twice as large as the next country, Iran. The Russian Federation's reserve to production ratio is around 81.2 years (BP 2004).

The Russian Federation has significant gas reserves across much of the country. Those likely to supply gas to Asia Pacific markets are located in eastern Siberia and the far east, including Sakhalin Island.

Gas production and exports

In line with its large gas reserves, the Russian Federation is the world's largest natural gas producer, as well as the world's largest gas exporter. However, there has been little growth in the gas sector in recent years, with production and consumption remaining relatively flat since the early 1990s. Natural gas production in 2002 was 595 billion cubic metres (equivalent to 434 million tonnes of LNG) (IEA 2003a; figure 82). The country currently exports natural gas via pipeline to around 30 countries, including Ukraine, Germany, Italy and Belarus. It does not currently export LNG.

82 **Natural gas production, Russian Federation**

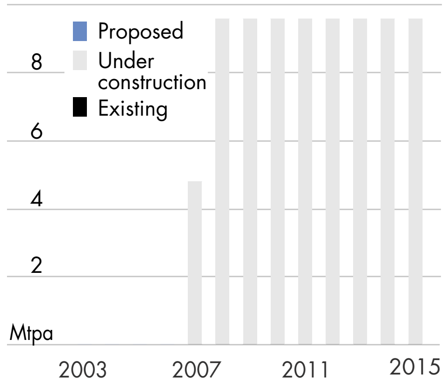


To date, growth in the Russian Federation's natural gas sector has been constrained by ageing fields, excess regulation, Gazprom's monopolistic control of the industry, and insufficient export pipelines. Gazprom currently produces nearly 90 per cent of natural gas output in the Russian Federation (EIA 2004f).

Outlook for LNG supply

The first LNG plant is under construction on the southern tip of Sakhalin Island near Prigorodnoye, off the Russian Federation's far east coast. The LNG plant is part of the Sakhalin II Phase 2 project, which is an integrated oil and gas development. The two train LNG facility will have an annual liquefaction capacity of 9.6 million tonnes. LNG exports from the first train are scheduled to begin in 2007, with train 2 due to follow in 2008 (figure 83; table 87). A third train has been suggested, although no firm proposal exists at this time.

83 **Potential LNG supply capacity, Russian Federation**



Sakhalin Energy has secured agreements with four Japanese utilities for up to 3.4 million tonnes of LNG a year for periods in excess of twenty years (table 88). These include Tokyo Gas (1.1 million tonnes for 24 years), Tokyo Electric Power Company (1.5 million tonnes for 22 years), Kyushu Electric Power Company (0.5 million tonnes for 21 years), and more recently Toho Gas (up to 0.3 million tonnes for 23 years). Sakhalin Energy has also signed an agreement to supply 1.6 million tonnes a year for 20 years to Shell from 2008, destined for a planned terminal in Baja California, Mexico. There is still, however, a significant volume of uncommitted production capacity.

Gazprom has also announced plans to build an LNG plant based on the Shtokman field in the Arctic Barents Sea to target gas markets in Canada and the northeast United States. A possible onshore location for the plant is near the deepwater ice free port of Murmansk on the Kola Peninsula (Platts

87 LNG projects under construction and proposed, Russian Federation

Project	Capacity	Trains	New project	Start up
	Mtpa	no.	Y/N	
Under construction				
Sakhalin 2	9.6	2	Y	2007
Train 1	4.8	1	–	2007
Train 2	4.8	1	–	2008

Sources: Sakhalin Energy (2003); EIA (2003b).

88 Existing long term LNG supply contracts, Russian Federation

Project	To	Importer	Volume	Duration
			Mtpa	
Sakhalin 2	Japan	Tokyo Electric Power Company	1.5	2007–29
Sakhalin 2	Japan	Tokyo Gas	1.1	2007–31
Sakhalin 2	Japan	Kyushu Electric Power Company	0.5	2009–31
Sakhalin 2	Japan	Toho Gas	0.3	2010–33
Sakhalin 2	Mexico	Shell Eastern Trading	1.6	2008–28

Sources: Sakhalin Energy (2004; 2003); Shell (2004e).

2003h, 2004j). However, this project is of uncertain timing and, given its location, is unlikely to service Asia Pacific markets.

The successful development of the Russian Federation's first LNG project could prompt further projects elsewhere in the country, including to supply Asia Pacific markets. However, the country's geography also poses an issue for LNG export growth, with much of the Russian coast line subject to permanent or seasonal ice that prevents LNG carriers from operating (Energy Economist 2004a).

There is also potential for pipeline gas supplies from the Russian Federation to north east China and Korea from the large Irkutsk field in eastern Siberia, and from Sakhalin Island to Japan or possibly Korea. These projects are discussed in more detail in chapter 6. While there are significant obstacles to the development of these projects this decade, they could possibly materialise in the longer term. Russian pipeline export projects could compete with LNG in Asia Pacific markets, particularly in Japan and Korea. It is possible that the development of Russian LNG supplies to the Asia Pacific has delayed the realisation of markets for its pipeline gas, at least in Japan. Conversely, the possible materialisation of Russian pipeline gas in the medium to longer term would be likely to displace some LNG exports to Asia Pacific markets.

5

LNG in the United States: developing a west coast market

Following several decades of variable LNG import levels, imports of LNG into the United States more than doubled during 2003 to record levels. There has also been renewed interest in LNG imports over the medium to longer term. Recent sustained high domestic gas prices combined with declining costs throughout the LNG supply chain have enhanced the competitiveness of LNG in the United States gas market. In addition, future gas supplies from domestic and Canadian sources are forecast to be below gas demand levels. Recent regulatory changes have also increased interest in investment in LNG import terminals, including on the west coast.

LNG trade in the United States has traditionally consisted of imports along the east coast from Atlantic market suppliers, including Algeria and Trinidad and Tobago. While supplying occasional spot cargoes when prices are high, LNG suppliers to the Asia Pacific market have played a limited role in the United States. However, there are significant plans to develop LNG import terminals on the north American west coast, including California and Mexico, to fuel the burgeoning demand for gas in the region. If successful, this could result in Asia Pacific LNG in the United States market by the end of the decade. LNG is expected to be competitive with alternative gas supplies to California, with imports constrained principally by LNG terminal capacity.

The US natural gas market

Economic overview

The United States is the world's largest economy and represents one-fifth of world economic output. Despite occasional downturns, the United States has enjoyed relatively strong economic growth over the past two decades, with real GDP expanding at an average annual rate of 3.1 per cent since 1980 (table 90). Although in recession during 2001 and early 2002, economic output recovered in 2003 to rise by 3.1 per cent. This robust growth has been supported by an increase in labor productivity associated with the diffusion of information technology throughout many sectors of the economy (EIA 2004g). GDP growth in 2004 is forecast to be 4.3 per cent (Penm 2004).

Energy consumption

Between 1980 and 2002, total primary energy consumption in the United States grew at an average annual rate of 1.4 per cent, to reach 2458 million tonnes of oil equivalent. This compares with 1971 million tonnes of oil equivalent in 1980. Energy consumption expanded more slowly than economic output over this period, as the economy shifted to less energy intensive industries and adopted more efficient energy using technologies (table 89).

Fossil fuels — coal, oil and natural gas — account for more than 85 per cent of primary energy consumption in the United States. Oil accounts for the largest share of energy consumption, at 39 per cent in 2002, although its share has fallen since the oil price shocks of the 1970s. Natural gas accounts for the second largest share of energy consumption in the United States at close to 24 per cent in 2002, with coal accounting for a further 23 per cent. The shares of natural gas and coal have remained relatively steady over the past decade (table 90).

Natural gas consumption

Although the share of natural gas in primary energy consumption has remained relatively unchanged, gas consumption in the United States has increased by nearly one third since 1986, when gas consumption was at its lowest level in recent decades. Natural gas consumption in 2002 was 636 billion cubic metres (equivalent to 464 million tonnes of LNG), compared

89 Key economic indicators, United States

		1980	1990	2000	2002	Annual growth 1980–90	Annual growth 1990–2000	Annual growth 2000–02
						%	%	%
Real GDP (1995 prices)	US$b	4 771.9	6 520.5	8 955.1	9 196.4	3.2	3.2	1.3
Population	million	227.7	250.0	282.1	287.5	0.9	1.2	0.9
Energy consumption	Mtoe	1 971.1	2 134.4	2 495.3	2 457.9	0.8	1.6	–0.8
Energy intensity	toe/US$’000	0.41	0.33	0.28	0.27	–2.3	–1.6	–2.1
Energy consumption per person	toe	8.66	8.54	8.84	8.55	–0.1	0.4	–1.7

Sources: IEA (2004a), EIA (2003g).

90 Total primary energy consumption, United States

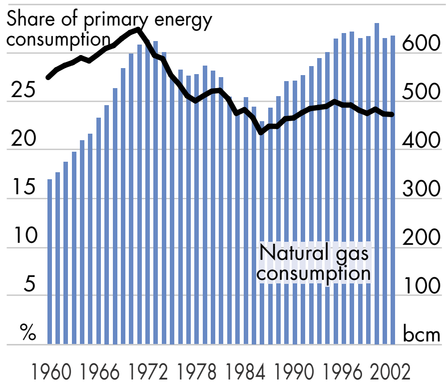
	1980		1990		2000		2002	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Coal	388	19.7	483	22.6	571	22.9	561	22.8
Oil	862	43.7	846	39.6	968	38.8	962	39.1
Natural gas	514	26.1	497	23.3	604	24.2	581	23.6
Nuclear	69	3.5	154	7.2	198	7.9	205	8.4
Renewables	65	3.3	78	3.6	84	3.4	81	3.3
Total	1 971	100.0	2 134	100.0	2 495	100.0	2 458	100.0

Source: EIA (2003g).

with 459 billion cubic metres in 1986 (EIA 2004a; figure 84). Consumption of natural gas in the United States now accounts for more than one quarter of the world's gas consumption.

Despite the recent growth, gas consumption in 2002 was less than 2 per cent higher than in 1972. The rapid growth in gas use during the 1960s was facilitated by the regulatory environment at the time that set artificially low gas prices. However, this policy led to a decline in exploration activity and domestic gas shortages began to emerge. In response, gas prices were tied to oil prices, which occurred just prior to the first of the oil price shocks in the 1970s. Rapidly rising oil prices led to high gas prices and gas consumption declined from 1972 for more than a decade. Following deregulation of wellhead prices in the mid-1980s, gas prices fell sharply as gas on gas competition in the United States commenced. Gas consumption began to rise again until 2000, when the increasing gas prices resulted in consumption stalling.

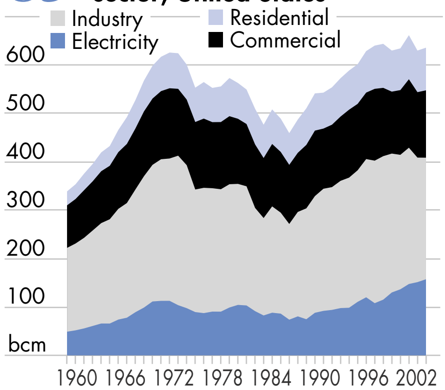
84 Natural gas consumption, United States



Gas use, by sector

Much of the recent growth in gas consumption has been driven by use in the electricity sector, which has averaged 4.7 per cent annual growth over the period since 1986 (EIA 2004a; figure 85). This was facilitated by the widespread uptake of the combined cycle gas turbine, which has properties that make it well suited for supporting the competitive electricity markets that evolved throughout the 1990s. These turbines can be built quickly, at a relatively small minimum efficient scale, are less capital intensive and can be more easily sited than conventional coal fired plants.

85 **Natural gas consumption, by sector, United States**



Almost all of the new electricity generation capacity built in the past decade in the United States has been gas fired, and natural gas accounted for 18 per cent of electricity output in 2002. However, coal fired power generation remains the dominant source of electricity in the United States, accounting for half of electricity output in 2002 (table 91). Nuclear power is the second largest source of electricity after coal, accounting for 20 per cent of electricity output in that year.

Industrial demand for gas has accounted for approximately 40 per cent of gas consumption since the 1960s. Reflecting the recent high gas prices and downturn in industrial production in the United States since 2000, gas consumption in the industry sector fell by 15 per cent between 2000 and 2002. In particular, some industrial and petrochemical users have shifted away from gas in response to high prices, commonly known as ‘demand

91 **Electricity generation, by fuel, United States**

	1980		1990		2000		2002	
	TWh	%	TWh	%	TWh	%	TWh	%
Coal	1 162	50.7	1 594	52.5	1 966	51.7	1 933	50.1
Oil	246	10.7	137	4.5	125	3.3	106	2.7
Natural gas	346	15.1	373	12.3	601	15.8	691	17.9
Nuclear	251	11.0	577	19.0	754	19.8	780	20.2
Renewables	285	12.4	357	11.8	356	9.4	348	9.0
Total	2 290	100.0	3 038	100.0	3 802	100.0	3 858	100.0

Source: EIA (2003g).

destruction'. The residential and commercial sectors accounted for a further 22 and 14 per cent of natural gas consumption in 2002.

Outlook for natural gas demand

Key assumptions for the United States

The US economy is assumed to grow at an average annual rate of 3.3 per cent in the period 2001–15, on the expectation that recent trends in productivity growth and technological progress will continue. Gas is expected to continue to be the fuel of choice for new electricity generating capacity in the United States, with its share expanding to 23 per cent of electricity output by 2015 (table 92). This is principally at the expense of coal and nuclear power and by 2007 natural gas is expected to overtake nuclear power as the second largest source of electricity after coal (EIA 2004g).

92 Assumed fuel mix in electricity generation, United States

	2002	2010	2015
	%	%	%
Coal	50.1	50.0	48.4
Oil	2.7	1.7	2.5
Natural gas	17.9	20.7	22.8
Nuclear	20.2	17.6	16.6
Renewables	9.0	10.0	9.7
Total	100.0	100.0	100.0

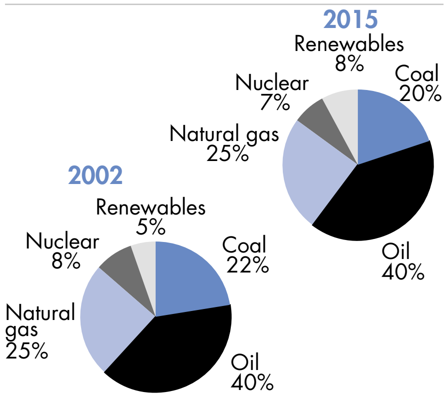
Natural gas demand projections

Energy consumption in the United States is projected to grow at an average rate of 1.4 per cent a year to reach 2979 million tonnes of oil equivalent in 2015, compared with 2458 million tonnes of oil equivalent in 2002. The rate of growth in energy consumption is lower than that of GDP, as a result of ongoing structural shifts away from energy intensive industries and the uptake of more energy efficient technologies.

The rate of growth in natural gas consumption is projected to surpass all other fuels except renewables. Gas consumption is projected to increase at an average annual rate of 1.5 per cent a year, from 635 billion cubic metres in 2001 to 822 billion cubic metres (equivalent to 600 million tonnes of LNG) in 2015. Gas is projected to account for 25 per cent of primary energy consumption by 2015, slightly higher than in 2002 (figure 86). The growth in natural gas demand in the United States will require significant expansion in gas pipeline capacity and storage facilities, as there is little spare capacity in the existing system.

Ongoing strong growth in gas fired power generation is expected to be the principal driver of the growth in gas consumption in the United States over the outlook period (figure 87). Consumption of gas in the electricity sector is projected to rise by an average 3.1 per cent a year out to 2015. Continued high gas prices relative to other fuels over the outlook period is expected to affect gas consumption in other sectors, with some substitution away from gas occurring.

86 Primary energy consumption, by fuel, United States



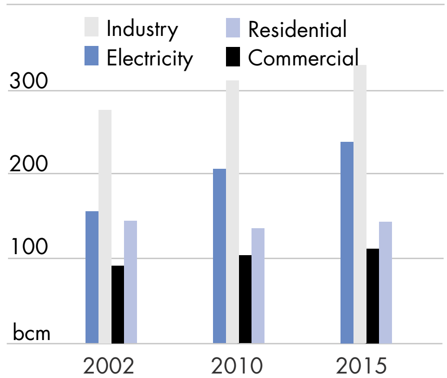
Domestic natural gas supply

Proved recoverable reserves of natural gas in the United States were around 5.2 trillion cubic metres (equal to 3.8 billion tonnes of LNG) at the end of 2003 (BP 2004). The reserves to production ratio in the United States is 9.5 years and has remained around this level for the past two decades. However, when technically recoverable resources of natural gas (discovered, unproved and undiscovered) are considered, reserve estimates are much higher, totaling 45.8 trillion cubic metres. This is equal to around 85 times the gas production level in 2002 (EIA 2003h).

Domestic gas production in the United States comes from a range of sources, including offshore wells and conventional and unconventional onshore resources. Unconventional resources include coal seam methane and low permeability sandstone and shale formations.

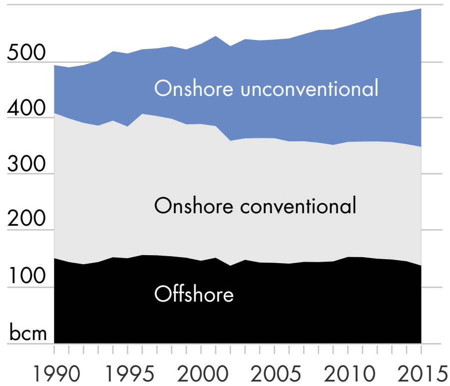
Total gas production has increased at around 0.7 per cent a year since 1990, only half that of the rate of increase in consumption. This reflects the relative maturity of

87 Projected natural gas consumption, by sector, United States



conventional gas resources in the United States. While high gas prices since 2000 have led to a significant rise in drilling, this has only been sufficient to maintain production (EIA 2004h). The US Energy Information Administration (EIA) projects that gas production from conventional onshore reserves will decline out to 2015. Production from offshore wells will increase slightly out to 2010 in response to higher prices encouraging drilling in deeper waters, but is expected to decline after 2010 (EIA 2004g; figure 88).

88 **Natural gas production, by resource type, United States**



Much of the recent rise in production has been sourced from unconventional gas resources. In 1990, production from these higher costs sources accounted for approximately 17 per cent of total gas production, rising to 32 per cent by 2002. This trend is likely to continue, with unconventional resources projected to become the largest source of domestic gas supply in the United States, accounting for 43 per cent of production in 2015. This compares with a projected 33 per cent for conventional onshore gas and 24 per cent for offshore gas (EIA 2004g).

Gas imports

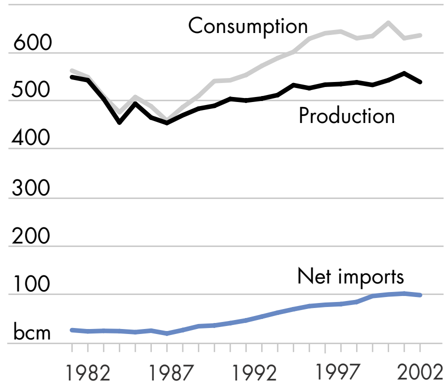
The United States has been a net importer of small quantities of natural gas for several decades. However, with production increasing at only half the rate of consumption since 1986, increasing import volumes have been required to balance gas demand and supply. Net imports have grown at an average annual rate of 9 per cent since 1986, and now account for more than 15 per cent of gas consumption in the United States (EIA 2004a; figure 89).

The majority of gas imports into the United States are from Canada via an extensive gas pipeline network. In 2002, net imports from Canada accounted for 96 per cent of total net imports. However, net Canadian pipeline imports fell significantly in 2003 to account for 88 per cent. This reflects a slowing of gas production in Canada and the increasing competitiveness of LNG imports in the United States market in that year.

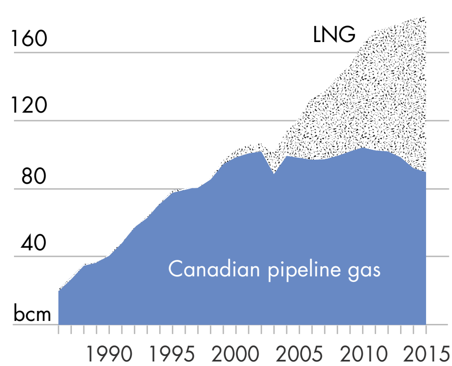
The capacity of Canada to meet the continued growth in US gas demand over the coming years appears limited. Production of natural gas in Canada is beginning to slow as gas reserves mature and there is growing demand for natural gas within Canada (EIA 2004g). Further, the size of Canada's natural gas resource base is uncertain. The Canadian National Energy Board has significantly downgraded conventional gas resource levels, resulting in reductions of future gas production projections. To maintain or potentially increase Canadian production, it would be necessary to develop unconventional and frontier gas sources, which are subject to uncertainty about future production potential (CNEB 2003).

US gas imports from Canada are projected by the EIA to remain relatively stable out to 2010, after which they are projected to decline sharply. To make up for the shortfall in domestic production and Canadian imports, increased volumes of LNG imports are expected to be required in the United States over the outlook period (EIA 2004g; figure 90).

89 Natural gas production, consumption and imports, United States



90 Net imports of natural gas, United States

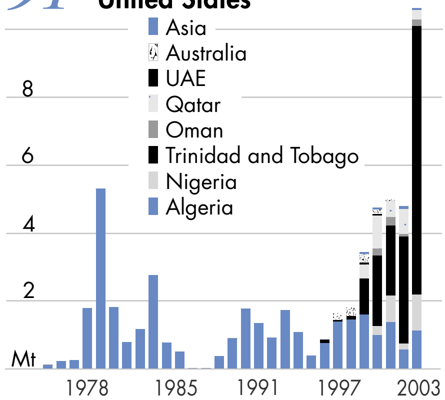


The role of LNG imports

The United States is both an importer and an exporter of LNG. As discussed in chapter 4, LNG has been exported to Japan from Kenai in Alaska since 1969. The plant has an annual liquefaction capacity of 1.4 million tonnes, and 1.2 million tonnes of LNG was exported in 2003.

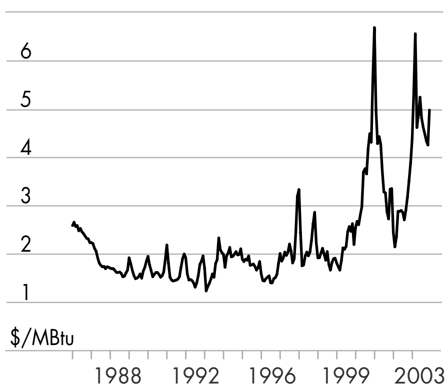
LNG imports to the United States began in 1971, but volumes have been variable for several decades, accounting for less than 1 per cent of net imports until 2001. Since the mid-1990s, imports of LNG have been rising. In 2002, 4.8 million tonnes of LNG was imported, equivalent to 4 per cent of net imports. Imports of LNG more than doubled during 2003 to reach 10.6 million tonnes (EIA 2004a; figure 91). This represented 12 per cent of net imports and 2.2 per cent of total gas consumption in the United States. The US share of world LNG trade rose from 4 per cent in 2002 to more than 8 per cent in 2003. The recent surge in LNG imports reflects high domestic gas prices, as well as increased availability of LNG cargoes from nearby suppliers.

91 LNG imports, by source, United States



Imports of LNG into the United States are generally considered to be competitive with domestic supplies and imported gas from Canada when domestic wellhead prices rise above US$3.50 per million British thermal units. Gas prices rose above this level for a twelve month period in 2000-01 and gas prices surpassed that level again in late 2002. Since late 2002, gas prices in the United States have remained consistently high (EIA 2004a; figure 92; box 8).

92 Average monthly natural gas prices, United States



While Algeria has traditionally been the largest supplier of LNG to the United States, LNG from Trinidad and Tobago, Nigeria and the Middle East has underpinned the growth in imports since 1999. Supplies from Trinidad and Tobago accounted for three quarters of LNG imports into the United States in 2003 (table 93). The recent growth in LNG imports from Trinidad and Tobago reflects the start up of the Atlantic LNG plant in 1999, and in particular the completion of the third LNG train in April 2003. 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 US market even when gas prices are low (Flower and King 2002).

93 LNG imports, by source, United States, 2003

	Mt	%
Trinidad and Tobago	7.9	74.6
Algeria	1.1	10.5
Nigeria	1.1	9.9
Qatar	0.3	2.7
Oman	0.2	1.7
Malaysia	0.1	0.5
Total	10.6	100.0

Source: BP (2004).

Although the majority of international LNG trade is conducted via long term contracts, much of the growth in imports into the United States has occurred through short term contracts (up to two years) and spot market purchases, which accounted for three quarters of LNG imports in 2002 (EIA 2003i).

LNG import infrastructure

There are four LNG import terminals in the United States, located on the east and Gulf of Mexico coasts: Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana. These termi-

Box 8: **Natural gas pricing in the United States**

The gas market in the United States is considered to be the most mature gas market in the world and gas is traded extensively across the United States, and with Canada and Mexico. There are more than 500 000 kilometres of pipeline network in the United States, with nearly 8000 gas producers connected to more than 1600 distributors through more than 60 major interstate pipeline systems and hundreds of smaller pipeline companies. There are more than 120 locations within the national pipeline network where gas buyers and sellers can exchange gas, and natural gas is freely traded between buyers and sellers.

Gas prices in the United States are set by the balance of supply and demand. The extensively linked network of gas supply and consumption regions creates a single gas market across the United States that permits an efficient price discovery process for determining the market price of gas. Observations of prices for gas at 63 trading points between 1986 and 1997 indicate that 82 per cent of price

continued

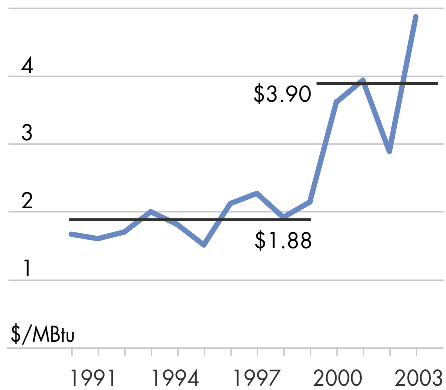
Box 8: **Natural gas pricing in the United States** *continued*

pairs between trading points have gas prices that are identical after adjusting for transport charges. This suggests that, even though the physical pipeline network does not have connections between all trading points, the United States market is sufficiently mature that prices can be arbitraged across the country (MacAvoy 2000). However, although the regions are connected, prices can and do vary to reflect regional characteristics, particularly at times of peak demand. The price at the Henry Hub, a key pipeline interconnection in Louisiana, is used as the reference point for natural gas prices across the United States.

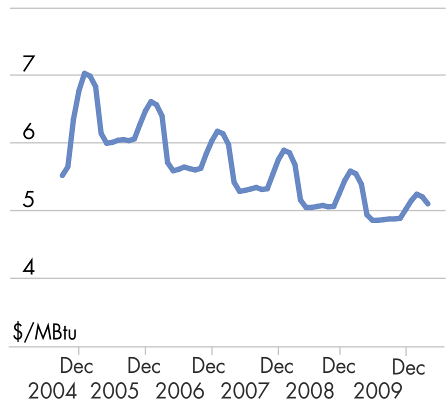
Gas prices over the past three years have become higher and more volatile. Between 1990 and 1999, prices averaged US$1.88/MBtu. Since 2000, prices have averaged US$3.90/MBtu (EIA 2004a; figure 93). The trend increase in prices reflects a growing recognition that traditional supplies in the United States are stagnating, that the resource base in Canada has matured and import availability from Canada has peaked. The recent volatility in 2001 and 2003 reflects extended and colder winters with a running down of gas storage.

Reflecting the depth of the gas market in the United States, there is an active futures market on the New York Mercantile Exchange that uses the Henry Hub as the delivery point for contracts. Prices for the natural gas futures contracts reflect an expectation that gas prices in the United States will remain high for the rest of the decade, declining gradually from current levels to average around US$5/MBtu from 2007 (figure 94).

93 Average annual natural gas wellhead prices, United States



94 NYMEX natural gas futures contract prices August 2004



nals currently have a combined annual base capacity of 19.6 million tonnes and a peak capacity of 28.4 million tonnes (table 94).

The Lake Charles terminal was the last import terminal to be built in the United States in 1980. However, as domestic gas prices rose during the 1980s and LNG became uncompetitive for baseload gas needs, three of the four terminals were mothballed. Only the LNG terminal in Everett, Massachusetts has operated continuously. All four import terminals were fully operational for the first time in 2003.

Capacity at LNG terminals in the United States is currently underutilised (EIA 2004h). LNG imports were close to terminal capacity in only a few months of 2003, despite continued high gas prices. LNG imports into the

94 LNG receiving terminals, United States

	Start up	Annual capacity Base	Annual capacity Peak	Imports 2003
		Mt	Mt	Mt
Everett, Massachusetts				
Existing	1971	5.6	7.9	3.3
Lake Charles, Louisiana				
Existing	1980	4.8	7.7	5.0
Planned expansion (2005)		4.4	2.3	
Planned expansion (2007)		4.6	6.1	
Planned total		13.8	16.1	
Cove Point, Maryland				
Existing	1978	5.7	7.7	1.4
Planned expansion (2008)		6.1	6.1	
Planned total		11.9	13.8	
Elba Island, Georgia				
Existing	1978	3.4	5.2	0.9
Planned expansion (2005)		2.8	4.1	
Planned total		6.2	9.3	
Total				
Existing		19.6	28.4	10.6
Planned expansion		17.9	18.7	
Planned total		37.4	47.1	

Sources: EIA (2003i, 2004h).

United States were limited by the availability of spare world LNG supply capacity and tankers (Neil 2004a).

New import terminal capacity

All four existing import terminals have recently completed expansions or plan to expand their regasification capacity in the next few years. This will increase peak annual import capacity in the United States to 34.4 million tonnes by 2006.

There are also more than twenty proposals to build new LNG import terminals in north America by the end of the decade, including in Canada and Mexico (EIA 2004h; figure 95). Many proposals have been stimulated by recent changes to regulatory arrangements for LNG terminals in the United States (box 9). The first new LNG terminal in more than 20 years is scheduled to open on the Gulf of Mexico in 2007 following its final approval in 2003. Two offshore terminals have also received approval, and it is expected that several additional LNG terminals could be constructed in the coming decade. However, it is anticipated that almost 60 per cent of the increase in LNG imports will be served by expanded capacity at the four existing terminals (EIA 2003i; 2004h).

95 **LNG receiving terminals, north America**
June 2004

There are currently six proposals to construct LNG import terminals to serve west coast natural gas markets, to be located in California or Baja California in Mexico. Interest in important terminals is also emerging further north, including Oregon and British Columbia in Canada. The potential for LNG imports on the west coast over the next decade is discussed in more detail in the following section.

Box 9: **Regulatory changes affecting LNG import terminals in the United States**

A key factor stimulating interest in establishing new LNG import terminals in the United States is recent changes to the regulatory framework. Until late 2002, LNG import terminals in the United States were considered to be part of the gas transport chain, similar to gas pipelines. Prices were regulated at cost of service rates: that is, the setting of prices for access to the terminals allowed only the recovery of costs (Vallee 2003). Terminal operators were also required to provide open access to terminal capacity: under the open access arrangements, unused capacity is auctioned off on a monthly, six-monthly or annual basis.

These regulations did not recognise that LNG, once it has been regasified, competes with other sources of natural gas, making LNG terminal operators equivalent to other onshore gas producers. This issue, as well as concerns that LNG importers faced substantially increased commercial risks because access to terminals could not be guaranteed and hence LNG projects might not proceed, led to a revision of the regulatory arrangements for LNG import terminals.

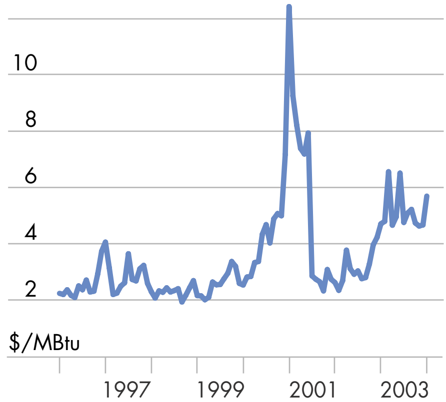
In December 2002, the United States Federal Energy Regulatory Commission (FERC), the permitting body for onshore LNG import terminals, removed the open access requirement for new onshore terminals and permitted the charging of market based rates for services. This decision, known as the Hackberry decision, recognises LNG as a gas supply source and places new onshore terminals on an equal footing with offshore terminals that are regulated separately by the U.S. Coast Guard and Maritime Administration.

Existing onshore terminals will continue to operate under open access and regulated rates but FERC has indicated a willingness to allow them to modify their regulatory status as long as their existing customers are in agreement.

In addition, the Maritime Security Act of 2002 was amended in November 2002 to include offshore natural gas facilities. The legislation transferred jurisdiction for offshore natural gas facilities from the FERC to the Maritime Administration and the U.S. Coast Guard. This has lowered the regulatory hurdles faced by potential developers of offshore LNG receiving terminals, and streamlined the permitting process.

A west coast LNG market

96 **City gate gas prices, California**
Monthly, ended January 2004



Recent interest in importing LNG has extended to the west coast of north America, where several LNG import terminals have been proposed to be operational by the end of the decade. The largest potential market for imported LNG along the west coast will be the state of California. The impetus for LNG imports into California is similar to the United States as a whole — ongoing high gas prices and a requirement for additional gas supplies — as well as a recent state policy focus on ensuring a reliable supply of reasonably priced natural gas. LNG is being positioned in California as a competitive alternative gas supply source that also has some potential to stabilise gas prices and mitigate gas price spikes through the storage potential of LNG import terminals (CEC 2003a,b). Gas prices in California have been increasingly volatile since 2000 (EIA 2004a; figure 96).

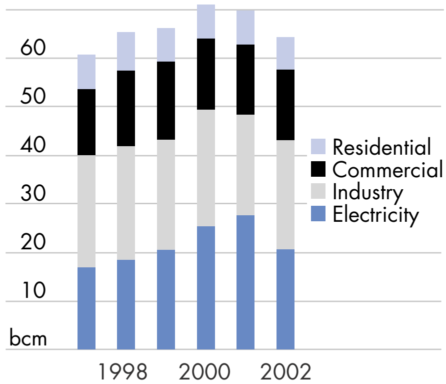
Californian gas consumption

The level of economic output in the state of California makes it equivalent to the world's fifth largest economy and its population is expected to exceed 40 million by 2010. California is the second largest consumer of natural gas in the United States, accounting for 10 per cent in 2002, or 64.4 billion cubic metres (equivalent to 47 million tonnes of LNG). Gas fired electricity generation plants in California account for approximately one third of total gas consumption, as does the industry sector and the combined residential and commercial sectors (EIA 2004a; figure 97).

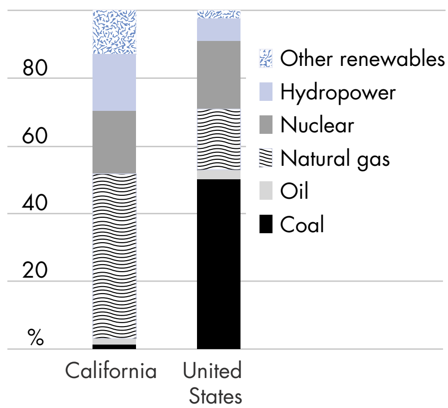
Over the past decade, growth in natural gas consumption in California has been underpinned by gas fired power generation, which has increased by 4.5 per cent a year since 1990. As in other parts of the United States, gas fired generation has become the technology of choice for new capacity in California as it is more efficient, more flexible to site and operate, and cheaper and cleaner than many other options. Indeed, gas accounted for close to half of electricity output in California in 2002, compared with 18 per cent on average across the United States (EIA 2004b; figure 98). More than 90 per cent of the generation capacity added in California over the past twenty years has been gas fired. California is likely to remain dependent on natural gas for power generation, with constrained water supplies in the state placing pressure on other options, including hydropower (CEC 2003b).

The California Energy Commission has projected that Californian gas demand will grow at an average rate of 1.0 per cent a year over the coming decade to reach 69 billion cubic metres in 2013 (equivalent to 50 million tonnes of LNG). This is underpinned by growth in gas use in power generation, which is projected to increase at 1.5 per cent a year over that period. In contrast, demand in the large industrial sector is projected to grow at 0.4 per cent annually, while that in the residential, commercial and small industrial sectors is projected to expand at an average annual rate of 0.9 per cent (CEC 2003c).

97 **Natural gas consumption, by sector, California**



98 **Electricity generation, by fuel, 2002**



Californian gas supply

Nearly 85 per cent of gas consumed in California arrives through interstate pipelines. In 2002, California was supplied by gas from four main regions: Californian gas fields (18 per cent); basins in the south west of the United States — the San Juan (New Mexico) and Permian (Texas) basins (43 per cent); Canada (26 per cent); and basins in the Rocky Mountains (13 per cent) (table 95). California competes with other states for natural gas supply and is located at the end of interstate natural gas pipelines, making its consumers vulnerable to gas supply disruptions and price volatility (CEC 2003c).

95 Natural gas supplies to California, 2003

	Bcm	%
California	12.0	17.5
Rocky Mountains	9.3	13.5
San Juan and Permian	29.3	42.8
Canada	18.0	26.2
Total	68.6	100

As discussed earlier, average gas prices are nearly identical across most regions of the United States after accounting for transport costs. Although there is limited transport infrastructure between the east and west coast markets, with only a small number of pipelines linking the regions, the price of gas in California generally reflects the supply and demand conditions throughout north America. The limited transport infrastructure between the east and west coast markets reflects that supplies from other regions, including Canada, into both the west and east coast regions provide lower cost gas supply options than additional east to west gas supply options.

While existing pipeline capacity to California is expected to meet its gas supply requirements until around 2006, California will require infrastructure enhancements to meet future demand. This could include additional pipeline capacity, increased in-state gas production capacity, or nontraditional supply sources such as LNG. Over the next decade, production from California gas supplies and the south west basins is expected to decline, while potential growth in imports from Canada is also limited. Natural gas from these regions is also expected to cost more than in the past (CEC 2003a,b,c).

There is some potential to develop gas supply further from the recently developed Rocky Mountain basins. However, much of the gas is located beneath ecologically protected public lands, raising some environmental and local community concerns about further developing these resources. In addition, the cost of building new pipelines is now relatively high across the United States (CEC 2003c).

Potential for LNG

Alternatively, investment in LNG import terminals is being considered to increase gas supplies into the California gas market. The development of non traditional supply sources such as LNG will depend on its competitiveness with other options. That is, for regasified LNG delivered to California to be economic, it will need to compete against existing gas supply sources and the development of further pipeline infrastructure.

Projected forward prices for the winter of 2005-06 to supply the Southern Californian gas utility — which retails half of California's gas supply — suggest that regasified LNG needs to be delivered at less than $4.59/MBtu if it is to compete with alternative gas supplies. While estimates vary depending on the source of the LNG, it has been projected that LNG can be delivered and regasified for less than $3.80/MBtu (Lund 2003). This, along with other gas price forecasts, suggests that there is scope for LNG to become an important alternative source of gas supply in California, potentially displacing some higher cost sources.

West coast LNG terminals

More than a dozen LNG import terminals have been proposed in recent years to serve the west coast of north America. To date, at least eight proposals for onshore terminals have been abandoned or combined into other propos-

96 Proposed LNG terminals on the north American west coast

Project	Type	Location	Owners	Capacity Mtpa	Status	Start up
California						
Cabrillo Port LNG	Offshore	Oxnard	BHP Billiton	6.0	Coast Guard accepted application Jan 2004	2008
Crystal Clearwater Port	Offshore	Oxnard	Crystal Energy/ Woodside	6.0	Filed with Coast Guard Jan 2004	2007
Long Beach LNG	Onshore	Long Beach	Sound Energy Solutions	5.3	Filed at FERC Feb 2004	2008
Camp Pendleton	Offshore	Camp Pendleton	Chevron Texaco	5.7	Proposal	–
Baja California, Mexico						
Terminal GNL Mar Adrentro	Offshore	Tijuana	Chevron Texaco	5.3	Filed with Mexican regulators 2003	2007
Energia Costa Azul LNG	Onshore	Ensenada	Sempra Energy/ Shell	7.5	Approved by Mexican authorities	2008

Sources: EIA (2004h); CEC (2004).

als. There are several proposals currently seeking approval, comprising a range of onshore and offshore terminals located in California and Baja California in Mexico (table 96). LNG imports into Baja California could be supplied to the US national grid via existing or new pipelines or used locally. The annual capacity at the proposed terminals ranges from 5.3 million tonnes to 7.5 million tonnes.

The Energy Costa Azul LNG terminal on the coast of Baja California is the first project to receive all three key approvals: a storage and regasification permit from Mexico's national energy regulatory agency, a land use permit and an environmental permit. The terminal is scheduled to receive LNG imports from 2008. The other terminals are at various stages of the approval process by United States and Mexican authorities and are scheduled to be operational during 2007–08.

There is a long lead time associated with the application process for a new LNG import terminal. Results of preliminary studies associated with engineering, safety and environmental assessments, including input through public consultation processes, can take several months or years to complete. Results of the preliminary studies are included with the formal application to the relevant government agencies for authorising LNG construction. Following acceptance of the application, it takes a minimum of 12 to 18 months from the date of filing for a project to be approved (EIA 2004h). As discussed earlier, the FERC, in coordination with the US Department of Transportation and the US Coast Guard has the main responsibility for approving onshore facilities in the United States, while the US Coast Guard and the Maritime Administration oversee permits for offshore facilities. Terminals must also receive state and local government approvals.

Proposed LNG projects in California, as well as other parts of north America, have to date encountered heavy opposition from communities and non-government organisations over proposed sites for terminals, despite economic incentives promised by project developers (EIA 2004h). Local opposition to the construction of LNG terminals has caused several proposed projects to be cancelled, including a planned terminal in northern California in March 2004. Recent analysis of the degree of opposition to LNG terminal proposals in north America has ranked all terminals in California and Baja California in the 'heavy opposition' category (Banaszak and Traxler 2004).

Public concerns are related to the safety of LNG import facilities and tankers and heightened concerns over potential terrorism targets. In an attempt to educate and allay public concerns, the California Energy Commission recently commenced a safety education program for LNG. The visual impact of any LNG facility along the California coastline is also a concern for local residents, because the coast is valued for its natural beauty and recreational opportunities (CEC 2003c,d).

It has been generally considered that the proposed terminals in Baja California in Mexico have a better chance of proceeding than those in California. However, the recent cancellation of the Tijuana project, after the local government expropriated the land on which the group had planned to build their facility, demonstrates that the building and permitting process in Mexico is not necessarily less difficult than in California.

Recent clarifications of the approvals process in the United States may assist in the timely development of terminals on the west coast. FERC recently affirmed that regulatory authority for LNG import terminal siting and construction rests exclusively with the federal government. It is not yet evident, however, if the federal government will overrule state and local opposition to terminal sitings in the national interest. FERC has also reorganised its operations to ensure improved coordination among relevant federal agencies, including the Coast Guard and the Department of Transportation.

Possible LNG import volumes

Given the outlook for strong gas demand growth and high gas prices, LNG imports to the north American west coast in the coming decade are more likely to be limited by the number of terminals and import capacity that is developed than by gas demand and price. In view of the relative size of the local gas market and opposition to terminal siting, it is generally considered that two LNG import terminals might be approved and built in the region by 2015. An alternative scenario is that only one terminal is approved and developed and that capacity at this terminal is expanded, thereby reducing the environmental impacts of terminal development.

LNG imports through west coast terminals are not likely to be limited by available LNG supply, in view of the potentially large number of existing and future sources of LNG in the Asia Pacific market (Neil 2004b). Cargoes of LNG can be sold into the United States market, provided regasified LNG can be delivered at the prevailing market price. Gas prices in California are expected to remain high enough on average to support ongoing LNG imports.

In view of these considerations, it is assumed in the study that two terminals could be built on the north American west coast in the period to 2015, in either California or Baja California (box 10), and that the terminals will import up to proposed average annual capacity. Depending on which terminals are approved and constructed, LNG imports could be between 10 million tonnes and 14 million tonnes in 2015.

Sempra Energy recently signed a sales and purchase agreement with Indonesia's Tangguh project for up to 3.7 million tonnes a year for 20 years from 2008. The LNG will be supplied to the Energia Costa Azul LNG terminal to be located in Baja California. Shell has also signed a 20 year agreement to import 1.6 million tonnes a year from Sakhalin 2 in the Russian Federation from 2008, through the same terminal. Uncontracted LNG demand on the north American west coast is therefore projected to be 4.7 million tonnes in 2015, and 8.7 million tonnes under a high scenario.

Implications for the Asia Pacific market

If import terminal capacity projections are realised, the emergence of an LNG import market on the north American west coast will enhance the outlook for LNG demand in the Asia Pacific region. The location of the new market also provides opportunities for Asia Pacific LNG suppliers, both existing and potential, to access the United States market. These suppliers are currently excluded to a large extent from the east coast because of the long distance and high transport costs compared with traditional Atlantic market suppliers. The west coast, on the other hand, could be more cost effectively supplied by Asia Pacific LNG producers on the basis of transport costs.

All else being equal, LNG from Australia is estimated to take around 18 days to reach the north American west coast, a comparable distance to other suppliers in the region, including Indonesia, Malaysia and Brunei. LNG from the Russian Federation (Sakhalin) is likely to have lower transport costs, as are potential suppliers on the Pacific coast of south America (CEC 2003d; figure 99).

The development of a north American west coast market is likely to increase regional supply flexibility and provide greater opportunities for suppliers to

Box 10: **The role of LNG in Baja California**

Much of this chapter focuses on the US LNG market, particularly the potential in California. Gas demand in Mexico and gas trade between Mexico and the United States, including the effect growing LNG imports into the United States will have on gas supply to Mexico and vice versa, has not been analysed. However, projected imports on the west coast of north American include California and Baja California in Mexico. The integration of gas markets in the region and the current uncertainty over the location of potential LNG terminals makes it difficult to identify the breakdown between the two countries. Depending on the eventual location of terminals, it is likely that LNG will be consumed in both California and Baja California.

Despite significant reserves, Mexico's gas demand has outpaced production in recent years. Gas consumption in Mexico has increased by 5 per cent a year over the past decade, with much of the growth occurring in the power sector. Increased demand has resulted in Mexico importing more gas from the United States via its pipeline network connections, with imports 28 per cent higher in 2003 than in 2002. This trend is expected to continue, with electricity and industry demand for gas forecast to rise strongly. There are plans to develop LNG import facilities on both coasts of Mexico to reduce reliance on imports from the United States and to diversify gas supply sources.

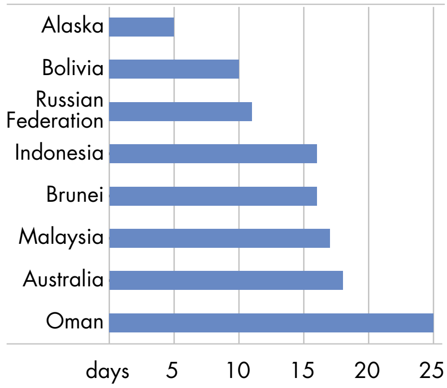
Because Baja California's gas infrastructure is isolated from the rest of Mexico, it is reliant on gas supplies via pipeline from southwestern United States. Baja California currently imports 100 per cent of the gas required for electricity generation from the United States. Natural gas supplies to Baja California from the United States have recently been tight, resulting in price rises in the region. Expected strong growth in the industry and commercial sectors, as well as the rapid development of new gas fired power plants to serve Baja's growing population, makes LNG projects in Baja California an attractive option. Gas demand in Baja California has been projected by the California Energy Commission to triple between 2003 and 2013, to reach 4.4 billion cubic metres (equivalent to 3.2 million tonnes of LNG). The introduction of LNG to Baja California is expected to reduce the region's reliance on US gas imports, provide price competition and increase supply reliability in the region.

As well as LNG terminals, there are also plans to increase pipeline interconnection capacity between the US grid and Mexico, including expanding the North Baja pipeline system connection with southwestern United States. This would allow gas from the proposed LNG terminals in the region to be sold locally in Baja California and exported to the United States.

Sources: EIA (2004i,j); CEC (2003c).

offload surplus cargoes. However, one potential issue for LNG suppliers to the US is that LNG traded in the Asia Pacific region typically has a heat content of more than 1100 Btu per cubic feet — and if untreated could be incompatible with United States market specifications, usually 1035 Btu per cubic feet, plus or minus 50 Btu. LNG can be treated to lower its thermal content, either at the LNG receiving terminal or the liquefaction plant. Options to lower LNG thermal content will incur higher investment costs and higher operating and delivery costs for LNG (Fatica 2004; EIA 2004h).

99 LNG shipping distance to the north American west coast



LNG prices

LNG pricing in the west coast market is expected to be different from traditional Asia Pacific LNG contracts as LNG cargoes into the west coast will be based on the netback to Henry Hub prices. Typically, the delivered/ex ship price of LNG on the west coast will be Henry Hub plus or minus the location premium or discount, minus terminal costs. For LNG suppliers, the fob price will be the delivered price minus the shipping cost.

Such pricing arrangements are more risky for suppliers than those in the traditional Asia Pacific market where prices are less volatile and price floors are often in place. Because of the large investments involved in LNG liquefaction plants, such risks could affect incentives for producers to invest in capacity dedicated to supplying the United States market. To better manage risks, suppliers could opt for a mix of contracts with traditional Asia Pacific and west coast markets. It is understood that there is a clause in the contract between Tangguh and Sempra Energy that would enable Indonesia to divert up to half of the contractual volume each year to other markets in the region if better prices can be obtained (Energy Argus 2004e).

A key question for both buyers and sellers of LNG is whether, in the advent of west coast LNG trade, gas prices in the United States domestic market will be transmitted back to Asia Pacific LNG markets. In particular, will the expected ongoing high Henry Hub prices create upward pressure on LNG prices in the Asia Pacific region?

Because of price arbitrage in the US gas market, gas users will face Henry Hub prices, adjusted for transport differentials. To consumers, the price of LNG will be the same as gas from other supply sources. When domestic gas prices are high, end users will pay high prices, and vice versa. LNG prices for players in the United States market will rise and fall accordingly. The cost of delivering LNG to the United States should remain fairly constant: thus when domestic gas prices are high, profits will accrue to those involved, including suppliers and/or terminal operators.

As long as there is a high degree of competition among potential suppliers of LNG to the west coast, there is unlikely to be significant transmission of high United States gas prices to other Asia Pacific markets. The range of existing and potential LNG suppliers to the Asia Pacific market over the coming decade is likely to ensure that LNG is priced competitively to the north American west coast and other markets, despite the potential significant difference in the delivered cost of LNG and the price of natural gas in the United States.

In addition, the existence of long term LNG contracts in the Asia Pacific market, with volumes fixed and prices dependent on formula, and the large share of the market these importers will maintain, is likely to limit significant transmission of natural gas prices in the United States into the rest of the Asia Pacific market, at least in the coming decade.

At the margin, high gas prices in the United States could attract cargoes that would otherwise go to Asian buyers. However, the distances involved in the supply of Asia Pacific LNG to the west coast and the rigidities associated with many existing LNG supply contracts will make it difficult for LNG suppliers to divert cargoes quickly to take advantage of high prices.

Despite its importance as a new and potentially significant LNG market, the north American west coast is expected to remain a relatively small market in the coming decade compared with others in the Asia Pacific region, including Japan, Korea and China.

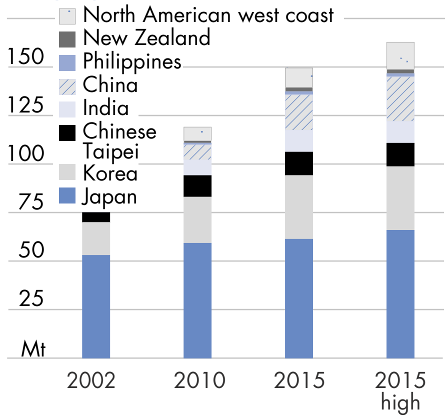
6

potential LNG demand and supply balance

LNG demand in the Asia Pacific region

Based on analysis in the preceding chapters, LNG imports across the Asia Pacific region are projected to expand by 4.8 per cent a year over the period to 2015, underpinned by strong economic growth and a rise in gas fired power generation. By 2010, Asia Pacific LNG imports, including the north American west coast market, are projected to reach 119 million tonnes, rising to 150 million tonnes by 2015 (table 97; figure 100). This compares with the 83 million tonnes of LNG that was traded in 2003.

100 **Projected LNG demand, Asia Pacific**



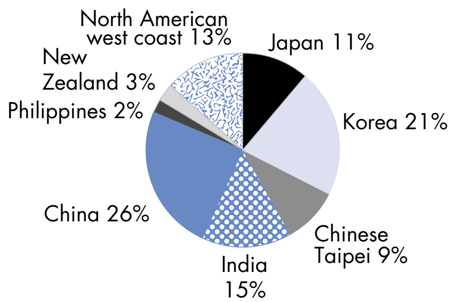
97 **Projected LNG demand, Asia Pacific**

	Imports			Growth	
	2002	2010	2015	2002–10	2010–15
	Mt	Mt	Mt	Mt	Mt
Japan	53.0	59.3	61.4	6.3	2.1
Korea	17.0	23.8	32.9	6.9	9.0
Chinese Taipei	5.1	11.1	12.1	6.0	1.0
India	–	8.1	11.0	8.1	3.1
China	–	7.7	18.3	7.7	10.6
Philippines	–	1.0	1.7	1.0	0.7
New Zealand	–	1.3	2.2	1.3	0.9
North American west coast	–	7.0	10.0	7.0	3.0
Total	75.1	119.2	149.7	44.1	30.5

In a high demand scenario, LNG imports may reach 163 million tonnes in 2015, underpinned by higher than projected GDP growth in Japan, more rapid development of LNG terminals in China following the success of initial projects, and the construction of additional import capacity along the north American west coast. This would approximately double the current LNG demand in the region.

101 Projected share of additional Asia Pacific LNG demand

2002–15



Despite relatively slow projected growth in gas demand, Japan will remain the largest and one of the most important LNG markets in the region, with imports forecast to reach 61.4 million tonnes in 2015. Growth in Japanese LNG imports is projected to account for 11 per cent of new LNG demand in the Asia Pacific region over the period to 2015 (figure 101). Korea is expected to remain the second largest Asia Pacific LNG market over the outlook period, while Chinese Taipei will also continue to be a significant regional destination. LNG imports in Korea and Chinese Taipei are projected to nearly double by 2015, accounting for 21 per cent and 9 per cent of new LNG demand in the Asia Pacific region respectively.

Two of the fastest growing LNG markets in the region will be in the developing economies of India and China, where LNG imports are projected to reach 11 million tonnes and 18 million tonnes respectively by 2015. These two new markets account for about 40 per cent of growth in LNG imports into the Asia Pacific region between 2002 and 2015, with China projected to become the third largest regional LNG destination. Similarly, the development of LNG imports on the north American west coast will also contribute significantly to overall market growth in the Asia Pacific region.

Potential LNG markets in New Zealand and the Philippines are likely to be small in the period to 2015, although New Zealand could represent an important opportunity for Australian LNG suppliers. There is also the potential for other markets in the region to emerge by 2015, including Singapore and Thailand, although these are unlikely constitute a significant share of the regional LNG market during this period (box 11).

Box 11: **Potential additional LNG markets: Singapore and Thailand**

Singapore and Thailand are among several countries in the Asia Pacific region that have recently expressed an interest in introducing LNG imports. Both countries are conducting feasibility studies during 2004 on options to import LNG, but it is unlikely that LNG imports will commence in either country before the end of the decade.

Singapore

Singapore is almost entirely dependent on imported energy. Natural gas consumption has been rising rapidly in Singapore in recent years with the government promoting greenhouse gas emission reduction and energy security policies. Around 60 per cent of Singapore's electricity output is generated from gas, while gas is also used as a feedstock for petrochemical production. Singapore currently imports all of its natural gas through three pipelines: from Malaysia, from Indonesia's west Natuna field, and from Indonesia's Sumatra field.

In June 2004, a disruption to gas supply from the Natuna gas pipeline from Indonesia caused a nationwide power failure for two hours. Previous gas supply incidents occurred in 2003, when a leak in the same pipeline tripped around one quarter of Singapore's power supply, and in August 2002 when a disruption was also followed by blackouts. Such incidents have led to increased interest in introducing LNG to Singapore in order to diversify gas supply sources and enhance gas supply and overall security. However, it is understood that LNG imports would currently cost more than piped natural gas supplies.

The Singapore Energy Market Authority is currently studying the feasibility of importing LNG after 2010, including identifying possible sites for an import terminal. This is understood to be a preliminary study and a final policy promoting LNG imports is expected to be some time away.

Thailand

Thailand currently produces natural gas domestically, as well as importing gas from Myanmar via pipeline. Much of Thailand's gas consumption is for power generation and natural gas demand is expected to rise in the coming years. Further development of Thailand's domestic gas reserves and imports from Myanmar are expected to meet gas demand for the next several years. However, over the longer term Thailand is considering LNG imports as an option to meet rising demand.

The Electricity Generating Authority of Thailand is currently looking at options for LNG imports, with the plans reported to focus on procuring LNG from Iran

continued

Box 11: **Potential additional LNG markets: Singapore and Thailand**
continued

and Oman. The government had previously signed an agreement with Oman in the mid-1990s to import LNG, however, progress was delayed by the Asian economic downturn and burgeoning domestic gas production. Thailand also has a memorandum of understanding with Iran's energy ministry that covers a feasibility study on importing Iranian LNG into Thailand from 2010.

The potential price of LNG into Thailand is reported to currently be uneconomic compared with natural gas piped from local and neighbouring fields. However, Thailand has recently been increasing its emphasis on energy security issues, which could assist in the introduction of LNG to diversify gas supplies.

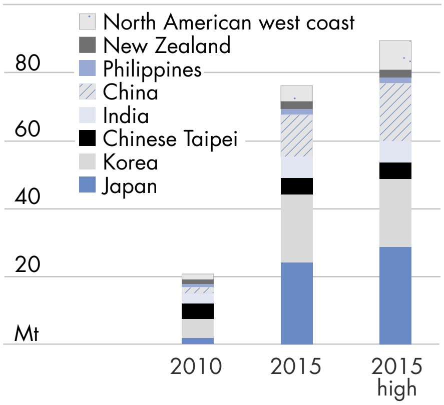
Sources: EIA (2003j, 2004k); Platts (2003i, 2004k,l,m,n).

Uncontracted LNG demand

A significant proportion of future LNG demand in the Asia Pacific region will be met from existing long term LNG supply contracts. By 2010, more than three quarters of projected LNG imports are expected to be met by existing long term contractual supplies. This would leave around 21 million tonnes of LNG imports in 2010 for which new LNG supplies will need to be procured. Much of the uncontracted demand is expected to be in Korea and Chinese Taipei (figure 102; table 98).

By 2015, the proportion of projected LNG demand in the Asia Pacific region that has not yet been contracted is expected to rise to 51 per cent, or around 76 million tonnes, as LNG imports continue to grow and more existing long term LNG supply contracts expire. Japan accounts for nearly one third of projected uncontracted LNG demand in 2015, while significant potential supply shortfalls are also evident in Korea and China. Under the high demand scenario, uncontracted regional LNG demand is

102 Projected uncontracted LNG demand, Asia Pacific



projected to rise to 89 million tonnes in 2015.

However, the share of uncontracted LNG demand, particularly in Japan, is smaller when the scope for contract renewal that exists in the terms of many current long term supply contracts is considered. At least some of the uncontracted LNG demand discussed above will be met by the renewal of existing long term contracts. However, recent reports from some existing importers in Japan, Korea and Chinese Taipei suggest that some proportion of potentially renewable contractual volumes could be genuinely contestable.

98 Projected uncontracted LNG demand, Asia Pacific

	2010	2015	2015 high
	Mt	Mt	Mt
Japan	1.7	24.0	28.6
Korea	5.7	19.9	19.9
Chinese Taipei	4.5	5.0	5.0
India	3.1	6.2	6.2
China	1.8	12.4	17.1
Philippines	1.0	1.7	1.7
New Zealand	1.3	2.2	2.2
North American west coast	1.7	4.7	8.7
Total	20.7	76.2	89.4

As expected, the scope for new long term LNG contracts is greater in the new LNG markets of China, India and the north American west coast, where few existing contracts are in place. In addition, the recent delays in Korea in signing new long term contracts has also led to significant potential supply shortfalls that will need to be met by new LNG contracts.

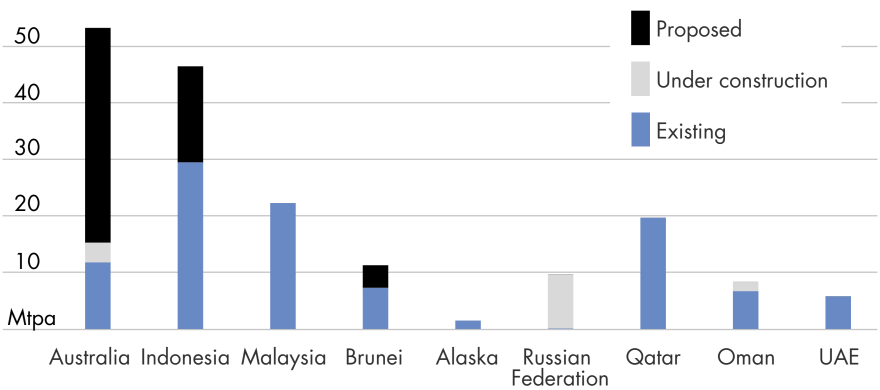
LNG supply to the Asia Pacific region

The outlook for LNG demand in the Asia Pacific region implies a large increase in LNG supplies will be required over the period to 2015. It is expected that the demand for LNG in the Asia Pacific market will continue to be met from within the region as well as from the Middle East. The profile of LNG projects under construction and proposed that could meet Asia Pacific LNG demand suggests that there will be a combination of expansion and greenfield projects from existing and new LNG suppliers.

LNG supply capacity under construction

There is currently an additional 15 million tonnes of LNG capacity under construction that is expected to supply Asia Pacific LNG markets in the next

103 Potential LNG supply capacity for the Asia Pacific market, by country



few years. This figure includes 3.5 million tonnes by 2006 from Darwin LNG in Australia, 9.6 million tonnes by 2008 from Sakhalin 2 in the Russian Federation, and 1.65 million tonnes in capacity for Asia Pacific markets from 2006 from Train 3 in Oman (figure 103). By 2010, regional LNG supply from existing LNG suppliers and those with capacity under construction could be 110 million tonnes. This compares with projected Asia Pacific LNG demand in 2010 of 119 million tonnes.

Proposed LNG supply capacity

There are a further ten projects proposed in existing LNG supplying countries in the Asia Pacific region. Most of these projects are planned to come on line between 2007 and 2011 (figure 104). The proposed projects have a combined annual liquefaction capacity of 59 million tonnes, raising the potential LNG supply capacity to the Asia Pacific market to 169 million tonnes in 2015. The majority of the proposed LNG capacity additions are concentrated

104 Potential LNG supply capacity for the Asia Pacific market

in Australia and Indonesia (table 99; figure 103).

Additional LNG supplies could also be available from the Middle East to supply Asia Pacific markets from the planned significant increases in Qatari capacity. The extent to which supply is switched into the Asia Pacific, if at all, will depend on the realisation of the projected strong growth in LNG imports in the United States east coast market discussed in chapter 5 and in Europe (box 12).

99 Potential LNG supply capacity, Asia Pacific and Middle East

	2004	2010	2015
	Mtpa	Mtpa	Mtpa
Australia	11.7	43.2	53.2
Indonesia	29.4	39.6	39.6
Malaysia	22.2	22.2	22.2
Brunei	7.2	11.2	11.2
Alaska, US	1.4	–	–
Russia	–	9.6	9.6
Qatar	19.6	19.6	19.6
Oman	6.6	8.3	8.3
UAE	5.7	5.7	5.7
Total	103.8	159.4	169.4

Other potential LNG supply capacity

There are also potential suppliers of LNG to the Asia Pacific region that have not been profiled in this study. These potential suppliers — in Iran, Yemen, Peru and Bolivia — do not currently export LNG and do not yet have LNG projects under construction. However, several projects, with a combined annual capacity of more than 50 million tonnes, have been planned in these countries that could begin supply by 2015 (table 100; box 13).

There are some additional uncertainties attached to developing LNG projects in these countries, however, including public opposition, environmental concerns, geopolitical issues, political instability, potential markets and progress in LNG marketing to date. Strong competition among suppliers to secure LNG markets in the Asia Pacific region may make it more difficult for projects such as these to proceed in the next ten years, with buyers taking a range of factors, including price, flexibility, security and reliability, into account when making LNG procurement decisions.

100 Possible additional LNG suppliers to the Asia Pacific market

Country	Project	Capacity	Trains
		Mtpa	no.
Peru	Peru LNG	4.0	1
Bolivia	Pacific LNG	7.0	–
Iran	Iran LNG	8.0	2
Iran	NIOC LNG	8.0	2
Iran	Pars LNG	10.0	2
Iran	Persian LNG	10.0	2
Yemen	Yemen LNG	6.2	3

Box 12: **Outlook for European LNG demand**

Natural gas is expected to be the fastest growing fuel consumed in western Europe in the coming decades. Much of the growth in demand will stem from the increasing use of gas in power generation. Europe currently holds less than 4 per cent of the world's proven recoverable natural gas reserves and the region is expected to become increasingly dependent on gas imports. The distance of potential pipeline gas suppliers to Europe means that LNG could become a more important source of imports, and Europe is expected to be a significant growth market for LNG over the coming decade.

Currently, the primary sources of natural gas imports to Europe are pipelines from the Russian Federation and Algeria, and LNG from various sources. In 2003, there were seven importers of LNG in Europe — Spain, France, Italy, Turkey, Belgium, Portugal and Greece — and regional imports were 40 million tonnes. This compares with three countries importing 3.8 million tonnes in 1980. LNG imports in the region have been growing at a faster rate than in the Asia Pacific market, at more than 9 per cent a year since 1980.

Europe currently has 12 operating LNG import terminals: four in Spain, two in France and Italy, and one each in Belgium, Greece, Portugal and Turkey. Considerable infrastructure development is planned in the next few years to increase regional LNG import capacity.

Rising LNG demand in Europe reflects a range of factors. In addition to a lack of indigenous regional gas supplies, these include buyers seeking diversity of supply for security reasons: the Spanish government, for example, has legislated to limit gas from a single source to 60 per cent of the market. Pipeline capacity is constrained, especially in supplying gas markets in southern Europe. In addition, with the current tariff structures, gas from the north is constrained from effective competition in southern Europe by high transit costs.

Key future drivers of European LNG demand include developments in Spain and the United Kingdom. Spain is considered one of the world's most rapidly growing natural gas markets, and is in the process of phasing out its older nuclear and coal fired power plants in favor of gas. Spain is almost entirely dependent on imports and it received 59 per cent of its gas imports as LNG in 2002. In the United Kingdom, the share of gas in power generation is projected to reach almost 50 per cent by the end of the decade. Faced with a potential gas supply shortfall, the United Kingdom is looking to reintroduce LNG imports to its gas market.

Sources: EIA (2004j); IEA (2002); Flower and King (2002).

Box 13: **Possible additional LNG suppliers to Asia Pacific markets**

Additional projects have been proposed to supply LNG to the Asia Pacific region by 2015. These include several proposed projects in Iran, and projects in Yemen, Peru and Bolivia, all countries that do not currently export LNG and do not yet have LNG projects under construction. The proposed projects have a combined annual liquefaction capacity of more than 50 million tonnes.

Iran

With the world's second largest proven recoverable gas reserves, Iran has significant potential for LNG export development. There are up to four LNG export projects that have been proposed in Iran based on the South Pars Field (the same field as all Qatari LNG projects): NIOC LNG, Iran LNG, Pars LNG and Persian LNG. Each proposed project consists of a two train, 8–10 million tonne a year liquefaction plant located at Assulayeh. Possible start dates for the projects have been announced by the Iranian government as 2008 and beyond.

Potential LNG markets for Iran include Europe and Asia. While it is likely that some projects will be targeted at European markets, Iran's location suggests that significant volumes of LNG could also be exported to Asia, particularly to India. There have been recent reports of preliminary LNG sales agreements between Iran and India and China.

Uncertainties relating to long term investment in Iran and a reported lack of coordination between upstream and downstream gas sectors have to date hindered the marketing and realisation of Iranian LNG projects. In addition, significant volumes of natural gas designated for export could be required for injection into maturing oil fields to stabilise oil production.

Yemen

There is currently no production of natural gas in Yemen. From the mid-1990s, potential natural gas sector development in Yemen have been primarily focused on the export of LNG. More recently, possible natural gas production for domestic use in the electricity and petrochemical sectors has also been considered.

The Yemen LNG project includes a two train, 6 million tonne a year liquefaction plant on the south coast of Yemen. However, there has been little progress to date in securing long term LNG sales. Difficulties have included withdrawal of some multinational ownership, strong regional competition, high internal transport costs and security concerns. In recent years, the project has bid to supply China, India and Korea, including the current KOGAS contract negotiations. The Yemeni government has given the project until mid-2006 to find markets.

continued

Box 13: **Possible additional LNG suppliers to Asia Pacific markets**
continued

Peru

There are currently plans to export LNG from Peru to the north American west coast market. The proposed project, Peru LNG, would be located south of Lima at Pampa Malchorta, and is based on Peru's Camisea fields. The single train plant of 4.4 million tonnes in annual liquefaction capacity is currently scheduled to be on line by late 2007 or early 2008.

Discussions regarding potential markets for Peruvian LNG are ongoing. To date, there is a preliminary agreement to sell 2.7 million tonnes of LNG a year for 18 years to Tractebel to supply its planned regasification terminal at Lazaro Cardenas, west of Mexico City. However, the Mexican government has since awarded the terminal concession to another entity and it remains unclear whether Tractebel will propose a new terminal site. In addition, while an environmental impact study has been completed, the project faces opposition on environmental grounds because the planned pipeline would run through sections of Peruvian rainforest and the liquefaction plant would be located near a wildlife sanctuary.

Bolivia

Bolivia is considering exporting LNG to the north American west coast from the Margarita field. The proposed Pacific LNG project consists of a 7 million tonne a year liquefaction plant. However, Bolivia does not have coastal access, so gas would need to be piped to the coast to an LNG plant located in Chile or Peru. Although building the pipeline through Chile is shorter than through Peru and thus more cost effective, a long standing territorial issue between Bolivia and Chile makes the route politically unpopular in Bolivia. In October 2003, the Bolivian population protested heavily against the government's plan to export gas through Chile, which contributed to the resignation of the President at the time.

The Pacific LNG project is now on hold and it remains unclear when and if the project will be developed. However, the current government has publicly supported the Peruvian option and a referendum on the issue in July 2004 has resulted in public agreement for LNG exports to proceed. The delays, ongoing civil unrest and the fall of the government have to date hindered the marketing of Bolivian LNG.

Sources: EIA (2003k, 2004j,l,m); FACTS Inc. (2004d); Platts (2004o,p,q); Energy Economist (2004b,c)

Timing of new LNG supply capacity

As discussed in chapter 4, LNG projects are not likely to come on line until there is sufficient demand to underpin the required investment. Indeed, a number of the projects proposed to be on line by the end of the decade have already been marketed for several years and their development date postponed to enable LNG markets to be secured. For example, the Tangguh LNG project in Indonesia was originally scheduled to commence exports in 2003, but the difficulties in securing a long term buyer have led to the timing of its development being revised on several occasions (BG 1998). The plant is currently scheduled to begin operations in 2008.

Given that the outlook for LNG demand in the Asia Pacific region is projected to be lower than the total of all potential LNG supply projects, firm sales contracts for all projects are unlikely to materialise by their proposed start up dates. Reflecting this, it is anticipated that some of the proposed projects discussed in the study are likely to be delayed, and some projects may not come on line at all in the period to 2015.

In view of this, competition to supply the Asia Pacific LNG market is expected to be strong at the project development stage in order to secure markets to launch projects. Ongoing supply competition, combined with changing market conditions in the region, are likely to lead to continued advances in flexibility in LNG supply contracts. Delays in project approval processes, including as a result of environmental and boundary issues, could result in start up dates for some projects postponed for several years as potential market opportunities are captured by other suppliers.

As in the past, the actual development of regional LNG export capacity is not expected to be far ahead of demand in the coming decade. Indeed, LNG supply in the next few years is likely to be tight in the Asia Pacific market, particularly to meet unexpected demand, as few projects are expected on line in this period and supply from proposed projects will take some years to become available.

Options for pipeline natural gas imports

A potential source of competition for LNG imports is the development of further pipeline natural gas infrastructure in the Asia Pacific region. Compared with north America and Europe, there are few cross border natural gas pipelines in the Asia Pacific region, although some countries have developed international pipeline infrastructure in recent years. The following international pipelines are currently operating in the Asia Pacific region:

- from Malaysia to Singapore;
- from Myanmar to Thailand;
- from west Natuna in Indonesia to Singapore;
- from south Sumatra in Indonesia to Singapore; and
- from Natuna in Indonesia to Malaysia (Suzuki and Morikawa 2003).

There are several possibilities for additional international gas pipelines in the Asia Pacific region that could compete with LNG trade, including from various locations in the Russian Federation to China, Japan and Korea; from Bangladesh and Iran to India, and among several ASEAN countries (figure 105). The development of international pipeline natural gas infrastructure in the region will have implications for the outlook for LNG demand. However, issues relating to the development of international pipelines in the Asia Pacific region, including market size, competitiveness with LNG, and geopolitical issues are unlikely to be resolved in time to allow the pipelines to be in place and operational by 2015 (Wybrew-Bond and Stern 2002).

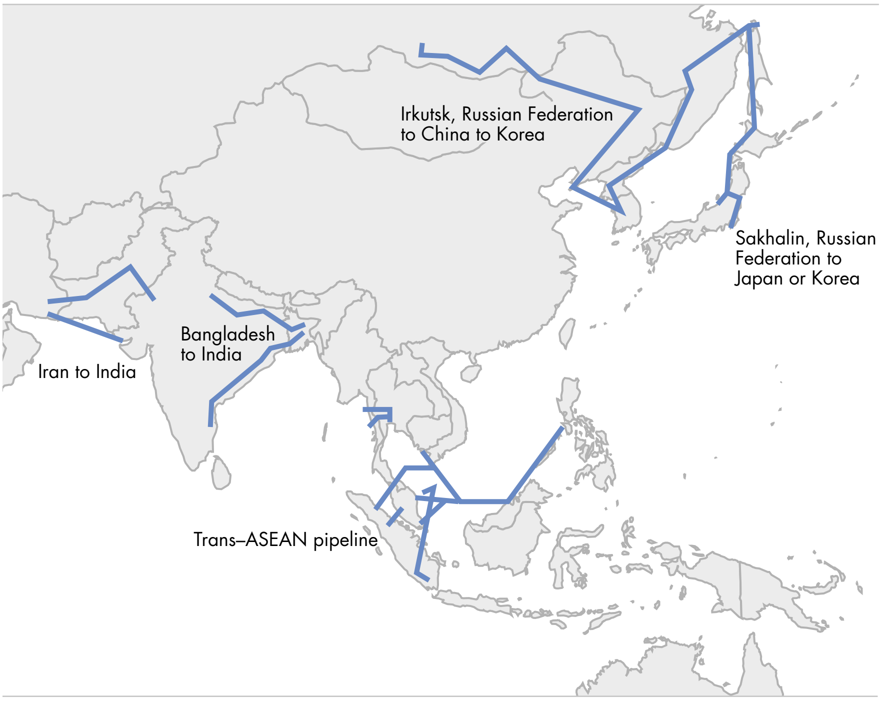
Potential international gas pipelines in the Asia Pacific

Irkutsk, Russian Federation to China and Korea

The Russian Federation, China and Korea have recently conducted a joint feasibility study regarding the supply of pipeline natural gas from the Kovykta field, in the eastern Siberian province of Irkutsk, to China and Korea. After several years of discussion, the results of the feasibility study were finalised in November 2003.

The proposed pipeline route is around 4100 kilometres in length, overland from Kovykta in eastern Siberia through northeastern China then via a subsea pipeline from Dalian to Pyeongtaek, near Seoul. The Korean Ministry of Finance and Economy has estimated the total cost of the pipeline project to be US$11 billion, although estimates that include field development are as high as US$18 billion (Reuters 2003).

105 Potential international gas pipelines that could compete with LNG, Asia Pacific region



The volume of natural gas supplied to China is expected to be equivalent to 15 million tonnes a year for 30 years, while the volume to Korea could reach 7 million tonnes a year. Provisional gas sales agreements have been signed, but it is understood that there has been some difficulty in reaching an agreement between all parties on gas prices.

The target start up date for international gas supply from Irkutsk is 2008–10. However, this date is looking increasingly unlikely for a number of reasons. The construction of the pipeline would take a number of years to complete and would therefore need to begin quickly to be operational within this timeframe. The viability of the project depends to a large extent on China, including both its potential natural gas demand and infrastructure priorities. China has been investing large amounts of capital in its west to east gas pipeline and there are questions regarding China's willingness to commit to two large pipeline projects this decade. There are also reports that China's policy makers have a preference to utilise domestic gas supplies and imported LNG and would be unlikely to commit to Russian pipeline gas before 2015. There may also be pressure from Gazprom in the Russian Federation to use gas from Kovykta to supply the domestic gas market (Platts 2003a,b; WMRC 2004). Given the uncertainties associated with the project, it is likely that the earliest the Irkutsk pipeline could deliver gas is early next decade, with a possible startup date after 2015 (Ball et al 2003; Wybrew-Bond and Stern 2002).

If the pipeline does proceed before 2015, it is likely to displace LNG imports in Korea over the outlook period. However, there would still be a requirement for significant volumes of LNG to the Korean market: by 2015 uncontracted LNG demand in Korea is 13 million tonnes with the Irkutsk pipeline, and 20 million tonnes in its absence (Ball et al. 2003). The pipeline is unlikely to affect LNG imports to China over the outlook period, as Irkutsk gas would be supplied to northern Chinese markets and possibly Beijing, while LNG imports are likely to be concentrated in the southern coastal regions. With little national gas infrastructure to link the two regions and the significant distances involved in gas transport, LNG is likely to be a cheaper source of gas in this region of China (Schneider et al. 2003).

Sakhalin, Russian Federation to Japan

The Sakhalin 1 development on Sakhalin Island in the Russian Federation's far east has been dedicated to pipeline natural gas for export. Japan is the principal market for the pipeline project. A US$15 billion project has been proposed to build a 1900–2200 kilometre subsea pipeline that would supply the equivalent of around 6 million tonnes of natural gas a year to the Niigata or Tokyo areas in Japan from 2008. The project was declared feasible in 2002 (Platts 2003b; Energy Argus 2003).

It is unlikely, however, that Japan's gas market, with its emphasis on LNG and lack of an interconnected national pipeline network, will absorb the minimum volume of pipeline gas required for the project to be viable in the scheduled timeframe of 2008. This view is reinforced by the recent LNG import commitments by four Japanese companies from the nearby Sakhalin 2 LNG development. It is generally considered that the Sakhalin 1 pipeline project will not be able to proceed until there is sufficient market growth in Japan and this is unlikely to occur by 2015 (EIG 2003b; Platts 2003j).

While it has been suggested that gas from Sakhalin 1 could be redirected or extended to Korea to enhance the viability of the pipeline, there are no well developed plans at this stage. A further option reported to be under consideration is a pipeline to the Russian Federation mainland to serve the domestic market in the far east, with a further extension to China also possible (FACTS Inc. 2003c; Platts 2003b,k).

Trans-ASEAN pipeline

There is also a potential development in the region known as the Trans-ASEAN pipeline project, which aims to link eight major gas consuming areas: Thailand, Malaysia, Singapore, Indonesia, Brunei, the Philippines, Myanmar and Vietnam. In 2002 ASEAN ministers signed a memorandum of understanding regarding the implementation of the project.

Several regional gas pipelines have been completed to date, including connections between Singapore, Malaysia and Indonesia, and between Myanmar and Thailand. Several other pipelines are under construction or are being considered (table 101). It is envisaged that all pipelines would be commissioned by 2020, to form the Trans-ASEAN pipeline network. The cost of constructing the total network has been estimated at US$7 billion (Roberts et al. 2003).

101 Status of ASEAN gas pipelines

Country of origin	Country of destination	Date commissioned
Malaysia	Singapore	1991
Myanmar (Yadana)	Thailand (Ratchaburi)	1999
Myanmar (Yetagun)	Thailand (Ratchaburi)	2000
Indonesia (West Natuna)	Singapore	2001
Indonesia (West Natuna)	Malaysia (Duyong)	2002
Indonesia (Grissik)	Singapore	2003
Thailand (Joint Development Area)	Malaysia	Scheduled 2005
Indonesia (South Sumatra)	Malaysia	Scheduled 2005
Indonesia (Arun)	Malaysia	Scheduled 2010
Indonesia (East & West Natuna)	Malaysia (Kerteh) and Singapore	Scheduled 2010
Indonesia (East Natuna)	Thailand (JDA–Erawan)	Scheduled 2012
Indonesia (East Natuna)	Malaysia (Sabah) and Philippines (Palawan–Luzon)	Scheduled 2015
Malaysia–Thailand (JDA)	Vietnam (Block B)	Scheduled 2016

Source: Roberts et al. (2003).

The development of the Trans-ASEAN pipeline network could affect the scope for LNG imports in Thailand, Singapore and the Philippines in the period to 2015 and beyond. It may also shift the focus of future gas exports from Malaysia and Indonesia somewhat to regional pipelines rather than LNG.

Bangladesh to India, Iran to India

India is located close to a number of countries with large gas reserves, providing a range of competitive opportunities to import gas via pipeline. However, the development of gas pipelines to India to date has been stalled by geopolitical tensions in the region.

One pipeline option currently under consideration is from neighboring Bangladesh. The planned pipeline would be 1360 kilometres in length and deliver gas to India equivalent to 3.8 million tonnes of LNG a year (FACTS Inc. 2003d). However, the Bangladeshi government has so far been reluctant to approve gas exports to India until all questions about its reserves and domestic supply security have been resolved (EIA 2004c).

Another option is a pipeline from Iran, either overland through Pakistan or via a direct subsea pipeline. It is believed the cost of the subsea pipeline is likely to be prohibitive, which leaves only the Pakistani route as economically feasible (IEA 2002). The pipeline would be 2500 kilometres in length with a capacity equivalent to 7.7 million tonnes of LNG. Iran and Pakistan are reported to be proceeding with their portion of the pipeline, however, to date India has been reluctant to commit to the project on the grounds of supply security and geopolitical issues (Aspermont 2004a). Improved relations between India and Pakistan could accelerate development of the pipeline, but the project would take several years to be operational.

In terms of price, pipeline gas import options for India are believed to be superior to LNG imports (Gail-Infraline 2003). It is likely therefore that the development of pipeline gas imports could displace potential LNG imports in India. However, until energy security and political tensions surrounding pipeline gas imports are resolved, it is likely that all of India's gas import needs will continue to be met by LNG.

LNG and international pipelines

The development of further pipeline natural gas imports in the Asia Pacific region will depend to a large extent on the competitiveness of pipeline gas with LNG. Other factors such as energy security, supply diversity, regional cooperation and geopolitical issues will also play a role.

Distance and volume are the key variables that affect the unit cost of transporting LNG and pipeline gas. For both forms of transport, unit costs increase with distance and decrease with the volume of gas being transported. Over shorter distances, pipelines tend to be the more cost effective form of gas transport. The point at which transporting LNG via tanker is cheaper than transporting natural gas via pipelines occurs at a distant of around 2000 kilometres for offshore pipelines, and around 3800 kilometres for onshore pipelines (EIA 2003b). However, while some pipelines fall within a cost effective distance for the purpose of transport, there are considerable political and economic problems associated with their construction over the medium term.

There are other reasons why LNG might be preferred over pipeline supply options. These include the fact that LNG supply can be more flexible — smaller amounts of gas usually can be delivered more cost effectively by LNG than by pipeline. This means that LNG projects can build delivery capacity in line with an expanding market whereas pipelines will be underutilised and potentially uneconomic until maximum capacity is reached. In addition, construction and delivery lead times tend to be shorter for LNG projects than for major pipelines. This can have a positive impact on the risk profile of a project and hence on the ability to raise the necessary project finance.

In the case of international pipelines, political risks associated with transiting other countries can increase the costs of project development, whereas the flexibility of LNG supplies largely avoids geopolitical sensitivities. It is likely to be easier to avoid disruptions to gas supplies in instances of political instability in the exporting country — as seen in 2001 when the Arun plant in Indonesia was shut down for several months — and to source additional LNG supplies (Wybrew-Bond and Stern 2002).

7

conclusions

Demand for LNG has grown strongly in recent years, particularly in the Asia Pacific region where LNG is the primary source of gas in some countries. Contributing factors include increased emphasis on environmental issues, the uptake of cost effective technologies such as combined cycle gas power plants, the falling costs of LNG supply, and the commercialisation of abundant gas reserves. Energy security and fuel diversification policies have also played an important role in encouraging gas demand as a means of reducing dependence on imported oil.

The outlook for LNG demand in the region is also strong, with Asia Pacific LNG demand projected to nearly double by 2015, from around 83 million tonnes in 2003 to 150 million tonnes in 2015, or 163 million tonnes under a high growth scenario. The majority of Asia Pacific LNG consumption will continue to be in the three established LNG markets: Japan, Korea and Chinese Taipei. While the rate of growth in LNG imports in Japan is expected to slow, it will remain the largest and one of the most important markets in the region. LNG imports in Korea and Chinese Taipei are projected to almost double, supported by robust economic growth and an increasing emphasis on gas fired power generation.

Strong growth is also anticipated in the emerging LNG markets of India and China, as both countries seek LNG imports to complement existing domestic gas supplies and to fuel expected rapid growth in economic output and electricity generation, and to increase the use of clean energy sources. While LNG imports have recently commenced in India, the outlook for LNG will depend on large scale development of gas fired electricity infrastructure and the addressing of the presently unfavorable pricing arrangements for LNG. In China, the outlook for LNG imports from 2006 is more positive, with government support for developing LNG terminals and associated gas fired power stations in the rapidly growing eastern coastal region of China. In both countries, the prospects for LNG imports in the medium term will be heavily influenced by the success of initial projects.

Potential new LNG markets are also emerging in the Philippines and New Zealand, as well as in Singapore and Thailand. While demand in these countries will be small in the timeframe considered in this study, the development of new LNG markets offers the opportunity for suppliers to establish foundation contracts across a more diverse range of countries.

The potential scale of LNG imports along the north American west coast remains one of the largest uncertainties in the Asia Pacific market outlook in the coming decade. Driving interest in LNG imports are high gas prices in the United States, growth in demand for gas fired power generation, expected shortfalls in future north American gas supplies, including from Canada, and the increasing competitiveness of LNG in the United States gas market. However, the establishment of LNG trade will depend on overcoming strong public opposition to the siting of the several LNG terminals currently proposed in both California and Baja California in Mexico. It is generally considered that there could be up to two north American west coast LNG terminals by 2015, with imports limited more by import terminal capacity and gas prices than by demand.

LNG suppliers have shown strong interest in the new market and competition to supply this region is likely to be intense. However, returns to suppliers are expected to be more volatile and thus more risky than elsewhere in the Asia Pacific market. While LNG supply volumes are being fixed in long term contracts, prices are expected to be based on the netback from US gas prices, and it could be difficult for suppliers to base project investment decisions solely on the US market.

The outlook for LNG demand in the Asia Pacific region will provide both opportunities and challenges for LNG suppliers. Not all projected LNG demand will be met by existing supply. In addition to new market growth, a number of significant existing long term contracts will expire in the next ten years: by 2015 it is projected that there could be up to 76 million tonnes of uncontracted LNG demand in the region. The largest uncontracted demand will be in Japan, Korea and China.

Some demand will be met by renewal of existing long term LNG supply contracts, but a significant proportion of uncontracted demand is expected to be genuinely contestable. Competition to retain market shares among existing LNG suppliers will be strong, although there will be a key role for new suppliers as well. A near doubling of liquefaction capacity will be required by 2015 to meet projected demand. This compares with the more than thirty years it has taken to reach current capacity levels and implies a major investment commitment.

There are many proposed LNG projects to meet regional demand, both in existing and new supplying countries. However, because of the large capital requirements involved in LNG projects, many of the proposed projects will not proceed until markets have been secured. The development of some recent projects, including Sakhalin 2 in the Russian Federation, without significant initial long term supply contracts in place is likely to be the exception rather than the rule.

Ongoing supply competition, combined with changing market conditions in the region, means there will be continued pressure on suppliers to provide flexible, competitive LNG supply contracts. Delays in project approval, including as a result of environmental and boundary issues, could see start up dates postponed for several years as potential market opportunities are captured by other suppliers. As in the past, actual LNG supply is unlikely to get far ahead of demand in the coming decade. Indeed, LNG supply in next few years may be tight in the Asia Pacific market, as few projects are expected online in this period and supply from proposed projects will take some years to become available.

Australia is one of the largest potential suppliers of LNG to the Asia Pacific region, with several proposed projects over the coming decade that could more than quadruple Australian LNG supply capacity. As with other projects in the region, Australia will face strong competition to secure markets in this timeframe, including from Indonesia and the Middle East. However, with LNG buyers taking into account price, flexibility, diversity, political security and reliability when making purchasing decisions, the outlook for the Australian LNG industry in the coming decade remains strong.

references

ABARE 1996, *The MEGABARE Model: Interim Documentation*, ABARE, Canberra.

ADB (Asian Development Bank) 2003, *Asian Development Outlook 2003*, Oxford University Press, Hong Kong.

ALNG (North West Shelf Australia LNG) 2004, website, various pages, Perth (www.nwsaustralialng.com.au).

Aspermont 2004a, 'Minister: Iran and Pakistan to go ahead without India … for now', *EnergyReview.Net,* Perth, 23 March.

—— 2004b, 'GNPower to build Philippines first LNG terminal', *Energy Review.Net*, Perth, 6 April.

—— 2004c, 'LNG is viable for NZ: Contact, Genesis', *EnergyReview.Net*, Perth, 16 November.

—— 2004d, 'BP Migas to build LNG terminal', *EnergyReview.Net*, Perth, 10 May.

—— 2004e, 'Petronas chief: LNG capacity can lift by 17%', *EnergyReview. Net*, Perth, 13 February.

—— 2004f, 'Qatar to triple LNG output', *EnergyReview.Net*, Perth, 25 March.

Bainbridge, K. 2004, 'World markets speeding change for LNG shipping', *Oil & Gas Journal Online*, 3 May.

Ball, A., Schneider, K., Melanie, J., Curtotti, R., Changwon Park, Jaesung Kang and Jaekyu Lim 2003, *LNG in Korea: Opportunities for Growth*, ABARE and KEEI, ABARE Research Report 03.4, Canberra.

Banaszak, S. and Traxler, F. 2004, 'Public resistance narrowing LNG options in North America', *Oil & Gas Journal Online*, 14 June.

Banerjee, P. 2003, Indian gas scenario: emerging business opportunities and environmental concerns, Keynote address (KA 1-7), 22nd World Gas Conference, Tokyo, 5 June.

BG Group 1998, 'BG plc/ARCO announce doubling of proven reserves for Indonesia's Tangguh LNG Project', Media release, Berkshire, United Kingdom, 18 August (www.bggroup.com).

BHP Billiton 2004, 'BHP Billiton announces preferred site for proposed LNG plant', Media release, Melbourne, 2 September (www.bhpbilliton.com).

BLNG (Brunei LNG) 2004, website, various pages, Lumut (www.blng.com.bn).

BP various years, *BP Statistical Review of World Energy*, BP, London.

Brinded, M. 2003, Shared trust – the key to secure LNG supplies, Presenation to US LNG Summit, Washington DC, 17 December.

Burg, G., Richmond, S., Haine, I. and Maurer, A. 2004, 'Energy', *Australian Commodities*, vol. 11, no. 3, September quarter, pp. 419–29.

CEC (California Energy Commission) 2003a, *State of California – Energy Action Plan*, Sacramento, May (www.energy.ca.gov).

—— 2003b, *Electricity and Natural Gas Assessment Report*, Sacramento, December (www.energy.ca.gov).

—— 2003c, *Natural Gas Market Assessment Report*, Sacramento, August, (www.energy.ca.gov).

—— 2003d, *LNG Overview*, Sacramento, September (www.energy.ca.gov/lng/documents/index.html).

—— 2004, *Description and overview of West Coast LNG projects*, Sacramento, September (www.energy.ca.gov/lng/projects.htm)

CNEB (Canada National Energy Board) 2003, *Canada's Energy Future: Scenarios for Supply and Demand to 2025,* Calgary (www.neb.gc.ca).

ConocoPhillips 2004, 'ConocoPhillips announces first liquids production from Bayu-Undan', Media release, Houston, 13 February (www.conocophillips.com).

CPC (Chinese Petroleum Corporation) 2002, *Taiwan LNG Prospects*, Taipei.

DISR (Australian Government Department of Industry, Science and Resources) 2000, *Liquefied Natural Gas Action Agenda 2000*, Canberra, October (www.industry. gov.au/assets/documents/itrinternet/LNGAA.pdf).

DITR (Australian Government Department of Industry, Tourism and Resources) 2004, *Liquefied Natural Gas Action Agenda*, Canberra, March (www.industry.gov.au).

DOE (Philippines Department of Energy) 2003, *Power Development Program (Power Supply Plan): Result of PDP (2004-2013)*, Manila.

East-West Center 2004, An overview of the APEC LNG markets and their evolving contract structure, Background paper for the APEC Workshop on LNG Best Practices, Honolulu, April.

EIA (Energy Information Administration) 2003a, *State Energy Data 2000 Consumption*, Washington DC, September (www.eia.doe.gov/emeu/states/_use_multistate.html).

—— 2003b, *The Global Liquefied Natural Gas Market: Status and Outlook*, Washington DC, December (www.eia.doe.gov/oiaf/analysispaper/global/pdf/eia_0637.pdf).

—— 2003c, Japan, *Country Analysis Briefs*, Washington DC, July (www.eia.doe.gov/emeu/japan.html).

—— 2003d, Brunei, *Country Analysis Briefs*, Washington DC, July (www.eia.doe.gov/emeu/cabs/brunei.html).

—— 2003e, Qatar, *Country Analysis Briefs*, Washington DC, November (www.eia.doe.gov/emeu/cabs/qatar.html).

—— 2003f, Oman, *Country Analysis Briefs*, Washington DC, October (www.eia.doe.gov/emeu/cabs/oman.html).

—— 2003g, *Annual Energy Review 2002*, Washington DC, October (www.eia.doe.gov/emeu/aer/contents.html).

—— 2003h, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2002 Annual Report*, Washington DC, December (www.eia.doe.gov).

—— 2003i, *US LNG markets and uses*, Washington DC, January (www.eia.doe.gov).

—— 2003j, Thailand, *Country Analysis Briefs*, Washington DC, October (www.eia.doe.gov/emeu/cabs/thailand.html).

—— 2003k, Bolivia, *Country Analysis Briefs*, Washington DC, October (www.eia.doe.gov/emeu/cabs/bolivia.html).

—— 2004a, Natural gas navigator, various pages, Washington DC (tonto.eia.doe.gov/dnav/ng/ng_sum_top.asp).

—— 2004b, *State Electricity Profiles 2002*, Washington DC, February (www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html).

—— 2004c, India, *Country Analysis Briefs*, Washington DC, June (www.eia.doe.gov/emeu/india.html).

—— 2004d, Indonesia, *Country Analysis Briefs*, Washington DC, July (www.eia.doe.gov/emeu/cabs/indonesa.html).

—— 2004e, United Arab Emirates, *Country Analysis Briefs*, Washington DC, February (www.eia.doe.gov/emeu/cabs/uae.html).

—— 2004f, Russia, *Country Analysis Briefs*, Washington DC, May (www.eia.doe.gov/emeu/cabs/russia.html).

—— 2004g, *Annual Energy Outlook – 2004*, Washington DC, (www.eia.doe.gov/oiaf/aeo).

—— 2004h, *US LNG Markets and Uses: June 2004 Update*, Washington DC (www.eia.doe.gov).

—— 2004i, Mexico, *Country Anaylsis Briefs*, Washington DC, March (www.eia.doe.gov/emeu/cabs/mexico.html).

—— 2004j, *International Energy Outlook 2004*, Washington DC, April (www.eia.doe.gov/oiaf/ieo/index.html).

—— 2004k, Singapore, *Country Analysis Briefs*, Washington DC, May (www.eia.doe.gov/emeu/cabs/singapor.html).

—— 2004l, Yemen, *Country Analysis Briefs*, Washington DC, July (www.eia.doe.gov/emeu/cabs/yemen.html).

—— 2004m, Peru, *Country Analysis Briefs*, Washington DC, May (www.eia.doe.gov/emeu/cabs/peru.html).

Energy Argus 2003, 'Tokyo Gas warms to Sakhalin Energy', *Asia Gas & Power*, 12 February, p. 8.

—— 2004a, 'LNG reaches India', *Asia Gas & Power*, 21 January, p. 4.

—— 2004b, 'Upstream firm ventures into power', *Asia Gas & Power*, 28 June, p. 9.

—— 2004c, 'Domestic gas struggles to meet demand', *Asia Gas & Power*, 12 May, pp.10–11.

—— 2004d, 'Pertamina consolidates export role', *Asia Gas & Power*, 12 May, p. 8.

—— 2004e, 'Sempra deal clears the way', *Asia Gas & Power*, 13 October, p. 5.

Energy Commission 2003, *The Energy Situation in Taiwan, Republic of China*, Ministry of Economic Affairs, Taipei, March.

Energy Economist 2003, 'New Zealand pins its hopes on new finds', *Energy Economist*, no. 263, September, pp. 15–20.

—— 2004a, 'Transportation troubles for Russia's Gazprom', *Energy Economist*, no. 270, April, pp. 8–13.

—— 2004b, 'Bolivia faces the new year without a rosy gas future', *Energy Economist*, no. 268, February, pp. 3–6.

—— 2004c, 'Bolivian gas referendum victory could speed Southern Cone regional gas integration', *Energy Economist*, no. 275, September, pp. 11–14.

EIG (Energy Intelligence Group) 2003a, 'Market insight: Asian swaps', *World Gas Intelligence*, 8 December.

—— 2003b, 'Shell's Sakhalin successes', *World Gas Intelligence*, 21 May.

FACTS Inc. 2003a, *Pacific Gas Insiders 2003*, Singapore, 11–12 December.

—— 2003b, 'Indonesia's natural gas fundamentals and forecasts: an overview', *Gas Advisory*, no. 20, Singapore, July.

—— 2003c, ‘Future scenarios for Korean gas business’, *Gas Insights*, no. 20, Singapore, May.

—— 2003d, ‘India’s natural gas fundamentals and forecasts: an overview’, *Gas Advisory*, no. 19, Singapore, June.

—— 2004a, *Gas Databook 1: Asia-Pacific Natural Gas & LNG*, Hawaii.

—— 2004b, ‘India: gas business comes of age, *Gas Insights*, no. 30, Singapore, February.

—— 2004c, ‘Philippines: gas needs and LNG import prospects’, *Gas Insights*, no. 32, Singapore, April.

—— 2004d, ‘Iran’s gas industry: an update’, *Gas Insights*, no. 33, Singapore, July.

Fairhead, L., Melanie, J., Holmes, L, Ye Qiang, Ahammed, H. and Schneider, K. 2002, *Deregulating Energy Markets in APEC: Economic and Sectoral Impacts*, APEC#202-RE-01.3, ABARE Research Report 02.5, Canberra.

Fatica, A. 2004, ‘Gas-quality debate heats up as more US LNG imports loom’, *Oil & Gas Journal Online*, 14 June.

FEPC (Federation of Electric Power Companies of Japan) 2004, Electricity generated and purchased (bulletin), Tokyo (www.fepc.or.jp).

Flower, A. and King, R. 2002, *LNG Today: the Promise and the Pitfalls*, Energy Publishing Network, Didcot, United Kingdom.

GAIL-Infraline 2003, *Natural Gas in India: a Reference Book*, Infraline Technologies (India) Private Limited, New Delhi (www.infraline.com).

Genesis 2004, ‘Leading NZ energy companies team up to explore LNG potential’, Media release, 28 January (www.genesispower.co.nz).

Geoscience Australia 2004, *Oil and Gas Resources of Australia 2002*, Geoscience Australia, Canberra

GTL Resources 2001, ‘Fischer Tropsch’, Yarm, United Kingdom (www.gtl resources.com/projects-fischer-fischer.htm).

Gorgon Australian LNG (2004), website, various pages, Perth (www.gorgon.com.au).

Haine, I. and commodity analysts 2004, *Minerals and Energy: Major Development Projects,* ABARE, Canberra, April.

Hertel, T. (ed) 1997, *Global Trade Analysis: Modeling and Applications*, Cambridge University Press, Massachusetts.

Hester, S., Tulpulé, V. and Burns, K. 2004, *Japan's Energy Future: Economic Imperatives and Environmental Challenges*, ABARE *e*Report 04.9, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, July.

Hill, C. 1998, What makes a natural gas to liquids fuel project viable?, Paper presented at the Middle East Petroleum and Gas Conference, Dubai, 15–17 March (www.sasolchevron.com/dwn/natural.pdf).

Howard, T. 2004, 'Growing LNG trade accelerating integration of global gas markets', *Oil & Gas Journal Online*, 15 March.

Hubbard, R.G. 2003, Economic growth and reforms in the United States and Japan, Paper presented at the Nikkei/Japan Center for Economic Research Commemorative Symposium, Tokyo, 8 December.

IEA (International Energy Agency) 2002, *World Energy Outlook 2002*¸ OECD, Paris.

—— 2003a, *Natural Gas Information 2003*, OECD, Paris.

—— 2003b, *World Energy Investment Outlook 2003*, OECD, Paris.

—— 2003c, *Energy Policies of IEA Countries — Japan — 2003 Review*, OECD, Paris.

—— 2004a, *Energy Balances of OECD Countries*, OECD, Paris.

—— 2004b, *Energy Balances of Non-OECD Countries*, OECD, Paris.

—— 2004c, *Energy Prices and Taxes 1Q2004*, OECD, Paris.

IMF (International Monetary Fund) 2004, *World Economic Outlook: Advancing Structural Reforms*, Washington DC, April.

Japan Customs 2004, Trade statistics, Tokyo (www.customs.go.jp).

JCER (Japan Center for Economic Research) 2004, *JCER Estimate: Real GDP Rises 1.7% in April*, JCER Report, Tokyo, 2 June.

KEEI (Korea Energy Economics Institute) 2003, *Energy Info. Korea*, Seoul, November.

—— 2004, 'Korea joins gas-producing nations', *Energy Review Monthly*, Seoul, July.

KNSO (Korea National Statistical Office) 2003, *Statistical Data Base* (KOSIS), Seoul (www.nso.go.kr/eng/index.shtml).

KOGAS (Korea Gas Corporation) 2003, *Gas Facts*, Seoul, April.

KPX (Korea Power Exchange) 2002, *The 1st Basic Plan of Long Term Electricity Supply and Demand 2002–2015*, Seoul, August.

L'Hegaret, G., Silvertovs, B., Neumann, A. and C. Hirschhausen 2003, *International Market Integration for Natural Gas? A Cointegration Analysis of Prices in Europe, North America and Japan*, German Institute for Economic Research, Discussion paper 393, Berlin, December.

Lund, P. 2003, Capacity of current infrastructure for supplies of natural gas, Presentation to a joint workshop by the California Public Utilities Commission and the California Energy Commission, San Francisco, 9–10 December.

MacAvoy, P.W. 2000, *The Natural Gas Market: Sixty Years of Regulation and Deregulation*, Yale University Press, New Haven, Connecticut.

MED (Ministry of Economic Development) 2003, *New Zealand Energy Outlook to 2025*, Wellington, October.

Methanol Australia Limited 2004, 'Tassie Shoal LNG project receives environmental approval', ASX Release, Melbourne, 7 May (www.methanol.com.au).

MOCIE (Ministry of Commerce, Industry and Energy) 2002, *The 1st Basic Plan of Long-Term Electricity Supply and Demand*, Seoul, August

—— 2004, *Energy Policies of Korea*, Seoul, January (www.mocie.go.kr/eng).

Neil, C. 2004a, '2003 shows spot cargoes, tankers to dictate US LNG supplies, not terminal capacities', *Oil & Gas Journal Online*, 12 April.

—— 2004b, 'Here's why current imports are limited, how they will grow', *Oil & Gas Journal Online*, 19 April.

OECD (Organisation for Economic Cooperation and Development) 2003, *Economic Survey of New Zealand, 2003*, Policy Brief, Paris, December (www.oecd.org/publications/Pol_brief).

—— 2004, *OECD Economic Surveys 2003-2004: Japan*, vol. 2003/18, Paris, February.

OGJ (Oil & Gas Journal) 2003, 'Worldwide look at reserves and production', *Oil & Gas Journal*, vol. 101, no. 49, 22 December, pp. 46–7.

—— 2004, 'Crystal Energy, AGPA sign MOU for Alaska LNG supply', *Oil & Gas Journal Online*, 3 February.

Penm, J. 2004, 'Economic overview: prospects for world economic growth — affected by high oil prices', *Australian Commodities*, vol. 11, no. 3, September quarter, pp. 377–87.

—— and Fisher, B.S. 2004, 'Economic overview: prospects for world economic growth in 2004', *Australian Commodities*, vol. 11, no. 1, March quarter, pp. 5–20.

Petroleum Economist 2003, *LNG Goldmine CD-Rom*, London.

Petroleum Unit, Brunei Darussalam 2003, Gas industry development in Brunei Darussalam, Paper presented at the Global LNG Summit, Washington DC, 17–18 December.

Platts 2003a, 'Asian LNG prospects', *Power in Asia*, no. 374, 20 March, pp. 5–8.

—— 2003b, 'From Russia with gas – or without', *International Gas Report,* no. 475, 23 May, pp. 9–13.

—— 2003c, 'CPC wants interest in Qatar LNG project: comes after Taiwan firms wins big utility supply tender', *Platts Oilgram News*, vol. 81, no. 129, 8 July.

—— 2003d, 'Crunch looms for India on LNG prices', *International Gas Report*, no. 488/489, 5 December, pp. 1–3.

—— 2003e, 'Indian gas pricing hits the buffers', *Power in Asia*, no. 387, 2 October, pp. 4–7.

—— 2003f, ‘New Zealand eyes LNG option’, *Power in Asia*, no. 389, 30 October, p. 9.

—— 2003g, ‘Qatar inks $17 bn GTL and LNG deals with majors’, *International Gas Report*, no. 485, 24 October, pp. 1–4.

—— 2003h, ‘Gas high on Russia-US agenda’, *International Gas Report,* no. 483, 26 September, pp. 14–16.

—— 2003i, ‘LNG imports probe under way’, *International Gas Report*, no. 484, 10 October, p. 25.

—— 2003j, ‘First Russian LNG project lifts off with Japan deals’, *International Gas Report*, no. 475, 23 May, pp. 1–3.

—— 2003k, ‘Sakhalin-2 scores new Japan deal’, *International Gas Report,* no. 480, 1 August, pp. 14–15.

—— 2004a, ‘Indian LNG debut launches new era’, *International Gas Report,* no. 493, 13 February, pp. 1–3, 36.

—— 2004b, ‘Petronet backs off Kerala Plan’, *International Gas Report*, no. 496, 26 March, p. 24.

—— 2004c, ‘Indian private power projects advance’, *Power in Asia*, no. 400, 1 April, p. 5.

—— 2004d, ‘CNOOC inks Zhejiang LNG pact’, *Power in Asia*, no. 399, 18 March.

—— 2004e, ‘LNG projects proliferate’, *Power in Asia*, no. 400, 1 April.

—— 2004f, ‘CNOOC signs Fujian LNG deals’, *International Gas Report*, no. 508, 24 September, p. 18.

—— 2004g, ‘PLN plans LNG terminal’, *International Gas Report*, no. 491, 16 January, p. 22.

—— 2004h, ‘News in brief’, *International Gas Report*, no. 500, 21 May, p. 35.

—— 2004i, ‘News in brief’, *International Gas Report*, no. 490, 2 January, p. 37.

—— 2004j, ‘Gazprom eyes US/Canada for LNG, *International Gas Report*, no. 494, 27 February, p. 30.

—— 2004k, ‘Singapore to launch LNG study’, *International Gas Report*, no. 493, 13 February, pp. 23–24.

—— 2004l, ‘Power cut spurs LNG probe’, *International Gas Report*, no. 504, 16 July, pp. 18–19.

—— 2004m, ‘Thais sharpen focus on LNG future’, *International Gas Report*, no. 498, 23 April, p. 8.

—— 2004n, ‘Iran/Thai pact covers LNG’, *International Gas Report*, no. 492, 30 January, p. 20.

—— 2004o, ‘Yemen chases Korean deal’, *International Gas Report*, no. 508, 24 September, p. 17.

—— 2004p, ‘Peru eyes US Gulf for LNG’, *International Gas Report*, no. 500, 21 May, p. 29.

—— 2004q, ‘Peru hails Bolivia gas choice’, *International Gas Report*, no. 498, 23 April, pp. 26–7.

Qatargas 2004, ‘Qatargas signs a 20-year deal with Gas Natural’, Media release, 20 January (www.qatargas.com.qa).

Reuters 2003, ‘Update 2 – Korea, China, Russia to discuss $11 billion gas project, *Reuters News*, 21 July, pp. 15–20.

Rigby, P. 2003, ‘LNG: seeking a US market’, in Petroleum Economist, *Fundamental of the World Gas Industry 2003*, Official publication of the 22nd World Gas Conference, Tokyo, 1–5 June, pp. 78–82.

Roberts, P., Cull, A. and Day, J. 2003, ‘Building the Trans-ASEAN gas pipeline’, *Asia Pacific Review*, Jones Day, Hong Kong, July.

Rojey, A. and Chabrelie, M.F. 2003, ‘LNG export projects: steps towards unit-cost reduction’, in Petroleum Economist, *Fundamental of the World Gas Industry 2003*, Official publication of the 22nd World Gas Conference, Tokyo, 1–5 June, pp. 73–76.

Sakhalin Energy 2003, ‘Sakhalin Energy’s multibillion Sakhalin-II phase 2 project becomes official’, Media release, Yuzhno–Sakhalinsk, Russian Federation, 15 May.

—— 2004, ‘Sakhalin Energy signs its fourth LNG supply deal with Toho Gas’, Media release, 12 March.

Schneider, K., Ye Qiang, Curtotti, R., Ball, A., Liu Xiaoli, Wu Zhonghu, Gao Shixian, Jiang Xinmin and Su Zhengming 2003, *Natural Gas in Eastern China: the Role of LNG*, ABARE Research Report 03.1, Canberra.

Shell 2004a, ‘Hazira port & terminal’, New Delhi, (www.shell.com).

—— 2004b, ‘Shell gives green light for Pohokura Development’, Media release, Wellington, 30 June.

—— 2004c, ‘Larger LNG plants, 5 to 8 Mtpa’ (www.shellglobalsolutions.com/gasevents/lng/Larger_LNG_Plants,_5_to_8_mtpa.pdf).

—— 2004d, ‘Qatar Shell GTL project’, Doha (www.shell.com).

—— 2004e, ‘Sakhalin Energy signs pioneering LNG supply deal with Shell for north American markets, Media release, Moscow, 14 October.

Singleton, A. and Cooper, P. 1997, *Conversion of Associated Natural Gas to Liquid Hydrocarbons*, Report to US Department of Energy’s Federal Energy Technology Center, Pittsburgh (www.netl.doe.gov/publications/proceedings/97/97ng/ng97_pdf/NGP15.PDF)

Suzuki, T. and Morikawa, T. 2003, *Natural Gas Demand Supply Trends in the Asia Pacific Region*, Institute of Energy Economics Japan, Tokyo, October (eneken.ieej.or.jp/en/data/pdf/210.pdf).

Taylor Sen, C. 2003a, ‘LNG poised to consolidate its place in global gas trade’, *Oil & Gas Journal Online*, 23 June.

—— 2003b, ‘New supply projects to push LNG into major markets’, *Oil & Gas Journal Online*, 30 June.

Vallee, J. 2003, ‘FERC hackberry decision will spur more US LNG terminal development’, *Oil & Gas Journal Online*, 10 November.

Woodside 2003, Australian gas: commitment to growth, Presentation at Investor Briefing Day, Perth, 19 November (www.newsite.woodside.com.au).

WMRC (World Markets Research Centre Limited) 2004, 'TNK-BP promotes Kovykta as cornerstone of Russia's east Siberia gas development plans', *WMRC Daily Analysis*, London, 20 April.

Wybrew-Bond, I. and Stern, J. (ed.) 2002, *Natural Gas in Asia: the Challenges of Growth in China, India, Japan and Korea*, Oxford University Press, England.

Xu Dingming 2002, *China's Natural Gas Industry in Development*, Department of Industrial Development, State Economic Trade Commission, Beijing, February.

Yamaguchi, K. and Cho, K. 2003, *Natural Gas in China*, Institute of Energy Economics Japan, Tokyo, August (eneken.ieej.or.jp/en/data/pdf/221.pdf).