Asia-Pacific gas market growth

June 2009

Asia-Pacific Partnership on Clean Development & Climate

PricewaterhouseCoopers

Acknowledgement

Australian Government

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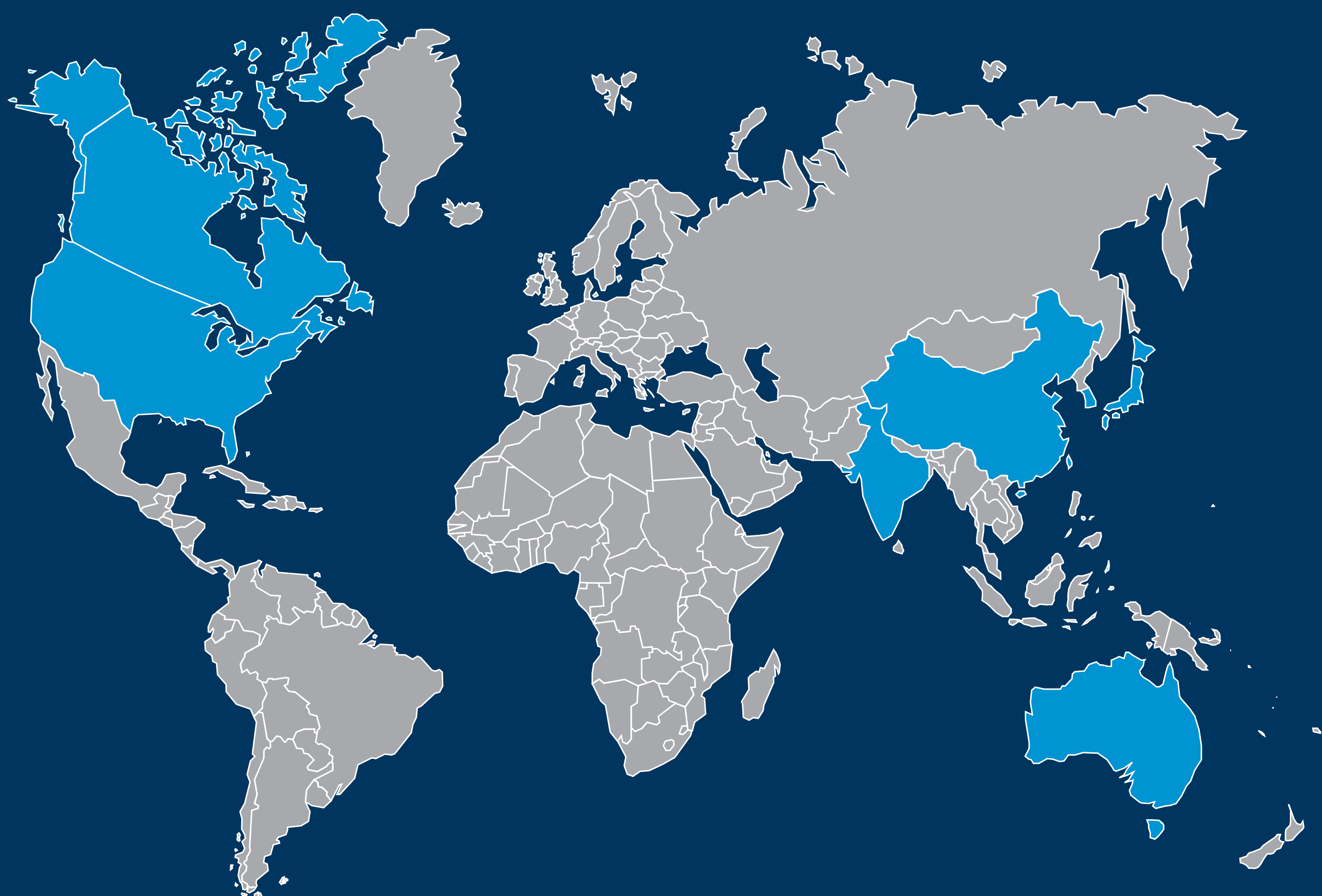


Introduction

The Asia-Pacific Partnership on Clean Development and Climate (the APP) is an innovative effort to accelerate the development and deployment of clean energy technologies. The seven members of the partnership – Australia, Canada, China, India, Japan, Republic of Korea, and the US (the APP Partner economies) have agreed to work together and with private sector partners to meet common goals.

The APP Partners have approved eight public-private sector task forces. One of these, the Cleaner Fossil Energy Task Force, has in turn developed an Action Plan that includes an initiative referred to as the *Asia-Pacific Gas Market Growth Project* (CFE-06-08). Overall objectives of the Gas Market Growth Project are consistent with those of the Asia-Pacific Partnership – that is to promote energy security, reduction in national air pollution and climate change in ways that promote sustainable economic growth and poverty reduction.

The Australian Petroleum Production & Exploration Association (APPEA) is the leader of the project under the auspices of the APP and has engaged PricewaterhouseCoopers to assist the project with a study of the APP gas markets, and to prepare a report. The study called for a staged approach consisting of initial research, data collection and analysis, modelling, stakeholder consultations and interpretation of individual country and collective APP outcomes.

Key findings and conclusions

Gas exporting and large consuming countries have a mutual interest to develop markets for natural gas to ensure greater efficiency of gas transport, trade and consumption. The key messages that come through as a result of the qualitative and quantitative assessment of each country, and collectively as the APP group of countries, are:

- There are substantial opportunities to grow gas use in the APP economies. Opportunities are greatest in the electricity generation sector, particularly in countries that have low gas penetration, increasing power requirements and pending environmental constraints.
- Growth of gas in a country's energy mix will have a positive impact on energy security, greenhouse gas emissions and air pollution.
- Governments in importing countries can assist the supply side by improving their respective domestic gas markets by providing greater levels of energy policy and regulatory certainty to encourage large-scale projects to move forward.
- Domestic gas market growth should be underpinned by government policies and regulation that support market development and provide an environment of certainty. Key focus areas for energy policies are to provide clarity around the cost of carbon emissions and to clearly articulate the preferred energy mix for the respective countries.
- There are significant differences between the efficiency of gas markets in the Atlantic Basin and the Asia-Pacific with a lower level of market efficiency in many Asia-Pacific countries.

Challenges facing the market for natural gas and LNG

There are two significant challenges faced by the LNG and the broader gas industry.

The first relates to the complexity and risks of large-scale projects, such as LNG projects, and the need for, and ability to provide, security of supply to countries and their large consumers. This represents a convergence of global supply issues and direct/indirect impacts on each of the importing countries.

The second is the need for certainty and commitment to gas market development in the importing countries. Their governments can help reduce this risk by improving domestic gas markets to a point where stable and predictable government policies, regulation and end-user demand provide certainty for investors rather than adding to investor risk.

Both issues are addressed in the report, with particular focus on the domestic gas markets in the APP countries.

Report structure and key issues

The gas supply chain and regulatory environment – Overview by country

This report provides an overview and analysis of the gas market in each of the seven APP Partner economies. For each country the report describes the gas supply chain and the regulatory and legislative environment. The report also discusses ways to address the most significant impediments to gas market growth.

The key issues are aggregated so that potential improvements can be collectively considered for the APP Partner economies. The key impediments to gas market growth fall into two broad categories:

- Global policy issues, mainly as they relate to climate change and energy mix. All policies implemented by governments to reduce carbon emissions, whether stated or implicit, will affect the relative cost of all fuels, including energy from coal, gas, nuclear or renewable sources.
- Regional and country specific issues, mainly in relation to the policy and regulatory approach to competition, infrastructure and pricing. These issues will reflect that markets are at different stages of development.

Gas market and economic modelling

A gas market and economy-wide model was established for each of the APP economies. The intent of these models were to establish a base case and "scenario-test" it against the impact of factors such as climate change policy to assess the impact on use of gas and gas infrastructure development. These results were then fed into an economy wide model to then assess the subsequent impact on economic growth.[1] Results in aggregate for all of the APP Partner economies show that:

- The base case forecast, without a carbon signal, is a declining share for gas in total primary energy supply, from 15% in 2008 to 13% in 2025 across the APP Partner economies. This mainly reflects energy growth in China and India, and a forecast decline in the share of gas in the US energy mix towards the end of the modelling period.
- There is significant scope for increasing gas use in the APP, particularly in the countries that have low gas penetration at present. A modelling scenario that includes a carbon signal indicates a gas demand increase from 15% to 19% of the total primary energy supply.
- The electricity sector is the most important sector for growth in the medium to long term. Gas's share of electricity generation output in the scenario will grow from 11% at present to 19% in 2025. This mainly represents a fuel switch from coal to gas.
- Switching investments from coal to gas has a favourable impact on the key indicators for energy security, which is displayed by an increase in a measure of 'Diversification of primary energy demand'.
- Increased use of gas has a favourable impact on CO2 emissions and air pollution. The scenario shows a 7% reduction of CO2 emissions compared to the base case, and a 15% reduction in air pollution (measured as nitrogen oxides, sulphur dioxide and particulates).
- The scenario suggests a modest negative impact on economic growth and aggregate consumption to the end of the modelling period in 2025, mainly caused by higher cost of energy. However, it also can be argued that the long term economic impact is positive, provided that the higher energy cost is consistent with a market based value of carbon that fully reflects the impact of global warming.

Impediments to growth – The way forward

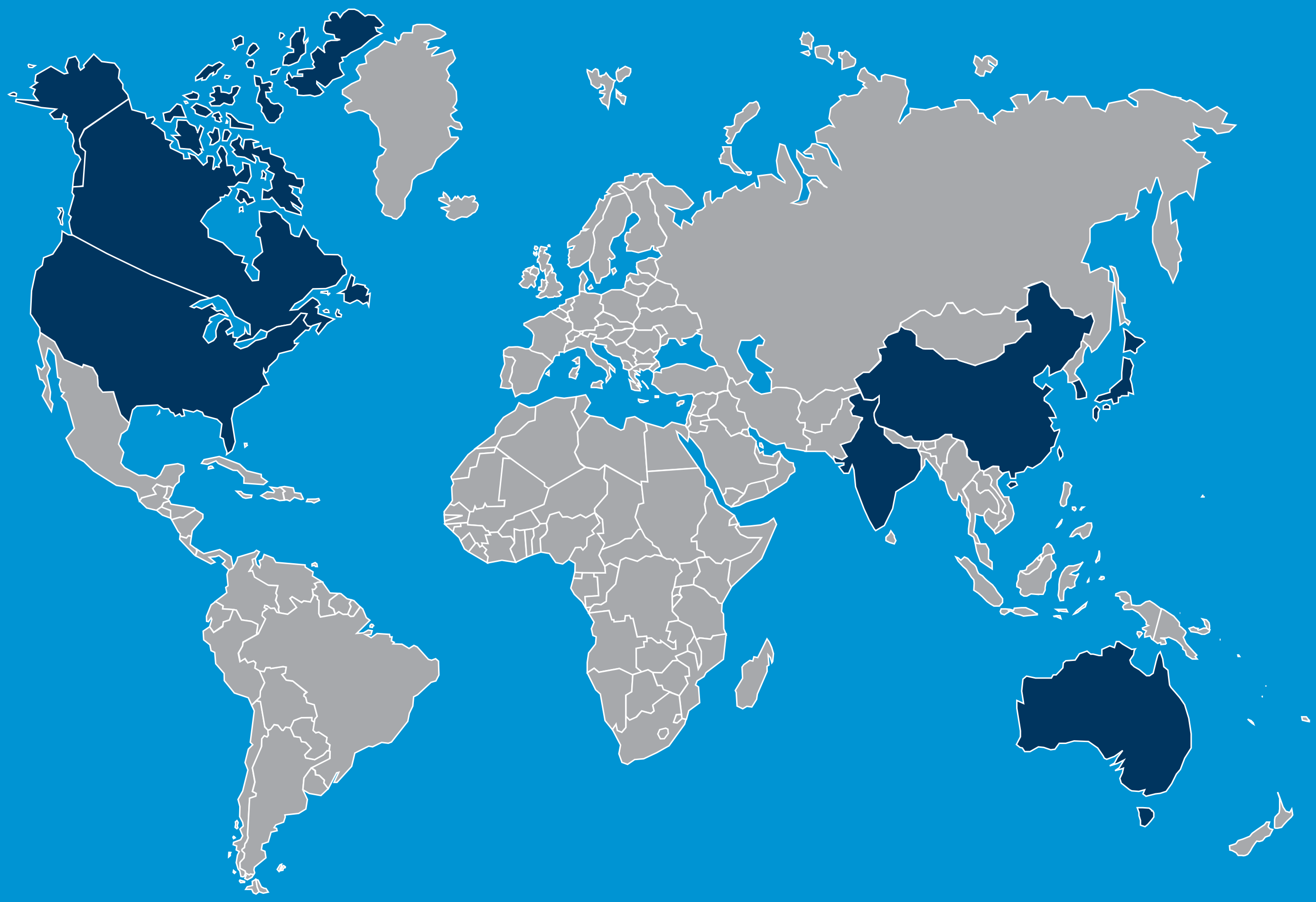
This report is now distributed to the APP partners for review as they determine how best to implement plans to increase the efficient use of gas across regions and countries.

It is evident that the current financial crisis will receive considerable attention at this point in time. Economic developments will clearly have some impact on greenhouse gas emissions initiatives and the ability to develop natural gas and LNG projects that require large capital investment. However, the nature of the findings in this report take a medium to long term view and the results will retain their relevance for some time to come.

[1] Modelling of 'business-as-usual' is referred to as the 'base case'. The 'scenario' quantifies the impact of removing some of the barriers.

PART A Introduction and gas market overview

Australia • Canada • China • India • Japan • Korea • US



1 The Asia-Pacific gas market growth project

1.1 Project background

The Asia-Pacific Partnership on Clean Development and Climate (the APP) is an innovative effort to accelerate the development and deployment of clean energy technologies. The seven members of the partnership – Australia, Canada, China, India, Japan, Republic of Korea, and the United States (also referred to in this document as the APP Partners or the APP7) – have agreed to work together and with private sector partners to meet common goals.

The APP Partners have approved eight public-private sector task forces. One of these, the Cleaner Fossil Energy Task Force, has in turn developed an Action Plan that includes an initiative referred to as the Asia-Pacific Gas Market Growth Project (CFE-06-08).[2] The Australian Petroleum Production & Exploration Association (APPEA) is the leader of the project under the auspices of the APP and has engaged PricewaterhouseCoopers to assist the project with a study of the APP gas markets, and to prepare a report.

1.2 Objectives and approach

Objectives

Overall objectives of the Gas Market Growth Project are consistent with those of the Asia-Pacific Partnership – that is to promote energy security, reduction in national air pollution and climate change in ways that promote sustainable economic growth and poverty reduction.

Specifically, this project's objective is to achieve a gas market in the APP Partner economies that is consistent with the APEC Energy Working Group's (potentially expanded and amended) best practice principles[3] to facilitate the development of natural gas markets, LNG trade and market access in the region. In doing so, an increase in the share of energy consumption supplied by gas, is expected.

Approach

The project will analyse the Asia-Pacific region gas market conditions, identify impediments to and provide solutions for improving market conditions. The extensive requirements of the project necessitated a staged approach consisting of initial research, data collection and analysis, modelling, stakeholder consultations and interpretation of individual country and collective APP outcomes.

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2 www.asiapacificpartnership.org/FossilEnergyTF.htm

3 Appendices: Regulatory Best Practice Principles

Data and measurement

Information and data used for figures in the report and for modelling of the APP energy markets have been obtained from a range of sources as summarised in Appendix C. Other information and data used in this report are referenced as used.

Data, modelling assumptions and analysis reflect market conditions during 2008, up to the time of issuing the draft report in November 2008. More recent statistics are continuously becoming available, so this report should not be regarded as an up-to-date library for energy resources and consumption. The quoted figures are intended to be consistent with the sources used for modelling, and alternative data sources have been quoted when practical.

Energy is quantified and referred to in a variety of units, depending on the commodity, location and purpose of measurement. Figure 1.1 provides approximate conversion factors between the most frequently used measurement units for natural gas and LNG.[4] We have attempted to use a common unit of measure through the report except in instances of direct quotes from information sources.

Figure 1.1 Measurement units for natural gas and LNG

Column A	Bcm	Bcf	Tcf	Mt of LNG	PJ
1 billion cubic metres of natural gas (Bcm)	1	35.3	0.353	0.73	38.0
1 billion cubic feet of natural gas (Bcf)	0.028	1	0.001	0.021	1.086
1 trillion cubic feet of natural gas (Tcf)	28	1,000	1	21	1,086
1 million tonnes of LNG (Mt)	1.38	48.7	0.487	1	54.9
1 Petajoule (PJ)	0.026	0.92	0.00092	0.018	1

Additional Information

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[4] Energy values derived from BP Statistical Review of World Energy, 2008. (1 BCM = 36 trillion BTU and 1 KJ = 0.948 BTU).

2 Markets for natural gas and LNG

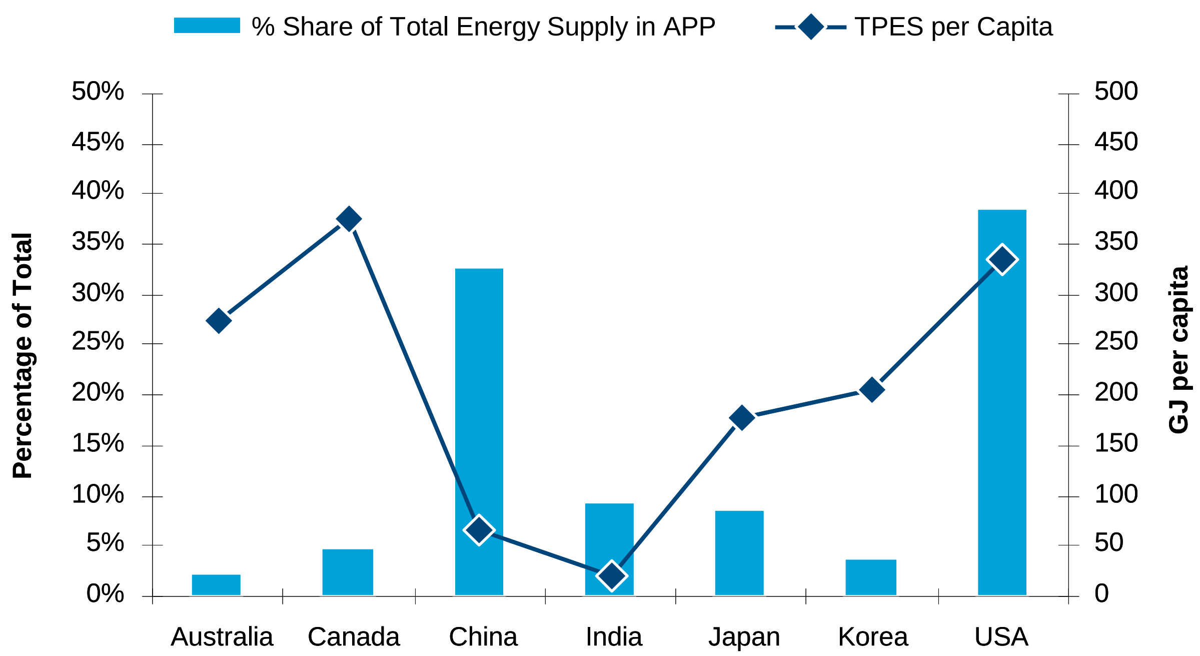
2.1 Snapshot of the APP 7 energy markets

2.1.1 Energy supply and energy consumption

The APP Partners' energy markets are vastly different, whether one is measuring availability of domestic resources, level of energy consumption, or reliance on specific types of fuel. For example, Australia and Canada are sparsely populated countries with high national income and an abundance of natural resources. At the other end of the spectrum are the developing countries of India and China which are densely populated with more than a billion people each, and the densely populated Korea and Japan which import virtually all their energy requirements.

Figure 2.1, which is based on data for total primary energy supply in each Partner economy, shows that China and the US are the dominant energy users, and these two countries combined represent 82% of the total energy consumed within the APP.

Figure 2.1 Energy consumption by country

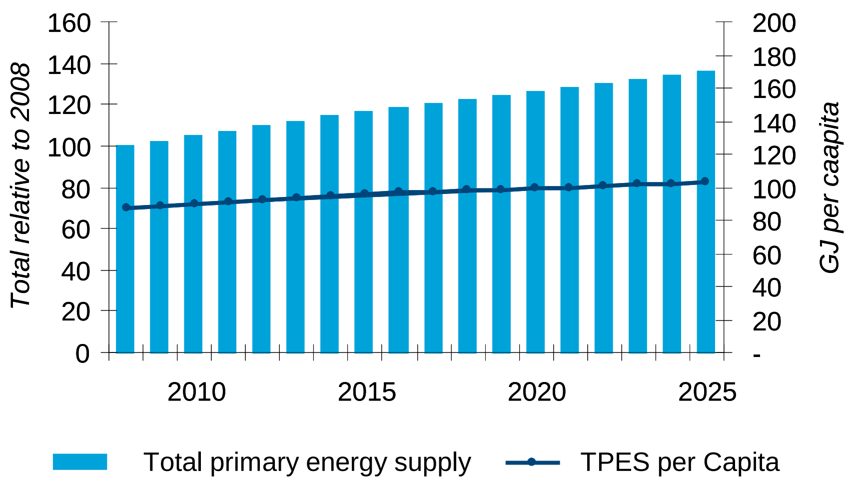


The importance of APP Partner economies in terms of energy supply in a global context is illustrated by the fact that six of the seven members are amongst the top ten energy users in the world. The US is the world's largest energy user with an estimated consumption of 21% of the world's total, but China may take over this position in about 2012 if current growth rates continue over the next several years. Russia is a distant third with 6% of the world's total energy consumption.

Within the APP Partner economies the average annual energy use per person is 88 GJ, but the differences are substantial. Consumption in Australia, Canada and the US is three or four times greater than the APP average. India's usage per capita represents only one-quarter of the APP average.

Figure 2.2 shows that energy consumption in the APP economies is forecast to grow by 35% to the year 2025 and that energy consumption per person will increase from 88 GJ per capita to 103 GJ per capita.

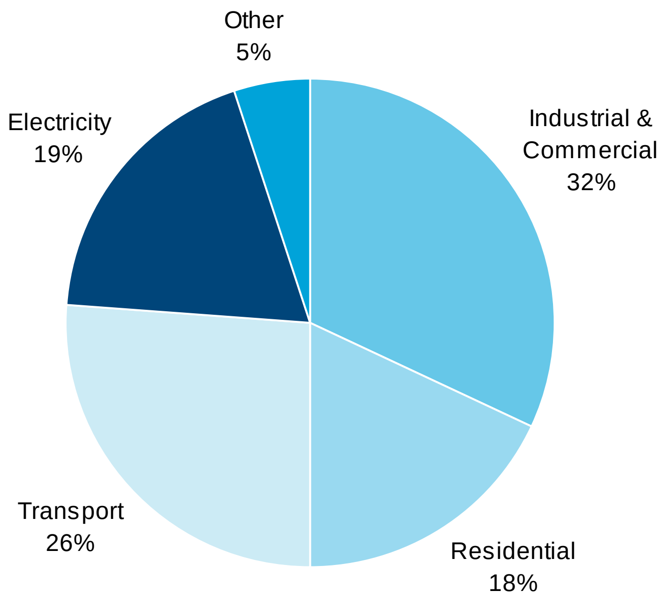
Figure 2.2 Forecast increase in energy consumption



Per capita measures are most frequently used when comparing the status of different economies, for example in relation to economic development and creation of wealth. Generally speaking, a developed country with high gross domestic product per capita will also have high energy consumption per capita. Per capita measures have also been used in this report to show comparative numbers for the respective APP countries' level of greenhouse gas emissions and pollution.

Key energy statistics

Figure 2.3 Energy use by sector



Energy use across the industrial, residential, transport and electricity sectors is displayed in Figure 2.3.

There are substantial differences in the way energy consumption is split between sectors in the APP Partner economies. For example, the residential sector represents a significantly higher share of energy consumption in China and India than in the other countries.

The electricity sector represents approximately 19% of total energy usage at present, and this percentage is expected to grow to 24% as new capacity is installed.

Total electricity generation capacity in the APP is forecast to grow from 2,368 GW in 2008 to 3,644 GW in 2025, representing growth of over 54%. The main contributors to this increase are China (66%), India (21%) and the US (10%). Australia's capacity increase is also significant in relative terms. In addition to capacity growth in all countries except Japan, new plants are also required to replace older generation plants that are due to be retired over the forecast period.

Figure 2.4 Primary fuel sources and electricity capacity by country[5]

	Main fuel in energy mix	Second fuel in energy mix	Gas % share of total	Nuclear	Electricity capacity (GW)	
					2008	2025
APP 7	Coal (37%)	Oil (32%)	15%	Yes (6%)	2,368	3,614
Australia	Coal	Oil	18%	-	49	77
Canada	Oil	Gas	28%	Yes	117	139
China	Coal	Oil	3%	Minor	699	1,544
India	Coal	Biomass	6%	Minor	174	436
Japan	Oil	Coal	15%	Yes	278	246
Korea	Oil	Coal	17%	Yes	73	92
USA	Oil	Gas	24%	Yes	980	1,080

Breakdown by APP Partner

Figure 2.4 shows that coal and oil combined represent more than two-thirds of the total primary energy supply in the APP economies.

- Coal represents 37% of energy supply and is mainly used in the industrial and electricity sectors.
- Oil, with 32% penetration, is the second most used fuel overall and the dominant fuel in the transport sector.
- Substantial quantities of both coal and oil are also used for space heating within the residential sector in China.

Gas is a distant third in the energy mix and represents 15% of total primary energy supply. Gas penetration is highest in North America (24-28%) and lowest in China and India (3 - 6%).By comparison, gas represents about one-quarter of energy demand in the European Union and more than half of energy demand in Russia. Hence there are opportunities to grow the APP gas markets on a comparative basis, particularly in the countries with the lowest usage of gas.

5 Data as per the modelling in Part C. Gas' share of the total is based on Total Primary Energy Supply as defined in the modelling. Variances from alternative sources may be due to definitions and the interpretation of available data.

Biomass and waste is the second most important fuel in India and the third most important fuel in China, mainly because rural households in these countries depend on it for most of their cooking needs. Biomass and waste is also used for residential space heating in China.

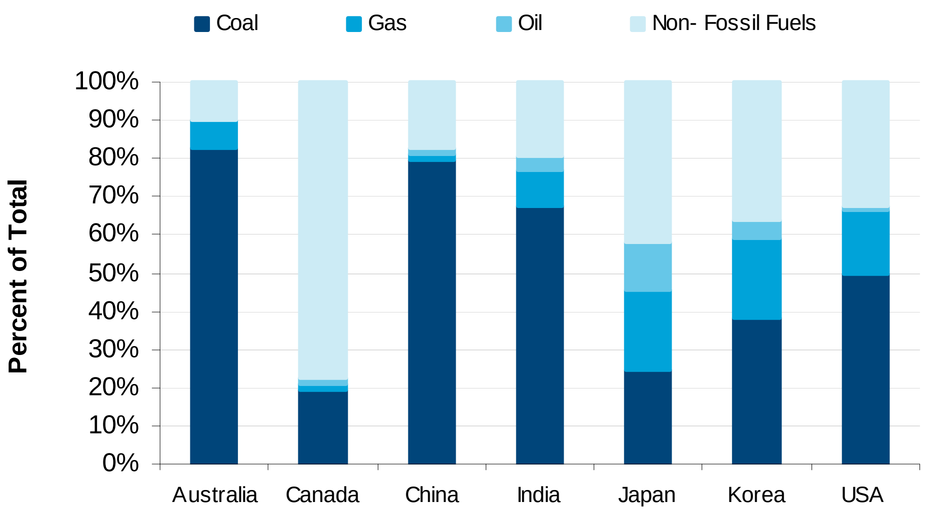
Six of the seven APP Partners use nuclear electricity, although this represents only about 1% of the energy supply in China and India.

Figure 2.4 also provides an idea of the APP 7's total current and forecast electricity generation capacity. The electricity sector is very important for gas market growth in the short to medium term as 'combined cycle' (efficient base load) gas plants are well placed to cater for new electricity demand and the replacement of old coal-fired plants. Once the investment is made, electricity generation plants have an expected life of 25 to 40 years. History shows that the life span is often extended through upgrades and replacement of major components and equipment.

The benefit of increased gas penetration in the other sectors is equal to or even greater than in the electricity generation (when energy efficiency is taken into account), but these initiatives may take longer to implement due to the time involved in changing people's consumption patterns, and reliance on investments in infrastructure or technology.

Figure 2.5 illustrates fuel usage for power generation and illustrates that three countries (Australia, China and India) are extremely reliant on coal for power generation.

Figure 2.5 Power generation by type of fuel



The penetration of gas for power generation compared to other fuels sources is low in all countries. Of note, the two countries with virtually no domestic gas supply (Japan and Korea) have the highest penetration of gas in this sector.

The proportion of non-fossil fuels is greater than 30% in four of the seven countries. Canada stands out because of its high share of hydro power. Japan, Korea and the US also have a substantial supply of electricity from nuclear plants.

The share of power generation from renewable energy (other than hydro) for power generation is low in all countries.

2.1.2 Availability and trade of gas

Despite holding only a small percentage of the world's total gas reserves, the APP Partners have a high share of the global consumption and trade in natural gas and LNG. Figure 2.6 and Figure 2.7 display the APP Partner economies' reserves and production relative to other regions.

Figure 2.6 Proved reserves at the end of 2007[6]

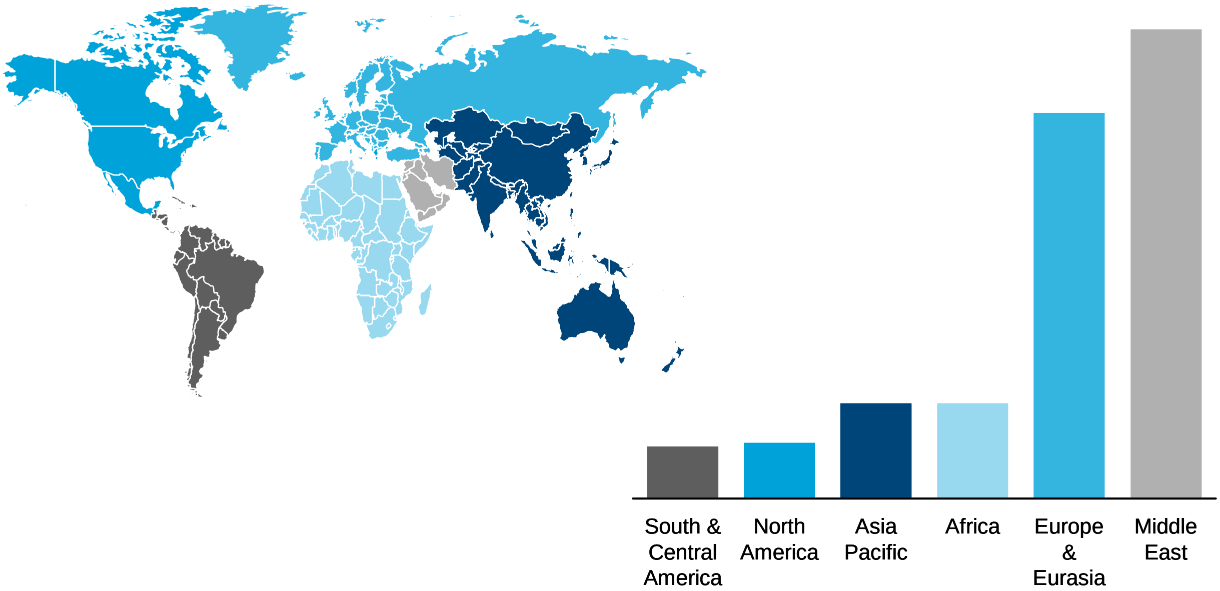


Figure 2.7 APP7 gas production and consumption comparison

Bcf (Billion cubic feet)	World	APP7	Percentage
Gas proved reserves	6,263,340	461,073	7%
Production	103,782	30,677	30%
Consumption	103,143	35,537	35%
Piped gas trade	19,403	4,310	22%
LNG imports (Gross)	7,992	5,605	70%
LNG exports (Gross)	7,992	756	10%

The above figures can be summarised as follows:

The Middle East holds 41% of the world's gas reserves, of which Iran and Qatar each have approximately 15%. Saudi Arabia and the UAE also have significant reserves.

The high reserves in Europe and Eurasia are mainly located in the Russian Federation which has 25% of the proved world reserves of gas. Norway and Turkmenistan also have significant gas reserves, and the African reserves are mainly located in Nigeria and Algeria.

6 BP Statistical Review of World Energy 2008. (Piped gas trade excludes trade within the former Soviet Union).

The APP Partner economies have only 7% of the world reserves, of which about half is estimated to be in the US. This is in contrast to the APP Partners' share of consumption, where they represent about one-third of the world's total.

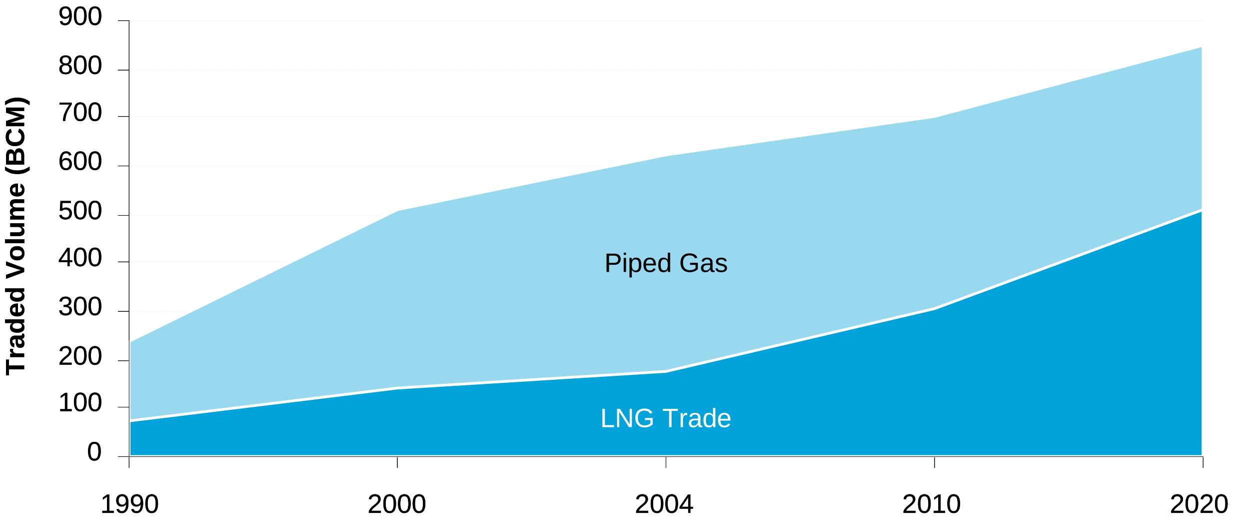
More than two-thirds of the global LNG trade involves the seven APP Partner economies. The two largest LNG importers in the world are Japan and Korea, with the US, India and China also importing significant volumes of LNG. Australia is the only net LNG exporter among the APP Partners. Piped gas trade in the APP only occurs between the US and Canada.

2.2 Overview of LNG markets

2.2.1 Imports and exports

LNG is one of the fastest growing sectors of the energy market. Traded volumes will grow strongly to 2010 as Qatar is expected to commission four new LNG production trains in the next two years. Projections from Cedigaz suggest a further 65% increase in LNG trade from 2010 to 2020. Figure 2.8 indicates that LNG will overtake piped gas in terms of cross border trade by 2020.

Figure 2.8 Traded volumes of LNG and piped gas



As at the end of 2007 the global LNG market consisted of a small group of 15 exporting and 17 importing countries. The main LNG suppliers are national oil companies, and major oil companies such as Shell, BP and ExxonMobil.

Figure 2.9 Major players in the LNG market

Main LNG importers in 2007			Main LNG exporters in 2007			Countries expected to increase export capacity by 2015
1	Japan	39%	1	Qatar	17%	Qatar
2	Korea	15%	2	Malaysia	13%	Nigeria
3	Spain	11%	3	Indonesia	12%	Australia
4	USA	10%	4	Algeria	11%	Egypt
5	France	6%	5	Nigeria	9%	Iran
7	India		6	Australia		Russia
9	China		12	USA (Alaska)		Yemen

Figure 2.9 clearly illustrates that the APP Partners play a dominant role on the importing side of the global LNG trade. The limited presence of Russia and Iran in the LNG trade does not reflect their large gas reserves; however this situation may be about to change as Europe prepares to increase imports in order to replace falling production in the UK.

The global LNG market is not classified as its own commodity market, and liquidity and transparency of the LNG market may not improve dramatically in the short term. A key reason is that the LNG market has relatively few players when compared to traditional commodity markets for oil, metals and agricultural products. The transaction size of any commodity cargo is also quite large and difficult to split into smaller parcels. In addition, because of the large and long-term nature of activities that involve LNG, most notably financial and contractual commitments, buyers and sellers do not necessarily behave in a way that is consistent with the development of a liquid and transparent commodity market. These issues are discussed below. Lastly, LNG contract pricing seeks price referencing from the crude oil markets opposed to price referencing of LNG.

2.2.2 Contracts and pricing

Significant contract terms

With respect to the gas supply contracts, buyers and sellers of gas have slightly different priorities:

Figure 2.10 LNG contract terms

	Main priorities for LNG buyers	Main priorities for LNG sellers
1	Energy security. Reliable and uninterruptible supply.	Long term contracts with creditworthy customers (with respect to both country and counterparty).
2	Maximum flexibility, for example in terms of off-take, ability to manage seasonality, cargo size, and ability to on-sell the gas.	Certainty with respect to minimum sales volumes (as reflected in buyers Take-or-Pay commitments).
3	Affordability and price certainty.	Minimum price (floor price).

Clearly, the first priority for both buyers and sellers is security. Buyers will look for reliable sellers and vice versa, and more often than not they will find each other.

From the sellers' point of view, long-term contracts with creditworthy buyers will underpin new projects and hence secure project finance and investment of equity. 'Take-or-Pay' forms an integral part of the project.

Pricing is not on top of the list for either buyers or sellers, provided that the negotiated terms are comparable to similar contracts in the market. Specifically, buyers can often accept industry-wide price increases, or, in a monopoly situation, price increases that can be passed on to customers. Sellers are more inclined to accept price risk than volume risk, and publicly listed companies often claim that their shareholders invest because they want the exposure to commodity prices.

Pricing

The market for LNG is small compared to that for piped gas in the Atlantic Basin and compared to oil in the Asia-Pacific. Hence, LNG has often been a price taker in the past rather than a price setter. Pricing has traditionally been based on similar terms for the destination of LNG cargoes, including the common reference points for the markets in Figure 2.11.

Figure 2.11 Price references for LNG

Destination	Price reference
Japan / Asia	Japanese Crude Cocktail (JCC) or fuel oil
United Kingdom	National balancing point (NBP) in the UK
Europe	Crude oil or fuel oil
North America	Henry Hub price index (also traded on NYMEX)

The Japanese Crude Cocktail has traditionally been the most important price comparison and reference point for the LNG market (due to Japan's large share of the market), and this method of pricing has also established a clear link between the cost of gas and oil. LNG deliveries to the UK and US are priced relative to the domestic reference points for natural gas.

The exact price terms in long-term contracts are confidential, and vary from contract to contract. Terms typically reflect the market power between buyers and sellers at the time of entering into the contract. For example, individual pricing arrangements may include price floors, price caps, or a 'slope' that determines the mathematical link between LNG and oil prices.

2.2.3 The developing global LNG market

New supplier and destination countries have emerged in recent years, and this has brought greater volumes and dynamism to the LNG market. Perhaps most significant is the upsurge in Middle Eastern production as a result of major expansions in Qatar, Egypt and Oman. This has created a supply-side link between the Atlantic Basin and the Asia-Pacific markets.

Qatar has just overtaken Indonesia and Malaysia to become the leader in LNG production. There is still considerable uncertainty about the new capacity (in terms of both timing and the level of contracting), but some market commentators expect that significant Qatari production volumes will be available on spot terms to the highest-priced market.

Recent statistics also support the view that spot trading and short-term contracting for LNG is more common today than just a few years ago. A recent estimate is that short-term trades (defined as two years or less) have increased from 2% in 1997 to 16% of LNG-traded volumes in 2006.[7]

It is highly unlikely that the LNG market will become as transparent and liquid as the established commodity markets for oil, metals and agricultural products. However, the trend is clearly that of becoming more like a global commodity. The rate of increasing imports to the US and UK combined with any spare or uncommitted capacity in the Middle East will be key to shaping the market.

A move in this direction will benefit both buyers and sellers, as it introduces more flexibility and options into a market place that traditionally has been quite rigid in terms of contractual arrangements.

7 East-West Center, 2006

3 Global issues and impediments to growth

3.1 Significant economic developments

The main events of 2007 and 2008 that will have a profound and long-term impact on the global energy markets relate to changes in energy prices, the need to address climate change, and the turmoil in financial markets. We discuss each of these in turn.

Energy prices

Crude oil prices more than doubled from previous levels of $30 / bbl in the year 2000. Prices in late 2008 are well down from the extreme highs above $130 / bbl in the 2nd quarter of 2008, and volatility is still very high as this report is being prepared. Current prices are again comparable to the levels from 2006 and 2007. Natural gas prices have broadly followed this lead.

High energy prices have two effects:

- First: development prospects and investments that were only marginal 5-10 years ago now look very favourable.
- Second: as affordability and fuel substitution becomes a key issue for all the consuming sectors, demand is curtailed.

Climate change

The climate change debate has moved beyond the point of discussing whether global warming is caused by human intervention. The focus in many countries is to quantify the costs, and implement measures to address the problem. Developed countries are expected to make the first moves towards a low-carbon economy.

Initiatives to address climate change are likely to favour gas and non-fossil fuels (nuclear and renewable energy) at the expense of oil and coal. These initiatives may be implemented through a range of options, including indirect taxes on fuel, costs imposed on carbon emissions or direct incentives to build renewable energy generation.

Financial markets

The world is experiencing a major financial crisis as we prepare this report. The extent to which the lack of confidence in the financial markets will affect the long-term outlook for natural gas and LNG remains to be seen, but there are likely to be both positive and negative implications.

In the first instance, all risks related to large-scale projects will be scrutinised as credit-providers seek to minimise their exposures. This may lead to an increase in funding costs, and to further emphasis on requirements to control project expenditure and reduce the variability of cash flows.

The broader implication is that any significant downturn in the economy will contribute to lower energy demand in general. This will in turn reduce greenhouse gas emissions and benefit worldwide efforts to address climate change.

3.2 Barriers to expansion of natural gas and LNG trade

In 2004 the APEC Energy Working Group released a paper that addressed issues in relation to cross-border natural gas trade in the APEC region.[8] The impediments to growth that were raised in this document are still valid, although the context and order of importance may have changed since then.

Figure 3.1 summarises and discusses these global issues in the context of today's gas and LNG markets, taking into account the economic developments discussed above.

Figure 3.1 Barriers to expansion of natural gas and LNG trade

The barrier	What this means in today's market
Securing a market	New LNG projects must secure a market in order to attract investments and finance. In the absence of a liquid commodity market for gas to support the project, large investments are underpinned by long-term contracts with Take-or-Pay.
Energy security	Buyers require certainty of supply, both long term and short term. This refers to the role of gas to support a balanced overall energy mix, as well as the need for uninterrupted gas supply to meet the essential demand from households and industry.
Distance to markets	There are long distances between the main gas resources in the world (Russia, Qatar, and Iran) and the main importers in USA, Central Europe and East Asia. This results in costly transport, complexity in the supply chain, and potential disputes in relation to the use of transit pipelines and import terminals.
Infrastructure	Growth of the natural gas and LNG markets requires substantial infrastructure for production, transport, import facilities, transmission pipelines and distribution systems. This infrastructure represents long-term commitments from investors who expect an acceptable return on their investment.
Environment and safety	Both governments and the public may be concerned with the environmental impact of upstream developments and/or the safety of re-gasification plants, processing plants and import terminals.
Market structure	Some market participants prefer an integrated industry structure (supported by long-term contracts) in order to manage risks. This may in turn reduce market liquidity and the availability of natural gas and LNG on a spot basis.
Cost and financing	The cost of developing natural gas and LNG projects (including transportation infrastructure) has increased substantially in the last five years. The global financial crisis in 2008 (caused by extreme tightening of the credit markets) will also increase costs and complicate the task of securing finance for large projects.
Policies, regulation and pricing	Consistency and transparency between policies, regulations and legal frameworks between the various countries involved can facilitate the growth of cross-border trade. This is particularly the case for immature and developing markets whose policies, regulations and legal frameworks are in nascent stages of development.
Instability of investment conditions	Investors looking for predictable returns value a stable investment climate with fiscal policies that support or encourage risk-taking activities. Potential changes to government policies, regulation, royalties and taxes create uncertainty for investors.

It is important to note that the list of barriers to expanding trade in natural gas and LNG does not include significant trade barriers. Rather, the key message in the table above is that any initiatives and plans to increase the use of natural gas and LNG must address risks and uncertainty on a large scale.

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8 Great Expectations: Cross Border Natural Gas Trade in APEC Economies. APEC Energy Working Group November 2004.

From the point of view of the supply side, it is evident that the broader challenges for major gas and LNG projects extend far beyond the task of developing gas reserves and transporting the gas to end users.

Long lead times and the complexity of developing LNG facilities have been well documented. The cost of large projects is reported to be in excess of $5 billion for 3-4 Mt/annum LNG plants. Capital expenditure for potential projects offshore north-west Australia such as Ichthys and Gorgon is in the order of $15-20 billion. It goes without saying that development cost and construction risks must be well managed and controlled, and it is equally clear that projects of this magnitude will not obtain the necessary support from investors and financial institutions unless the broader risks are also deemed to be acceptable.

These broader risks include uncertainty in relation to the demand side for gas for buyers, including the ability of the purchaser to meet its financial obligations, a demonstrated long term regional commitment to build and maintain gas infrastructure, and sovereign risk which also captures all relevant aspects of government policies, regulation and investment conditions in the respective countries.

Consequently, from the point of view of the demand side, it is most important to determine how importing countries can assist the supply side by reducing or eliminating risks that otherwise will discourage investment in gas and LNG production facilities.

3.3 Challenges facing the LNG industry

The top 10 challenges facing the LNG industry in 2008 were recently presented at an international industry conference in Singapore.[9] These challenges, with our interpretation of what they entail, are summarised in Figure 3.2.

Figure 3.2 Top 10 challenges facing the LNG industry today

The issue	Why is it a challenge?
Supply availability	Supply is tight at present, and most of the LNG production is fully committed under long-term contracts. Other issues that contribute to the shortage of supply include domestic priorities in Indonesia, the delay or cancellation of several new projects, Qatar’s moratorium on new developments, and both international and domestic issues in relation to Iran.
Escalating construction costs	Liquefaction costs have increased the most, but all construction costs are significantly higher now than 5 years ago, in part due to higher commodity prices. Shortages of skilled engineers and labour also contribute to the problem.
Labour shortages	Shortages create challenges throughout the value chain, including technical areas, construction and plant operations.
High prices and volatility	All energy prices have increased in the last 2-3 years. Regional differences are caused by local gas shortages and different pricing mechanisms in contracts.
Geopolitics	Some countries with large gas reserves represent high sovereign risk (Russia, Iran, Nigeria, and Algeria) and/or they do not plan new LNG investments in the near term (Qatar, Saudi Arabia, UAE).
Uncommitted infrastructure	Import capacity exceeds export capacity for LNG, and some LNG ships are under-utilised. However, this also brings flexibility to the system.
Contract terms	Sellers may use favourable market conditions to negotiate preferred terms, for example on pricing, Take-or-Pay, and cargo diversion rights.

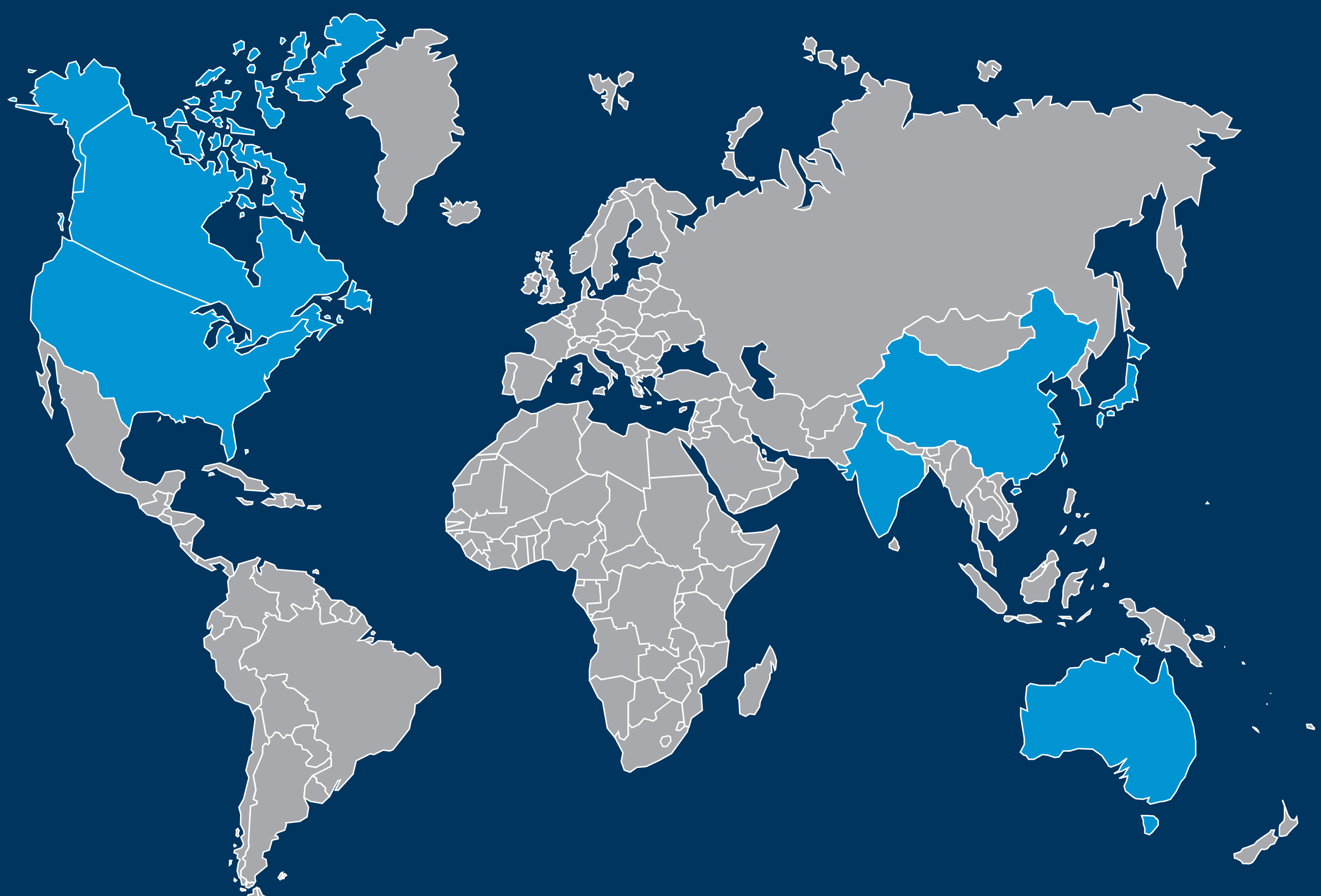
9 Conference for the Association of International Petroleum Negotiators, Singapore 12 June 2008.

The issue	Why is it a challenge?
Financing and credit	Shortage of credit for large projects will influence costs and credit concerns throughout the gas value chain.
New technology risk	There are interesting developments (with new challenges and safety concerns) in relation to large-scale projects, offshore liquefaction, larger ships and new market entrants.
Other risks and uncertainty	Uncertainty in general will impede investments. For example, investors in pipeline infrastructure will look for long term commitments to support the expenditure, and investors in electricity capacity may be put off by uncertainty about policies for greenhouse gas emissions, carbon taxes and the environment. Recent suggestions of a gas cartel between Iran, Russia and Qatar (also referred to as the gas troika) bring further uncertainty to the supply/demand balance.

These issues are similar in nature to those listed in Figure 3.1 although the context is slightly more focussed on short term issues and project development risks than the longer term.

PART B Gas markets in the APP economies

Australia • Canada • China • India • Japan • Korea • US



4 Australia

4.1 Overview – Australia's gas market

Australia's natural gas industry has grown significantly in the last decade and the country is now amongst the world's top six LNG exporters. It is expected that this growth will continue in the short to medium term driven mainly by high international demand for LNG. Nonetheless, Australia's domestic market is also expected to grow significantly, driven mainly by requirements for additional capacity of gas fired power generation in a low carbon economy.

Traditionally, the majority of Australia's natural gas resources are located offshore and in the western part of the country, which are long distances from the more populous eastern states.

A significant development has been the growth in the commercial production of coal seam gas (CSG) in Queensland and New South Wales. CSG resources are conveniently located close to the major consumers (domestic and industrial), so it is expected that CSG will become a significant source of gas supply for the eastern states as well as the feedstock for planned LNG export facilities.

Australia's natural gas market incorporates all stages of the gas supply chain as shown in Figure 4.1.

Figure 4.1 Australia's gas supply chain

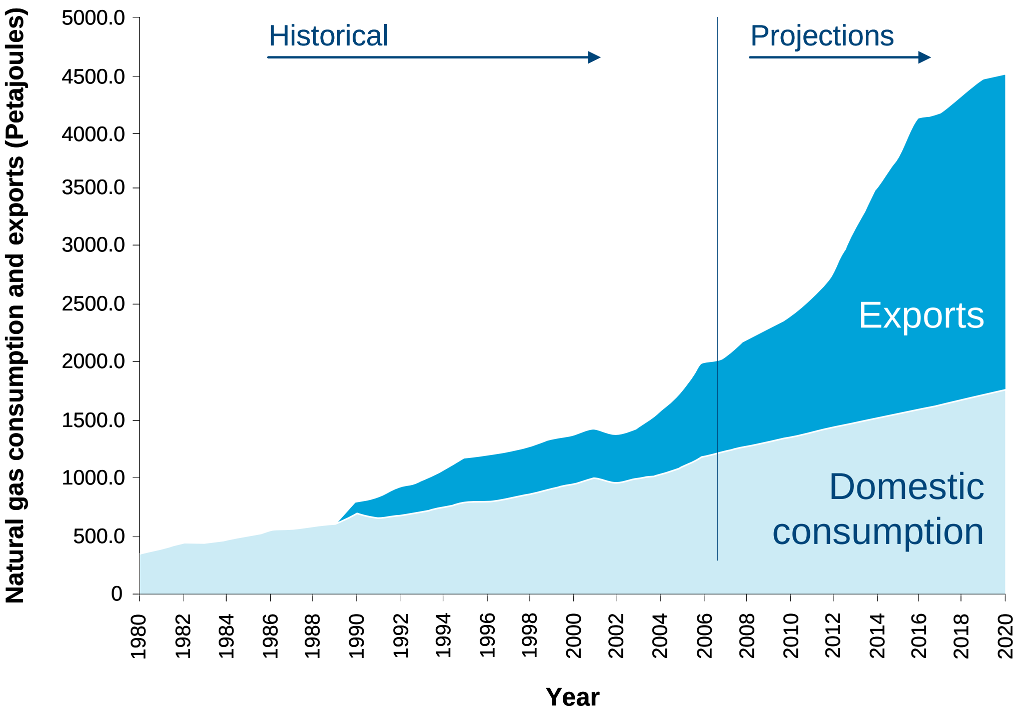
4.1.1 Exploration and production

Australia holds approximately 1.4% of the world's proved natural gas reserves, which represents 88.6 Tcf and is a large quantity in absolute terms. It is also one of the largest gas-producing countries (by volume of natural gas produced) in the world. Statistics from Australia's Department of Resources, Energy & Tourism show proven and probable (2P) reserves of natural gas, as at January 2007, of 153 Tcf. Australia is also considered to be a country with further potential, as it is vast and largely unexplored.

Natural gas production in Australia comes from major basins such as the Carnarvon Basin (in north-west Western Australia); the Gippsland Basin (in Bass Strait, off Victoria's south-east coast); and the Cooper/Eromanga Basins (on the borders of South Australia and Queensland). CSG production primarily comes from the Surat and Bowen basins in Queensland.

Gas production of 1,700-1,800 PJ pa in recent years is expected to increase considerably over the next 10-20 years, as displayed in Figure 4.2, in order to satisfy growing domestic and international demand.

Figure 4.2 Gas production for domestic and international markets



Source: Parliament of Australia Research Paper 1 April 2008, no 25.

Reflecting higher oil prices and the continuing gas demand in Australia, the number of companies involved in gas and oil exploration has expanded since the mid-1990s. However, gas production is relatively concentrated and is mostly undertaken by two or more parties in a joint venture.

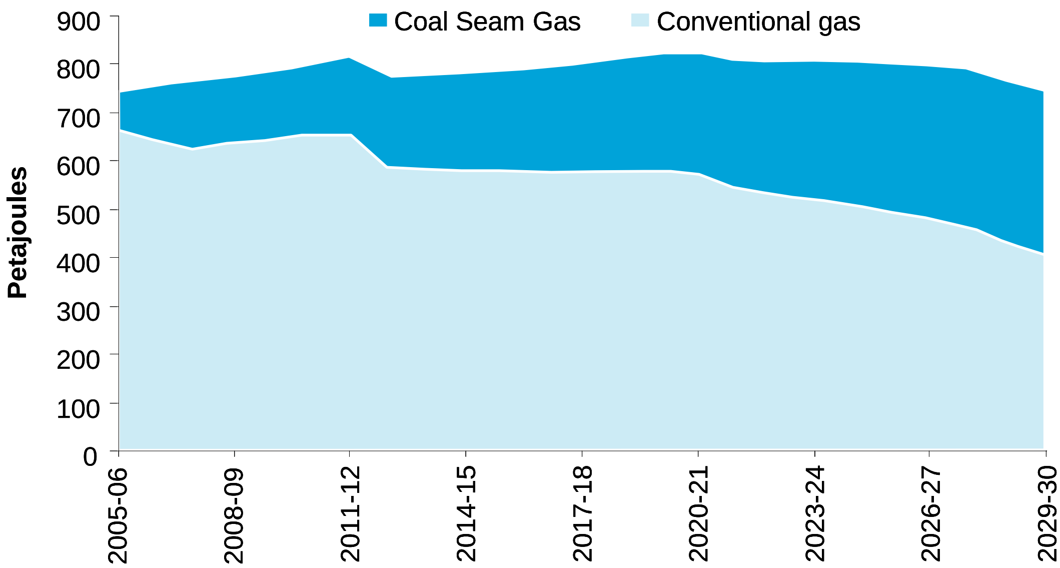
The major conventional natural gas production and exploration companies in Australia are:

- Woodside
- BHP Billiton
- Chevron
- Shell
- BP Australia
- Inpex
- ExxonMobil
- ConocoPhillips
- Santos
- Origin
- ENI
- Apache Corporation

Australia also has coal seam gas (referred to in some other countries as coal bed methane) resources in Queensland and New South Wales, which are beginning to be developed. CSG resources are close to the main demand centres and it is expected that CSG will become a significant source of gas supply for the eastern states. There is uncertainty about how much of New South Wales and Queensland's contingent CSG resources can be developed, and proved and probable reserves stand at 12,375 PJ (11 Tcf).

The production of coal seam gas is rapidly growing in eastern Australia, and is forecasted in Figure 4.3.

Figure 4.3 Production of coal seam gas in eastern Australia



Source: AER – State of the energy markets, 2007 and 2008.

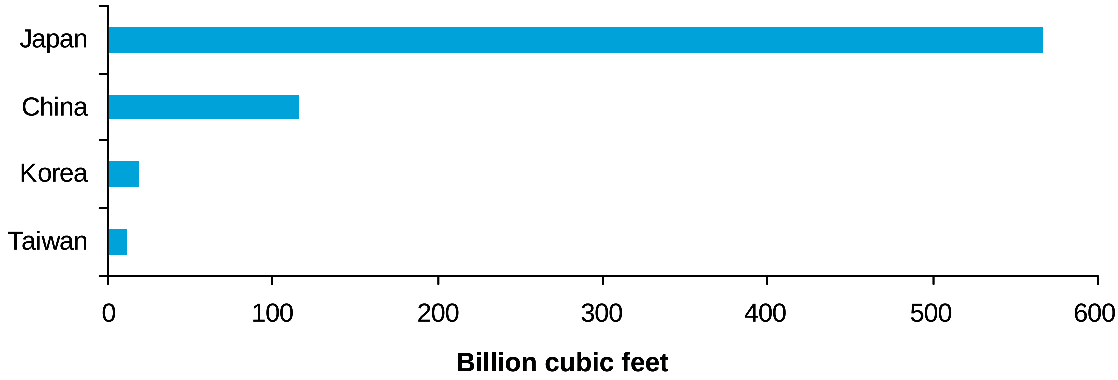
The initial focus on CSG came from the Queensland government's greenhouse gas reduction policies. However, high international prices and the potential for LNG production from CSG may further increase gas production on the east coast.

4.1.2 The export market

Australia began exporting LNG in 1989 and volumes have been growing ever since, with expectations of further growth driven by strong international demand. The Australian LNG industry has developed to become a significant contributor to the Australian economy, and the country is now the sixth largest exporter of LNG in the world. Australia is often portrayed as a country with stable legislative environment and low sovereign risk, thus providing an alternative option for importing countries to diversify its energy sources and improve security of supply.

Australia exported approximately 15 Mt (725 Bcf) of LNG to various destinations in each of the years 2006 and 2007, Japan being the primary one. Australian LNG was also shipped to China, South Korea and Taiwan as displayed in Figure 4.4.

Figure 4.4 Australian LNG exports by destination (2007)



Source: BP Statistical Review of World Energy 2008

LNG exports

Australia currently has two operating gas liquefaction facilities – the Northwest Shelf LNG plant (NWS) in Western Australia (which recently commenced production from the 5th train) and the Darwin LNG plant in the Northern Territory. The Pluto project in the Carnarvon Basin is under construction and may commence production in late 2010 or early 2011.

There are no less than ten LNG projects at varying stages of planning or development, suggesting that Australian LNG exports may increase substantially and in incremental steps over the next 5-10 years. The projects include Gorgon, Browse, Itchys, Greater Sunrise, Wheatstone and Prelude which are all based on offshore conventional gas resources. In addition, there are four or five LNG projects based on coal seam gas resources located near the port of Gladstone in Queensland.

These projects have the potential to position Australia as one of the leading suppliers of LNG in the Asia-Pacific region.

4.1.3 Gas transport and storage

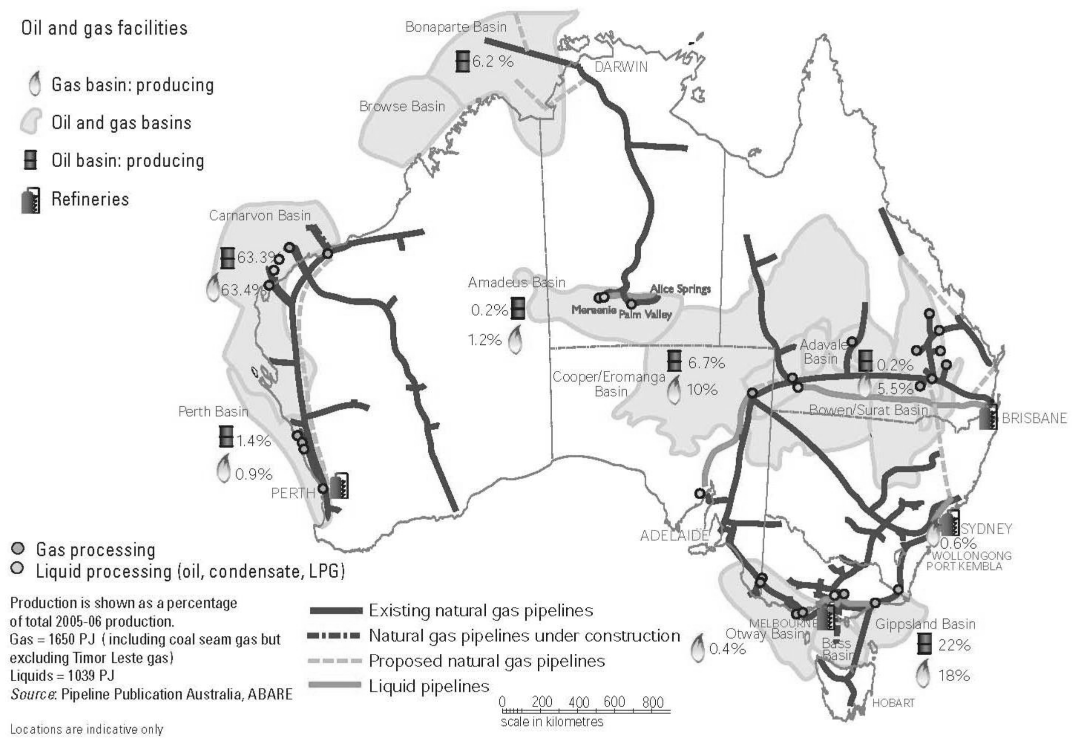
Transmission

Australia's pipeline infrastructure is fractured but well-developed around major demand centres. Natural gas production facilities are linked to demand centres by more than 20,000 km of high-pressure transmission pipelines as per information on the Energy Network Association's website.

Pipelines are predominantly owned by four entities: the Australian Pipeline Trust, Diversified Utilities and Energy Trust, Envestra, and Epic Energy.

The major Australian gas pipelines are shown in Figure 4.5.

Figure 4.5 Major Australian oil and gas distribution facilities



Source: ABARE, Energy in Australia 2008, February 2008

As can be seen, a large portion of Australia's natural gas reserves on the west coast are at considerable distance from the demand centres and there is no transmission infrastructure in place to link them to the east coast. Pipeline transmission infrastructure is adequate for the current gas demand levels but significant new investments will be required over the next 10 years if domestic demand grows as is expected.

Australia is continuing the incremental development of its domestic gas infrastructure. Current and planned projects include increased capacity on the Dampier to Bunbury pipeline in Western Australia, the QSN Link (which will connect Queensland CSG resources to South Australia and NSW) and the South West Queensland pipeline from Cooper Basin to south east Queensland. The Bonaparte gas pipeline in the Northern Territory will carry Blacktip gas to join the existing Amadeus Basin to Darwin gas pipeline

Distribution

The distribution of gas involves transporting gas from a high-pressure transmission network to the end-use customers via a low-pressure distribution network which takes gas from 'citygate' stations to homes, offices and factories.

Australia's gas distributors supply gas to around 3.75 million households and more than 75,000 commercial and industrial enterprises, through over 75,000 km of low-pressure distribution networks.[10]

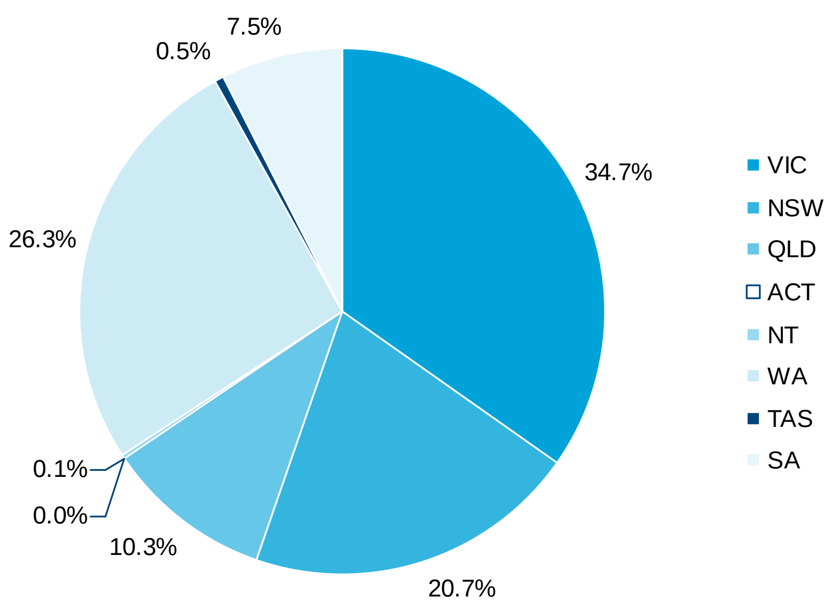
The major Australian gas distribution companies are:

- AlintaGas
- APT Allgas
- Envestra
- Jemena
- SP AusNet
- Multinet Gas.

Some local governments also distribute natural gas, such as at Dalby in Queensland.

Not all regions within Australia have a reticulation network. Gas reticulation is still being rolled out in many areas, and distribution depends on the usage level and expected demand growth for gas in a particular region. Many areas in Australia have limited need for heating throughout the year, which limits the potential for residential demand.

Figure 4.6 Gas distribution in Australia (% by state)



[10] Energy Networks Association website

Tasmania had no access to natural gas until the completion of the Tasmanian gas pipeline in September 2002. The 732 km sub-sea pipeline connects Tasmania to the gas network on mainland Australia via the Eastern Gas Pipeline at Longford in Victoria. Initial users of the gas were Bell Bay Power, Australian Bulk Minerals, Ecka Granules and Comalco Aluminium. Tasmania accounts for well under 1% of gas distributed via domestic gas consumption.[11] It is expected that there will be continuing growth in Tasmania's gas consumption as a result of new gas-fired power generation.

Storage

There are two commercial gas storage facilities in Australia, both in Victoria: Iona underground gas storage and Dandenong liquefaction and storage facility. They are used primarily for gas balancing purposes by the gas utilities.

Australia's need for storage facilities is mitigated by the fact that gas production facilities are generally located close to the main demand centres. Gas production matches demand and Australia relies on spare pipeline capacity to deal with the supply/demand mismatch. This spare capacity acts effectively as gas storage.

Unlike other countries, most of Australia is not exposed to strong seasonal swings in demand. However, Victoria, Tasmania and the ACT experience seasonality in winter demand and the storage facilities do not always solve the problem as they have limited capacity. Whilst if would be ideal to have additional storage facilities in key locations, an option to increase pipeline capacity will also increase flexibility in the markets.

4.1.4 Gas markets

Wholesale market

Despite its wealth of gas resources, Australia's gas markets remain relatively underdeveloped. The wholesale market in Australia is comprised of two components: gas and gas transportation. The gas prices are set by the parties without any government intervention; the transportation prices can be regulated or unregulated, depending on the pipeline.

There is no secondary market for trading gas or gas transportation which means that participants are not able to manage their risk unless they secure long term contracts. Hence, gas it traded mainly under long term, bilateral contracts for both the commodity and the transportation components. Spot gas trading is a very complex exercise in Australia; the ways the markets operate have resulted in constraints on pipeline capacity utilisation and lack of price transparency.

Gas gathered from each basin is principally sold into the nearest market. There is interstate trade but it is very limited, mainly due to the complexities around moving gas from one state to the other.

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11 IBIS, Gas Supply in Australia, March 2008

Retail market

In essence, retailers buy gas from the producers, organise transport and resell it to their customers, dealing with all the contracts and administration in between. In practice, even large customers buy gas through a retailer as going directly to the market is too complex. Large industrial and commercial users are able to negotiate longer-term bilateral contracts with their retailers, and thus protect themselves from the full impact of spot price movements.

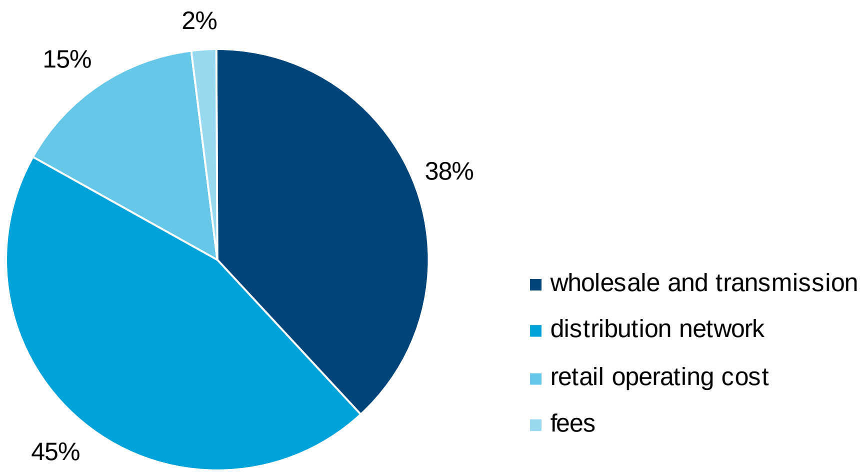
In order to promote retail competition, Australian states and territories have introduced full retail contestability, so even small customers can choose their supplier of choice. Retail pricing to large customers generally consists of a negotiated commodity price plus pass-through of regulated charges. Retail pricing to small customers gives customers a single bundled price: incorporating wholesale gas price, transmission, distribution and storage services.

The lack of transparency in the gas markets and operational difficulties in providing a bundled gas service has created entry barriers. New entrants need to secure long term contracts with producers but may find that most of the transmission capacity is already pre-contracted. New entrants that need to subcontract the spare capacity from one of the existing retailers will be at a considerable disadvantage. As a result, there are few gas retailers in Australia. The major retailers are AGL, Origin, TRUenergy and Alinta. Other smaller gas retailers exist; however, their market share at this stage is insignificant.

Pricing

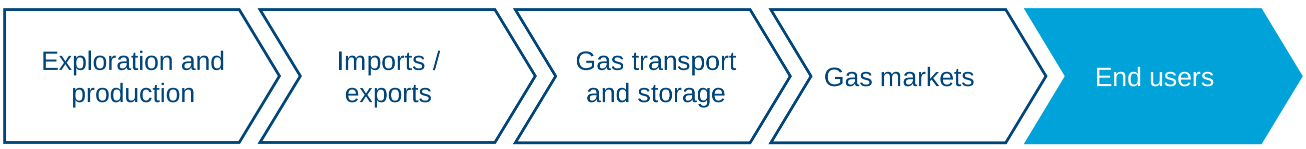
The indicative composition of a residential gas bill in Australia is shown in Figure 4.7.

Figure 4.7 Indicative composition of a residential gas bill (Victoria)



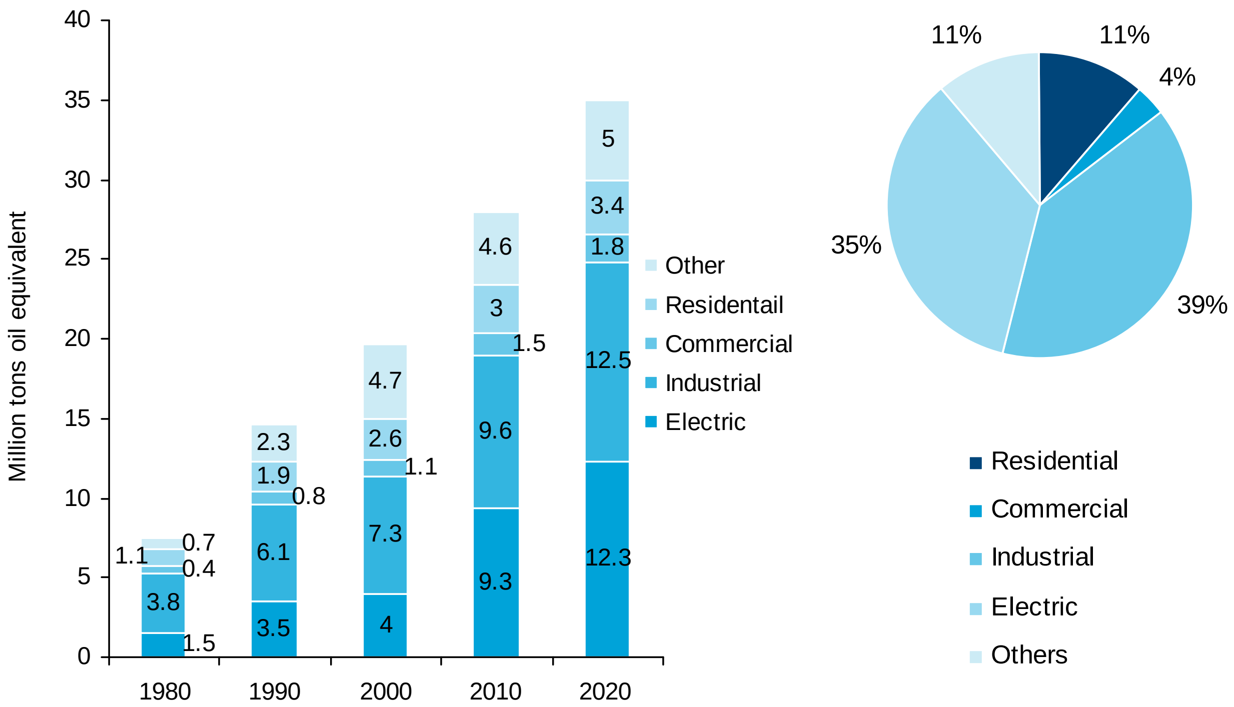
Source: AER report: State of the energy markets 2007

4.1.5 End users



In 2006/07 Australian consumers used 1,115 PJ of natural gas in a variety of industries.[12] The major use is for electricity generation, with over 35% share. Growth of gas by sector and projected growth is displayed in Figure 4.8:

Figure 4.8 Evolution of natural gas use in Australia, 1980 – 2020



Source: ABARE data statistics and data projections

The use of gas in the power generation sector has the potential to grow as a result of an increasing peak load demand for electricity, lower capital expenditure for gas-fired generation technologies compared to coal-fired generation technologies, and environmental benefits associated with burning gas versus coal.

The pending introduction of a Carbon Pollution Reduction Scheme is expected to make gas fired generation more cost competitive relative to coal. However, there is also strong support for coal and renewable energy in Australia.

4.2 Regulatory and legislative environment

Regulation of the Australian energy sector is undergoing significant change. A central focus of energy policy reform has been the development of a national regulatory framework that provides consistency across the gas and electricity sectors.

[12] ABARE, National and State Projections to 2029-30

In 2005, the government established two national bodies – the Australian Energy Regulator (AER) and the Australian Energy Markets Commission (AEMC). The AER is responsible for the economic regulation of both gas and electricity distribution networks in all states and territories except Western Australia. The AEMC is responsible for rule-making, market development and policy advice concerning access to natural gas pipelines services and elements of the broader natural gas industry.

In 2008 the Federal Government created the Australian Energy Market Operator (AEMO), which in 2009 will take over operation of the Victorian gas spot market, the National Electricity Market and the gas retail markets of all states and territories except Western Australia and the Northern Territory.

The Department of Resources, Energy and Tourism provides advice and policy support to the Australian Government. The government created the Ministerial Council of Energy (MCE) in 2001 in order to build policy co-ordination between the federal and state governments. The MCE functions as the director of natural gas policy.

4.2.1 Exploration and production

The Crown owns the petroleum resources. The states and territories have statutory rights to onshore resources and resources in coastal waters, while the federal government controls the resources in offshore waters. The governments co-ordinate their activities through the Ministerial Council on Mineral and Petroleum Resources.

Governments release acreage each year for exploration and development. The rights to explore, develop and produce gas and other petroleum products in a specified area or ‘tenement’ are documented in a lease or licence (also referred to as a ‘title’ or ‘permit’). Australian governments have a suite of exploration titles, each designed for a particular purpose and each with a standard range of qualifying criteria and operating conditions.

A variety of laws apply to the upstream industry, including regulations and guidelines under the Petroleum Act 1967, the Offshore Petroleum Act 2006, Native Title processes, and safety legislation administered by the National Offshore Petroleum Safety Authority and state government agencies.

Offshore petroleum activities are now governed by the Offshore Petroleum Act 2006 (OPA), which incorporates some recent reforms to its precursor legislation, the Petroleum (Submerged Lands) Act 1967. Equivalent legislation exists at the state and territory level so that exploration and production in offshore waters is carried out under a uniform regime.

4.2.2 Imports and exports

Australia has an open market for exports and imports, with no restrictions. The exception is Western Australia where the state government is trying to reserve at least 15% of natural gas for domestic use in order to ensure sufficient domestic supply.

The arrangement in Western Australia has not been well received by LNG developers who claim that such restrictions on LNG projects will hinder rather than benefit the domestic market. The Western Australian market is relatively small and there are no pipeline connections to the east coast.

Liquefaction and export facilities are not subject to economic regulation or third party access arrangements.

4.2.3 Gas transportation

Economic regulation of the gas sector focuses on transmission and distribution. The AER has become the national regulator of transmission and distribution pipelines (from July 2008), following the implementation of the National Gas Law and the National Gas Rules. These replace the current Gas Law and Gas Code.

Access regulation for gas pipelines has been a subject of debate in recent years and there has been some criticism that the gas sector is over-regulated. The new gas framework has a less intensive regulatory regime in the pipeline sector. It could be argued that there has been a tendency towards deregulation. Under the gas code, only a gas pipeline that is a monopoly needs to be regulated.

The providers of covered pipeline services must submit access arrangements to the nominated regulator for approval, and comply with other Gas Code provisions, such as ring-fencing. Access arrangements specify reference services that the pipeline operator must offer and reference tariffs, which form a benchmark as the basis for negotiating services. Reference tariffs may apply to one or more of the pipeline services offered. Most access arrangements apply for a fixed term, usually five years, and are then subject to a review and update.

4.2.4 Gas markets

Wholesale markets

Before the early 1990s, natural gas services operated under separate state-based systems and legislative and regulatory barriers restricted interconnection of pipeline systems across state borders, restricting interstate trade in natural gas. Policy reforms, such as the agreement to introduce free and fair trade in gas between and within the states and territories, and the introduction of regulated third-party access rights to natural gas pipelines, have created trading opportunities for interstate trade and for expansion of the pipeline infrastructure.

The gas market in Australia is a market in transition. It has traditionally been highly regulated in terms of transport and price. This is due to a high degree of concentration of field ownership between Esso-BHP and Santos in the east, and the north-west shelf partners in the west. Transmission infrastructure has been extended in the east to increase customer access, and also to connect new gas fields to the system, including those fields developing coal seam gas.

Only Victoria has an organised gas market at present, but this market is only for the differences and therefore it is not a spot market per se. The gas market in Victoria is operated by VenCorp, which will become part of AEMO.

Gas markets are expected to commence in 2010 for Sydney and Adelaide, with other regions to follow as required. This will bring more competition and price transparency to these markets.

Retail

Gas pipeline legislation, introduced between 1998 and 2000, has prohibited cross ownership between transmission pipelines and distribution/ retail functions, but some states have yet to fully dismantle old legacy systems. The gas sector has seen a wave of mergers and acquisitions since 2006.

All states and territories in principle permit all customers to enter a supply contract with a retailer of their choice.

New South Wales, Victoria and South Australia regulate gas retail prices for small customers. Typically, host retailers must offer contracts to sell gas at default prices based on some form of regulated price cap or oversight. In most instances these contract offers apply to customers who have not switched to a market contract. Western Australia also regulates prices, and there is at present only one licensed gas retailer for small customers.

Retail gas prices are not regulated in Queensland, Tasmania, the ACT or the Northern Territory where there is limited gas reticulation and consumption of gas amongst small customers.

5 Canada

5.1 Overview – Canada's gas market

Canada has considerable natural resources and is one of the world's largest producers and exporters of energy. Canada is the fifth largest energy producer in the world and the third largest natural gas producer (behind the US and Russia). It is a major energy exporter, primarily to the US. The production of natural gas has nearly doubled since 1990 however it is anticipated that the industry's growth will slow down in the near future. Analysts expect that much of the future natural gas production will be derived from coal bed methane (coal seam gas) deposits in many areas: the Western Canada Sedimentary Basin (WCSB), Arctic frontier natural gas deposits, the Deep Basin area in eastern Alberta and offshore natural gas fields. Currently the majority of conventional natural gas resources in Canada are located in the WCSB.

Canada has a well balanced natural gas supply chain which is addressed below:

Figure 5.1 Canadian gas supply chain

The Canadian and US natural gas markets largely operate as one large integrated market. Changes to factors such as costs, infrastructure or climate in one region will impact upon the other regions.

Demand is spread across the country but is concentrated in densely populated areas and in areas of intense industrial activity. Canadian gas production is connected to the North American gas market through a network of thousands of kilometres of pipelines allowing buyers to purchase and transport natural gas from a number of supply sources across the country. Recently, significant gas resources have been used as part of the Alberta oil sands projects. This has had impact on how gas infrastructure is utilised as well as imports availability to the US.

5.1.1 Exploration and production

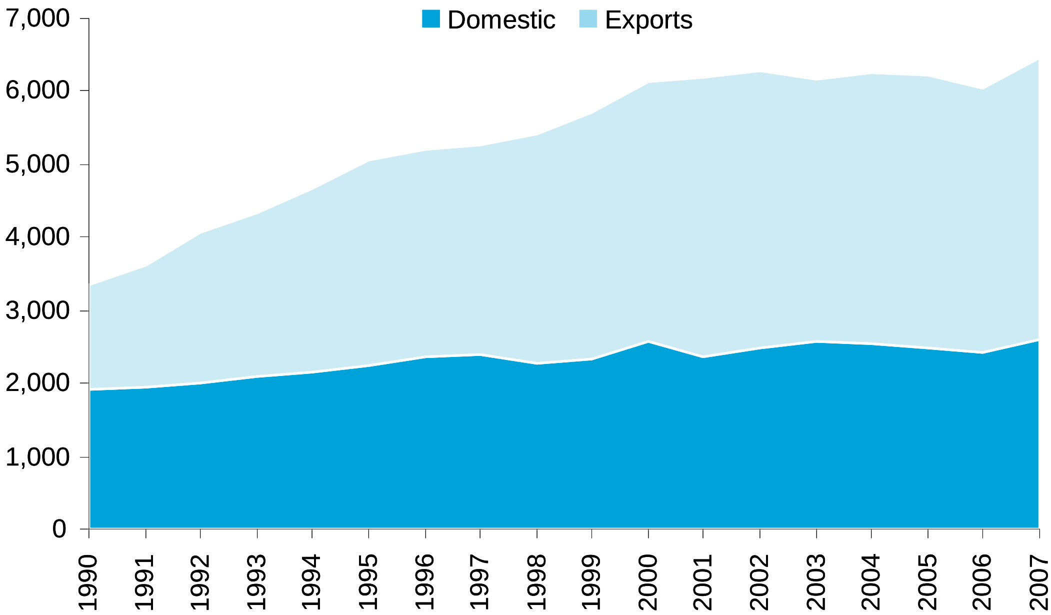
As at 2007, there is an estimated 58.2 Tcf of proved natural gas reserves in Canada, representing more than 9 years of the current production.[13] Natural gas production is concentrated in the Western Canadian Sedimentary Basin (WCSB). This area includes most of Alberta, significant proportions of British Columbia and Saskatchewan, as well as parts of Manitoba and the Northwest Territories.

[13] Natural Resources Canada (NRCan)

Besides the proved reserves, Canada has considerably larger potential resources. When including the remaining reserves, including discovered and undiscovered resources, the lifetime of all resources as estimated by the National Energy Board would increase to 77 years at current production rates.

Canada's production in 2007 was 5.9 Tcf of which 98% was produced in Western Canada. Around 64% of Canada's total production was exported to the US.[14]

Figure 5.2 Canadian gas production



Source: CGA data

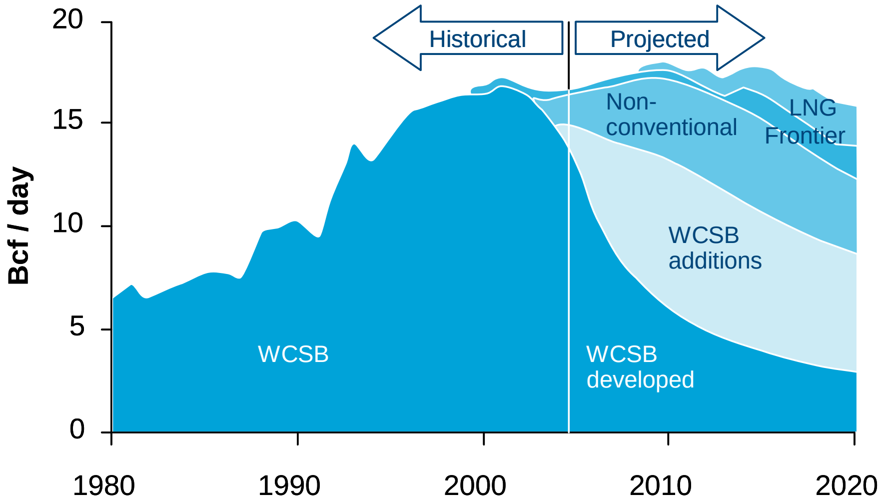
Natural gas supply is increasing from British Columbia and Atlantic Canada. Additional offshore compression is underway at the Sable Island Energy Project, and New Brunswick onshore production is being connected to the pipeline system. The possible resurrection of the Deep Panuke project offshore Nova Scotia is another potential source of natural gas.

Canada's unconventional natural gas resources such as coal bed methane (CBM) can also contribute to meeting future demand. The Alberta Energy and Utilities Board anticipate that by 2014, gas from CBM will represent 12% of Alberta's total annual natural gas production.

Production of conventional gas resources in Canada is becoming scarcer and more expensive. Supply costs have risen as a result of resources becoming more remote from market areas and requiring more advanced technology to extract. Consequently there is a big move to unconventional CBM gas. Canada is a relatively late starter in generating gas from unconventional resources. There is a strong belief that CBM production will eventually replace the decline in conventional natural gas production as projected in Figure 5.3.

[14] Natural Resources Canada (NRCan)

Figure 5.3 Canadian natural gas supply



Source: National Energy Board 2008

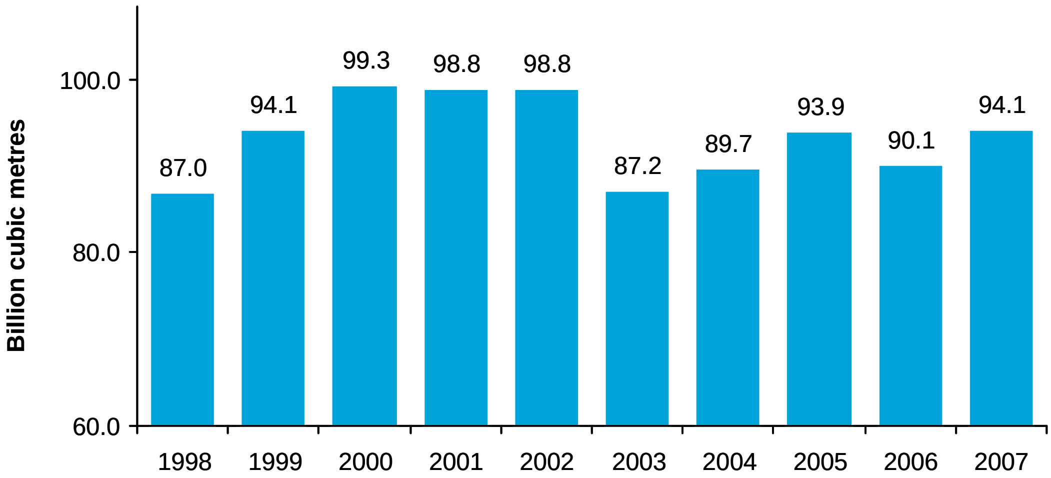
5.1.2 *Imports and exports*

Exploration and production | **Imports / exports** | Gas transport and storage | Gas markets | End users

Pipeline imports and exports

The US and Canadian gas markets largely function as one single market reacting to demand and price signals. This is possible due to a highly integrated gas pipeline network and international agreements such as the North American Free Trade Agreement (NAFTA).

Figure 5.4 Canadian natural gas net export volumes 1998-2007



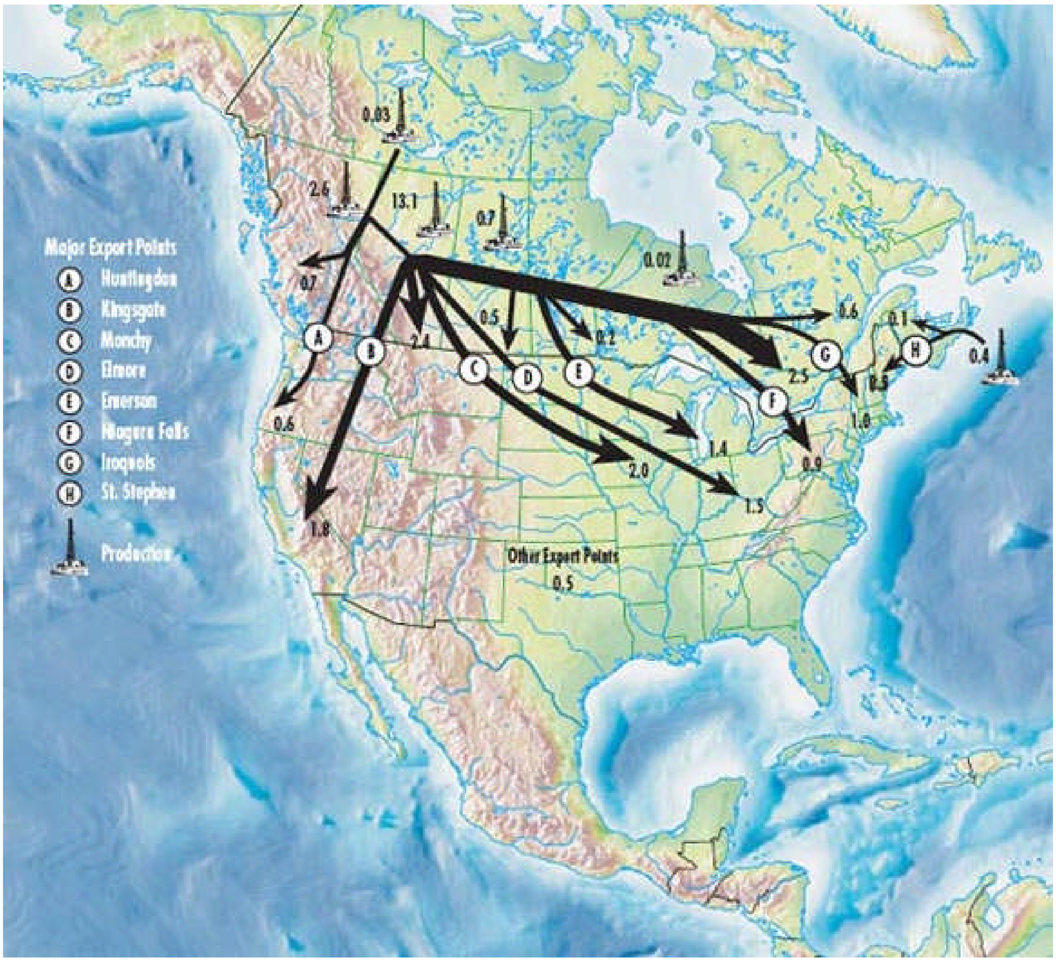
Source: National Energy Board

Several structural factors are currently shaping the market outlook for Canadian natural gas exports to the US. While individually total exports and total imports show an upward movement, the overall trend for Canada's net gas export balance is declining due to:

- Increases in domestic demand for oil sands operations in Alberta and for increased gas-fired power generation in Ontario.
- Lower drilling activity in the WCSB.
- A rise in US unconventional gas production.
- Canadian buyers seeking alternate supply sources like US gas for lower prices or to address lack of local supply such as lower output from the WCSB.

Figure 5.5 summarises the production, exports and imports of natural gas.

Figure 5.5 Canadian natural gas supply and disposition (Bcf/d) – 2007



Source: National Energy Board

LNG projects[15]

In Canada, there are seven proposals to construct LNG import facilities, including three projects in Atlantic Canada, three in Quebec and one in British Columbia. The most advanced terminal is the Canaport terminal being built in Saint John, New Brunswick, which is expected to be operational in 2009. Other terminals could be operational between 2011 and 2015.

In addition, there is one LNG export project proposed for Kitimat, British Columbia. In September 2008, the Kitimat LNG proponents announced their intention to export LNG to Asian markets where LNG prices are higher. This is a complete reversal of the original plan to import LNG at the same location.

Ultimately, market forces will determine how many LNG facilities will be built in Canada. The reversal of the Kitimat business model is one indication of the current uncertainty about North American LNG imports.

5.1.3 Gas transport and storage

Canada has a substantial energy infrastructure already in place. One of their main challenges is how best to replace obsolete facilities in a deregulated environment for gas and power production where utilities are faced with the competitive pressure to reduce costs.

Transmission

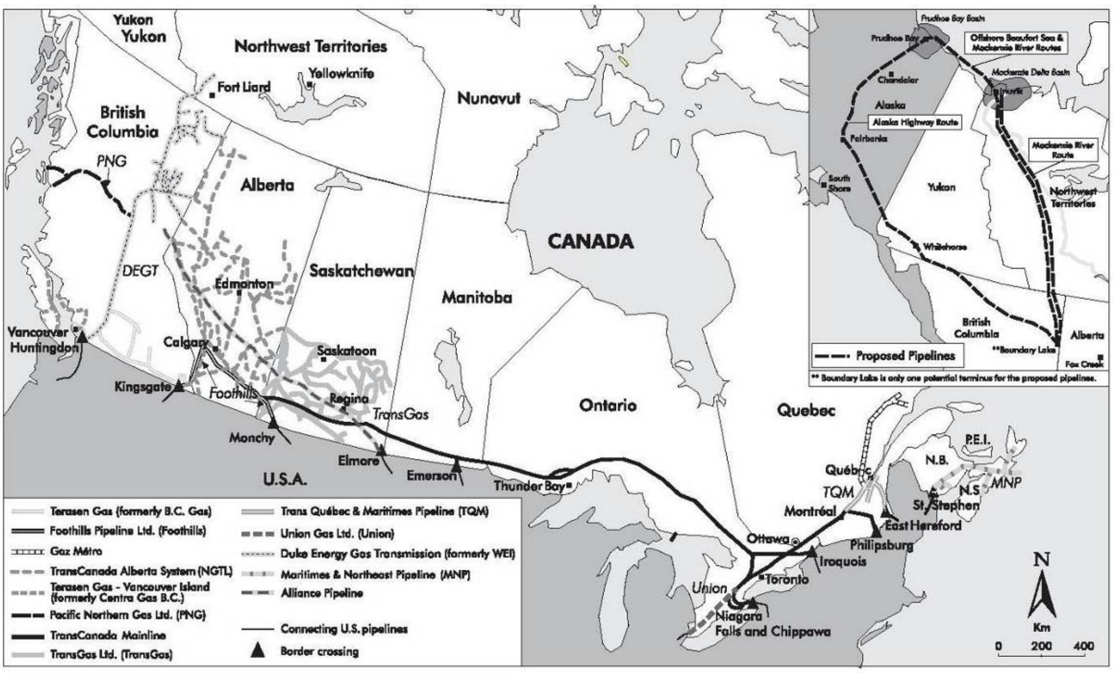
Gas in Canada is transported through a long network of transmission pipelines that connect the natural gas producing areas located in the west to the principal export and domestic markets, located in the east. This network interconnects with the US pipeline grid at about a dozen export points.

There are eight major transmission pipelines, representing approximately 80,000 km of transport capacity carrying gas from the processing plants to the consuming regions and export points at the international border.

[15] Natural Resources Canada (NRCan)

The Canadian gas transmission system is shown in Figure 5.6.

Figure 5.6 Canadian transmission system



Source: IEA, Energy policies of IEA countries, Canada 2004 review

TransCanada is the major gas transmission owner and operator in Canada. It owns an extensive network of high pressure pipelines covering 59,000 km and taps into nearly all the major gas supply basins.

Distribution

Local distribution companies (LDCs) receive gas from pipelines and deliver it to end users.

Currently there are 11 gas distributors in Canada. There is a single owner and operator of the natural gas distribution network in Saskatchewan, Manitoba and New Brunswick. In Quebec, there are two companies distributing natural gas, with one being a dominant player controlling almost the entire market. There are two companies with a substantial share of the distribution grid in Ontario and three in British Columbia. Although in Alberta a single distribution company holds 80% of the market there is also another investor-owned utility, 24 municipal utilities, and 69 rural cooperatives.

Storage

There is substantial upstream storage capacity in western Canada and downstream storage in eastern Canada. This expensive storage mitigates supply disruptions and smooths out the high seasonality of demand. Upstream storage is being expanded in the producing regions.

Storage is also essential to meet peak demand. It enables gas distribution companies to manage the peaks and take advantage of any short term spikes. Downstream storage is increasingly used by local distributors, end-users, marketers and pipeline companies to increase the reliability of gas supplies.

Natural gas is stored underground or as liquefied natural gas (LNG) in insulated tanks. Canada and the US have a number of 'peak shaving' localised LNG-based facilities typically in areas where no natural storage capability exists. LNG is often used to meet "peak" natural gas demand during winter.

Changing gas flows

The historical flow of gas from production areas to consumption centres in eastern Canada and the US has begun to change in the last few years. The combination of three factors is resulting in these changes to gas flows:

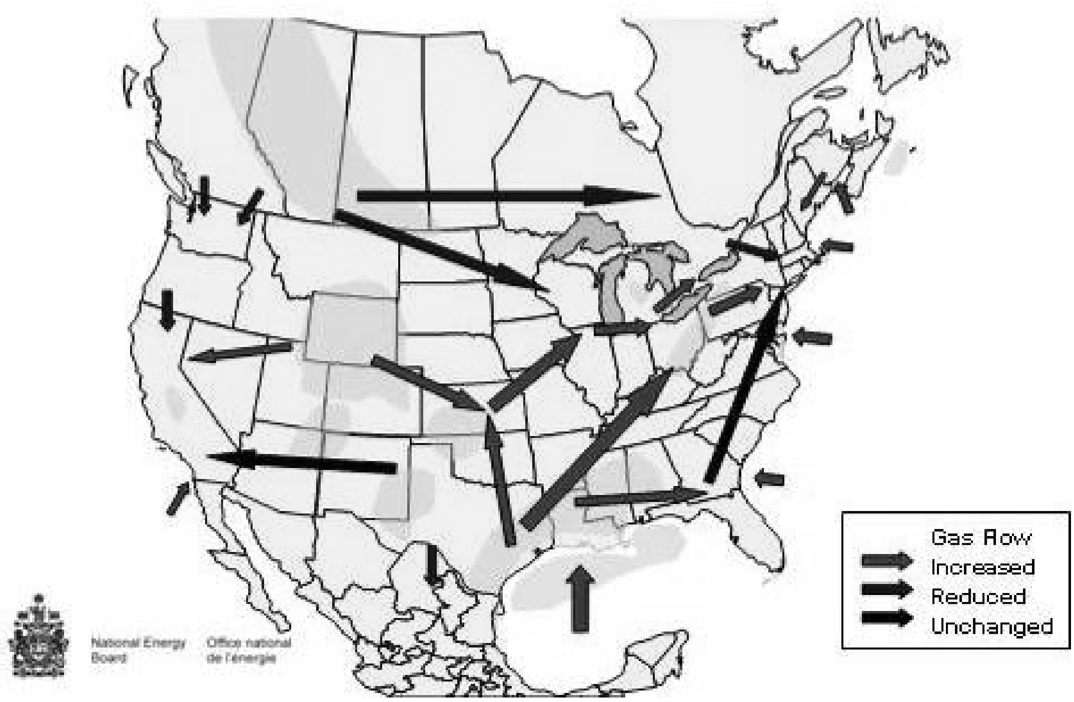
1. An increase in domestic demand for gas.
2. A decline in domestic production.
3. Increasing international competition with US imports of LNG and gas from unconventional gas production in the US Rockies and from the shales of east Texas, Louisiana and Arkansas.

For example, the growing use of natural gas within Alberta to extract oil from the oil sands means that gas available for export from Alberta has been reduced reduced. Also, due to their location and competing gas prices, gas powered generation plants in Ontario may need to be increasingly served from gas flows from the US.

The reduction in gas exports due to increased local demand has challenged the adequacy of the existing gas infrastructure.

Changes in gas flows have important implications for pipeline capacity. Spare capacity in some pipelines is creating problems as huge investments have been made for little return.

Figure 5.7 Potential gas flow impacts



Source: National Energy Board

Transmission contracts have traditionally been long term arrangements but new contracts are increasingly short term. Therefore the cost of transportation is essentially changing from a fixed to a variable cost.

5.1.4 Gas markets

Wholesale markets

Natural gas is bought and sold in a large integrated continental market with multiple pricing hubs. Canadian natural gas production is connected to the North American market through an extensive pipeline network that allows buyers and sellers to transport natural gas from numerous different supply sources around the continent.

Natural gas transfers on the TransCanada Alberta System represent the main Canadian pricing hub (AECO ‘C’) while the Henry Hub in Louisiana is the pricing point for natural gas traded on the New York Mercantile Exchange (NYMEX). The price of natural gas traded at these hubs is publicly posted and traded on multiple trading platforms, setting a transparent commodity cost for natural gas.

The Canadian gas market actively trades in spot, medium and long term gas deals as well as using futures, forwards and options to actively manage price risk. Along with the US, Canada is one the most active markets in the world for gas.

Retail markets

There is a competitive retail gas market in every Canadian province. Large provinces have both multiple retail marketers and producers offering gas to smaller customers. In principle all consumers can choose between supply from retailers or producers. For smaller customers who do not choose to purchase gas from a retail marketer, provincial authorities and regulatory boards ensure that LDCs pass the natural gas commodity cost directly to consumers without marking it up.

Pricing to consumers

In most jurisdictions, the total price paid by end-users of natural gas is made up of the following components:

- Commodity costs: the price paid for the natural gas commodity which is priced at a supply or market hub.
- Transmission costs: the charge to move the natural gas from sources of supply to a city gate of the LDC.
- Distribution costs: the cost to move gas over a LDCs franchise area, including service charges for storage and load balancing.

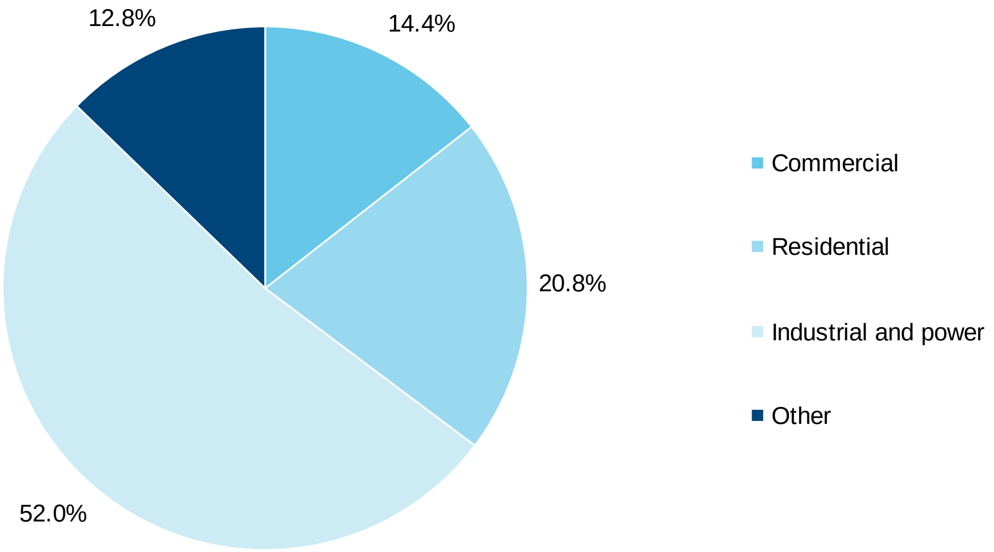
In general transportation and distribution costs are regulated by government agencies and change only moderately over time. The commodity cost makes up most of the final cost to consumers and will change in response to supply and demand conditions.

5.1.5 End users

Approximately one quarter of all energy consumed in Canada is natural gas with estimated consumption in 2007 of about 3.1 Tcf, or about half of Canadian gas production.

Domestic demand for natural gas is split between the following sectors, as shown in Figure 5.8.

Figure 5.8 Natural gas consumption by sectors in 2007



Source: Natural Resources Canada (NRCan)

The residential and commercial sectors account for 35% consumption. Gas usage within the electricity sector represents a small proportion of the industrial demand, but this is a potential growth area.

Natural gas is primarily consumed in the residential and commercial sectors for space heating. In the industrial sector it is used mainly for process heat, as a building block in chemical production, or to produce electricity.

Significant demand growth in Canada is coming from growing gas consumption in oil sands developments in Alberta and new gas-fired electrical generation in Ontario. The gas at the tar sand projects is the primary energy resource to process the sand into synthetic crude oil.

Although privately-owned vehicles fuelled by natural gas play a minor role in terms of transportation use, Canadian companies have developed and exported advanced technology applicable to gas-powered heavy duty vehicles such as buses. As concerns grow about climate change, natural gas is increasingly valued as the cleanest burning fossil fuel available today.

5.2 Regulatory and legislative environment

Canada is the world's second largest exporter of piped gas. The market price of natural gas has been deregulated since the mid 1980s, but transmission tolls, distribution and storage fees, return on equity of businesses and a number of other areas remain regulated or controlled by provincial regulators or the National Energy Board (NEB).

Jurisdiction over energy policy is divided between the federal and provincial governments. The provinces generally own energy resources, and develop energy policies and regulations associated with the management of those resources. Federal powers are concerned with federal land (mostly in the offshore and the Arctic), inter-provincial and international movement of energy and energy-using equipment, and projects extending beyond provincial boundaries.

The major piece of legislation concerned with inter-provincial and international movement of energy is the NEB Act. The act regulates the construction and operation of pipelines and the exportation of oil and gas resources.

The NEB is the key regulatory agency for international and inter-provincial trade, and regulates international and inter-provincial pipeline tolls and tariffs. Provincial agencies regulate activities under provincial jurisdiction including resource development and natural gas distribution. The key policy-making institution is Natural Resources Canada (NRCan).

5.2.1 Exploration and production

Upstream development is carried out essentially under the responsibility of the provinces. For example, The Alberta Department of Energy is responsible for the administration of the Mines and Minerals Act, which sets out the requirements for the responsible development of Alberta's non-renewable mineral resources. In Alberta 81% of the subsurface mineral rights are owned by the Crown. Companies are granted the right to explore for and develop petroleum and natural gas resources, in exchange for royalties, bonus bid payments (the amount of money offered or bid for the mineral rights) and rents.

The Oil and Gas Fiscal Regimes of the Western Canadian Provinces and Territories report (updated 31 January 2008) summarises the petroleum fiscal regimes for the western Canadian provinces and territories. Descriptions are provided for each resource commodity: oil sands, crude oil, and natural gas and natural gas by-products.

The Canada Oil and Gas Operations Act provides regulations concerning installations used in the exploration, development and production of oil and gas in areas not covered by a joint management and resource sharing agreement, such as with Newfoundland in 1985 (the Atlantic Accord) and with Nova Scotia in 1986 (the Canada-Nova Scotia Accord). The Act prohibits any work or activity related to the exploration or production of oil or gas unless one first obtains a license or authorisation issued by the NEB. As part of the application process, a plan must be submitted which shows that Canadians are being employed and that Canadian goods and services are being used. The NEB may require that certain conditions are met, including obtaining appropriate insurance or performing environmental studies.

5.2.2 Transmission and storage

Inter-provincial natural gas transmission pipelines are regulated by the NEB to ensure open, non-discriminatory access is provided to all shippers. The NEB sets transportation rates which are publicly known and are the same for all customers.

Development of the transmission network is left to the market, although international and inter-provincial transportation rates, conditions of access and terms of service are regulated by the NEB.

'Settlement agreements' on rates are often negotiated by large groups of shippers directly with the pipeline company. These agreements are then forwarded to the NEB for consideration in its rates decision. The NEB has powers to hold public hearings if considered necessary.

5.2.3 Distribution

Distribution is carried out by 16 local utilities that have a regulated monopoly over the physical distribution of gas. Third-party access to the distribution grids is allowed and some large industrial customers and power generators can buy gas directly from producers. Some smaller customers in the residential and commercial sectors can also buy gas from producers through aggregators, brokers and other middlemen.

LDCs are mainly privately owned and are regulated at the provincial level by public utility commissions. The commissions regulate the rates charged by the companies for services, and authorise construction of transmission and distribution lines, including approving and recommending the granting of a franchise area. Public utility commissions ensure that rates are fair, that gas supplies are secure and that environmental issues are addressed. Most commissions impose minimal supply conditions on agents, brokers and marketers. In contrast, LDCs are usually required to hold natural gas supplies to cover all their direct sales for a number of years.

5.2.4 Gas markets

From 1975 to 1984, the price of natural gas was regulated in Canada and companies were required to demonstrate that Canada had a minimum 25-year inventory of reserves as a condition for receiving approval for exports. A 1985 agreement between the Federal government and the provinces of Alberta, British Columbia and Saskatchewan deregulated natural gas prices at the wellhead effective November 1986. In Alberta abundant supplies and inability to export resulted in a steep price decline that persisted until the late 1990s. Prices rose gradually as existing pipelines were expanded and new networks were built to supply to new markets.

A similar deregulation process occurred in the US during the mid 1980s, resulting in an open and integrated North American wholesale natural gas market. This structure was strengthened in 1989 by the Canada-US Free Trade Agreement and the NAFTA in 1994.

Since deregulation, wholesale gas prices are set by the market and are predominately linked to the US gas prices. This integrated market works very efficiently, with gas able to easily move between markets to resolve potential supply issues.

5.2.5 Retail competition

Natural gas distribution utilities in Canada have been given franchise areas to serve customers. Generally local municipalities grant a franchise to the natural gas distribution company to serve the residents and businesses of their municipality for a specified period of time.

It is estimated that more than half of Canadian natural gas is purchased directly by customers or their agent, marketer or broker intermediary. The balance of natural gas purchases are made by regulated LDCs on behalf of their customers. LDCs purchase gas using a mix of spot-price and fixed-price contracts and use financial instruments to manage price volatility. LDCs however, are often restricted by their provincial regulator from directly offering their customers the flexible pricing options available from marketers. For example, many regulated LDCs are not able to offer their customers fixed price contracts and must charge customers their variable rates of natural gas price.

Agent/Broker/Marketers are very active in the large markets but this function is primarily done by gas distributors in other provinces.

Retail gas competition has been developing in a number of provinces for some years. The legislative impediments that tied title to the utility made the market less effective and competitive and some consumers complained that they did not receive their negotiated rebates. By allowing title of gas to be held by the supplier, legislation passed in 1998 has permitted the re-emergence of competition. Clarification of the role of distribution utilities as the supplier of last resort and setting out the financial obligation for providing supply remain contentious.

5.2.6 Imports and exports

The NAFTA enacted at the beginning of 1994 is a cornerstone in Canada's energy policy that emphasises the importance of competitive market behaviour and encourages investment in Canadian energy markets.[16]

Since the Free Trade Agreement of 1988 had lifted most barriers to trade between Canada and the US, NAFTA did not result in any significant regulatory changes.

The NEB is required by the NEB Act to ensure that export licences are given only if natural gas exports are surplus to reasonably foreseeable Canadian requirements. In July 1987, the NEB adopted a procedure known as Market-based Procedure to make this assessment. The basic premise of the procedure is that the market will work to satisfy Canadian requirements for natural gas at fair market prices. For this to be fulfilled markets must be competitive, and there should be no abuse of market power with all buyers having access to gas on similar terms and conditions. These conditions were considered to be fulfilled by the Agreement on Natural Gas Prices and Markets signed in October 1985 between the Canadian government and the three gas-producing provinces of British Columbia, Alberta and Saskatchewan. The agreement allowed gas buyers to directly contract for supplies with producers, marketers and other agents at freely negotiated prices.

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[16] Overview of Canada's Energy policy, Natural Resources Canada

6 China

6.1 Overview – China's gas market

The gas market in China is still in its infancy, with most of its gas delivery infrastructure having been developed over the past decade. Gas represents only a minor percentage of overall primary energy consumption.

It is expected that an increasing pressure to reduce the greenhouse gas emissions will play a significant role in the development of gas utilisation and the further development of gas infrastructure. This will include additional LNG re-gasification facilities in coastal provinces, as well as the development of non-conventional gas resources thus advancing the availability of gas throughout the country. China has only recently started to import LNG; however it is becoming a significant importer of natural gas and a major player in the international LNG market.

China's energy needs have grown significantly in the last decade, and it is the twelfth-largest natural gas consumer. Natural gas is an important aspect of China's energy strategy as the country actively seeks new and cleaner sources of energy. Energy usage, together with anticipated strong economic growth, is expected to drive China's demand for energy over the next 10-15 years.

Historically, natural gas usage was limited to producing areas in the west of the country. This has changed due to accelerating demand for energy, along with increasing availability of natural gas, in the eastern and costal regions.

China has a vertically integrated gas market which incorporates all stages of the gas supply chain.

Figure 6.1 China's gas supply chain

6.1.1 Exploration and production

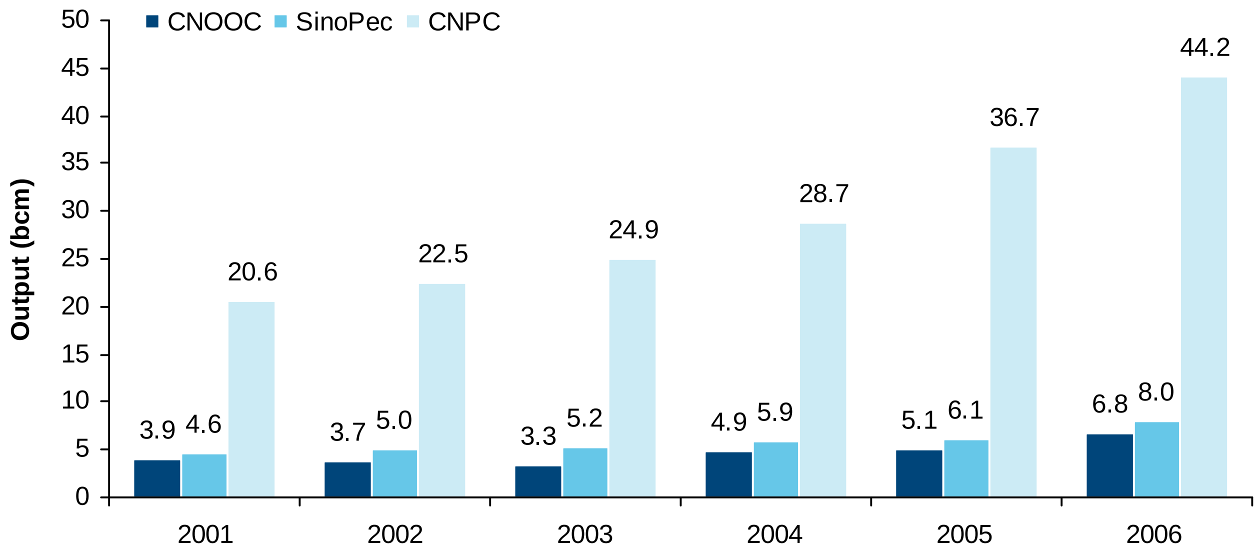
China's domestic natural gas exploration and development industry has been growing rapidly since 2000. Natural gas production has jumped from around 958 Bcf in 2000 to 2,447 Bcf (69 Bcm) in 2007, with a compound annual growth rate of 14%.

The major onshore reserves of natural gas are located in the west and north-eastern areas. It is estimated that China holds 66.5 Tcf of proven natural gas reserves as at the end of 2007, accounting for around 1.1% of the global proven natural gas reserves, and ranking 19th worldwide.[17]

There are six main onshore reserve areas: Sichuan basin, Tarim basin, Ordos basin, Junggar basin, Qaidam basin and Songliao basin. The Sichuan basin has the largest output, accounting for 22% of China's total in 2006. Its proven gas reserves in place at the end of 2004 were more than 28 Tcf.

China's upstream natural gas is dominated by PetroChina, which owns over 80% of the national proved reserves. Its production of natural gas was 78% of the national total in 2007. Total national oil company natural gas output is displayed below and shows the dominance of China National Petroleum Corporation (CNPC), the government-owned parent of PetroChina.

Figure 6.2 National oil companies' output



Source: PetroChina 2007 Annual Report, Sinopec 2007 Annual Report, CNOOC 2007 Annual Report. CNPC publications

National oil companies (NOCs)

PetroChina is the largest gas producer in China. Its activities are focused in onshore northern China. It was listed as a public corporation on the Hong Kong and New York stock exchanges in April 2000, with the China National Petroleum Corporation holding a controlling stake. In 2006, PetroChina overtook BP and Royal Dutch Shell to become the world's third-largest oil company after its market value surged by 37%.

China Petroleum and Chemical Corporation (Sinopec) is the second-largest gas producer in China. Its activities are focused in onshore southern China. In 2007 Sinopec produced 283 Bcf (8 Bcm) of natural gas. The principal operations of Sinopec and its subsidiaries include:

- Exploring, developing, producing and trading crude oil and natural gas; processing crude oil into refined oil products

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[17] Reserve and production figures from BP Statistical Review of World Energy 2008.

- Producing, trading, transporting, distributing and marketing refined oil products
- Producing and distributing chemical products.

Based on 2007 financial turnover, Sinopec is the largest listed company in China.

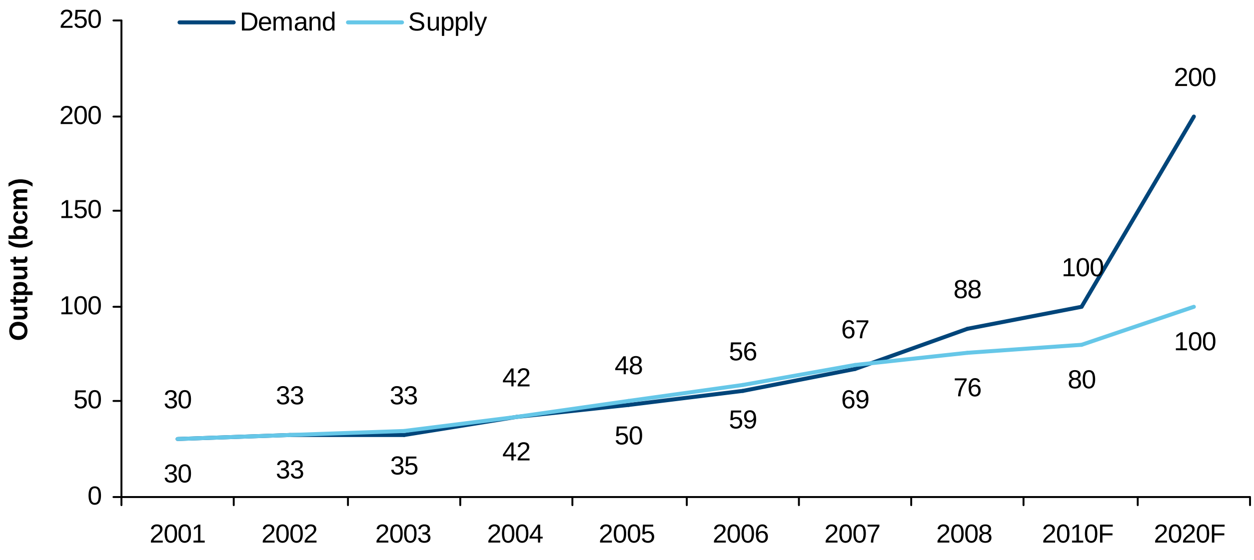
The China National Offshore Oil Corporation (CNOOC), founded in 1982, is one of the largest state-owned oil companies in China, as well as the largest offshore oil and gas producer. It is authorised to co-operate with foreign partners for oil and gas exploration in China's offshore areas. CNOOC operates the first LNG re-gasification project in China – the Guangdong LNG Project, which started production in May 2006. Through this project and other LNG projects under construction (in Fujian, Zhejiang and Shanghai) CNOOC has secured its leading position in the LNG sector in China.

6.1.2 Imports

At present, natural gas only accounts for around 3% of China's total primary energy supply. Driven by the increasing rate of urbanisation and the increasing demand for clean, efficient energy, demand for natural gas is expected to reach 3.5 Tcf (100 Bcm) in 2010 and 7 Tcf (200 Bcm) in 2020. However, domestic supply will struggle to match the simultaneous growth in demand, which would result in a deficit of 0.7 Tcf (20 Bcm) in 2010 and around 3.5 Tcf (100 Bcm) in 2020.

In order to ensure a balance of supply and demand, China will need to import both piped natural gas and LNG. As domestic and piped imported gas is limited, China's LNG imports are projected to reach 8.8 Mt pa in 2010, which will account for 60% of total natural gas imports.

Figure 6.3 Gas supply and demand forecast

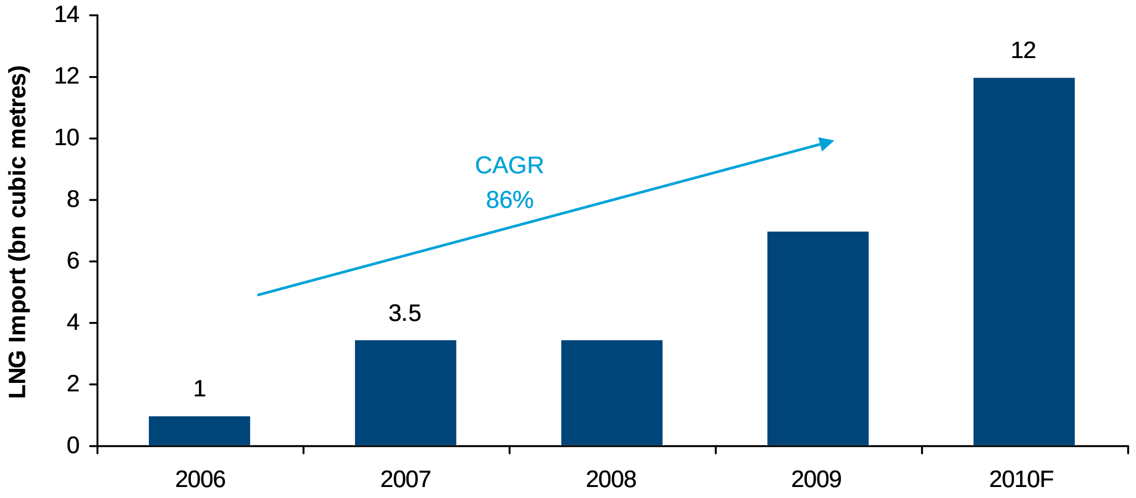


Source: China's natural gas industry and gas to power generation, The Institute of Energy Economics Japan, July 2007

China's LNG market overview

China's LNG imports reached 2.6 Mt (3.5 Bcm) in 2007, which is an increase of 200% from the year before. Imports will continue to grow with the compound annual growth rate expected to exceed 80% over the next couple of years. At present, the two key supply issues faced by LNG terminal operators are the price gap between domestic gas and the international LNG market, and supply availability.

Figure 6.4 China's LNG imports from 2006 to 2010



CAGR: Compound average growth rate

Source: www.jrj.com.cn, Goldman Sachs Report, www.oilnews.com.cn, www.oilnews.com.cn, Invest in China, www.fdi.gov.cn,National Bureau Statistics of China, www.pr-inside.com, www.reuters.com

The government has expressed a preference for LNG from Australia and Indonesia, while minimising dependency on Qatar and other Middle East countries because of political risk. In order to minimise transport risk, China will build at least 30 LNG carriers over the next ten years to transport LNG from abroad.

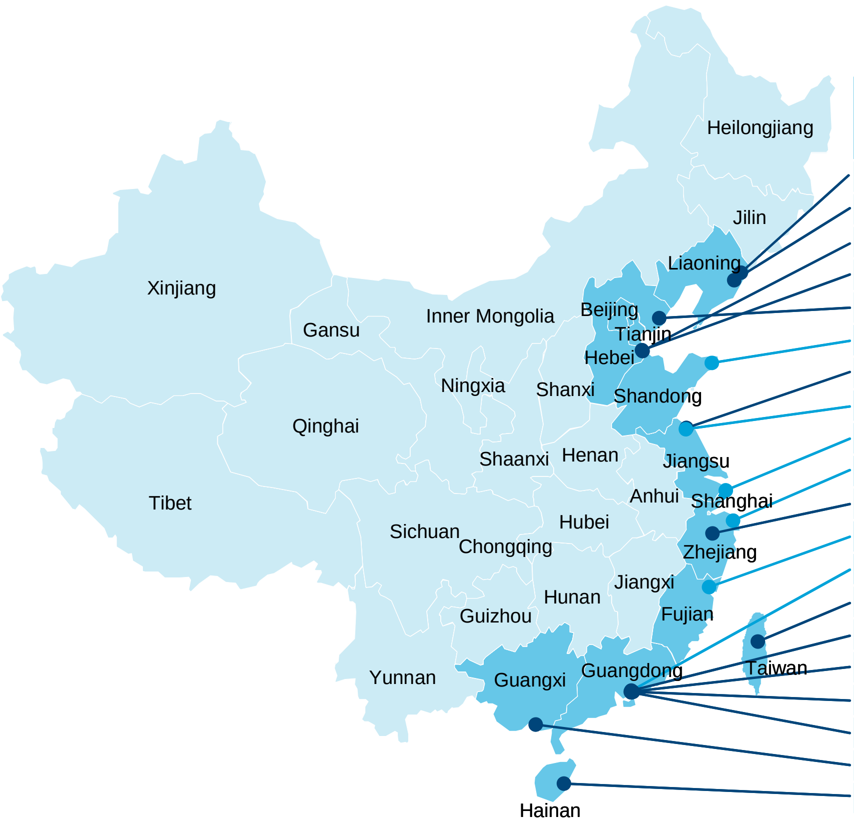
Re-gasification facilities

To meet the rising demand for natural gas, the three NOCs have built or are currently building LNG re-gasification facilities.

There are two currently in operation – Guangdong LNG Project and Fujian Putian LNG Terminal – and others that are either proposed, planned or under construction in all 14 of the coastal provinces.

Chinese companies are establishing a portfolio of LNG supply contractors, expected to include supplies from Australia, Qatar, Oman, Indonesia, Malaysia and potentially other countries.

Figure 6.5 Existing and planned LNG terminals in China



Location	Phase 1 volume (mtpa)	Start operation
Dalian Liaoning	2.0	2008
Yingkou Liaoning	3.0	n/a
Tangshan Hebei	6.0	2010
Qinhuangdao Hebei	2.0	2010
Tianjin	2.5	2010
Qingdoa Shandong	3.0	n/a
Binhai Jiangsu	3.0	n/a
Rudong Jiangsu	3.0	2011
Yangshan Shanghai	3.0	2009
Ningbo Zhejiang	3.0	2008
Wenzhou Zhejiang	n/a	n/a
Putian Fujian	2.6	2007
Dapeng Guangdong	3.7	2006
Taiwan		
Macau		
Shantou Guangdong	2.5	2010
Zhuhai Guangdong	3.0	2010
Hong Kong	3.0	2011
Guangxi	3.0	2010
Haikou Hainan	2.0	2009

Source: China Electricity Council

Of the three NOCs, CNOOC is the clear leader in the LNG market. Around 61% of existing and planned/proposed terminals are or will be operated by CNOOC. PetroChina accounts for 22%, and Sinopec about 11%. Most existing LNG terminals are operated jointly by the national oil companies and local partners or MNCs. BP and Pacific Oil and Gas, part of the Singapore-based RGM International, are the only two foreign LNG project partners so far.

The key element for commercialising the re-gasification terminals is securing gas supplies through LNG gas supply agreements. These agreements may fulfil the terminal facilities entirely with one contract or may require several contracts to meet the capacity of the terminal.

Pipeline imports

In February 2008 China began work on its second west-to-east natural gas transmission pipeline. It will mainly carry natural gas from Turkmenistan and China's Xinjang Uygur Autonomous Region to the Yangtze and Pearl River deltas, the country's two most developed regions. Construction of the 9,102 km pipeline, which consists of a main line and eight sub-lines, will cost approximately US$ 20 billion.[18]

[18] Chinese Government Official Portal, 22/02/2008

There is one cross-border gas pipeline transporting natural gas from Yacheng 13-1 gas field to Hong Kong. CNOOK, BP and KUFPEC of Kuwait have formed a joint venture for the Yacheng 13-1 gas field which provides gas for the Black Point 2,400 MW combined cycle power station.[19]

In North-East Asia, China is considering three possible routes for additional pipelines:

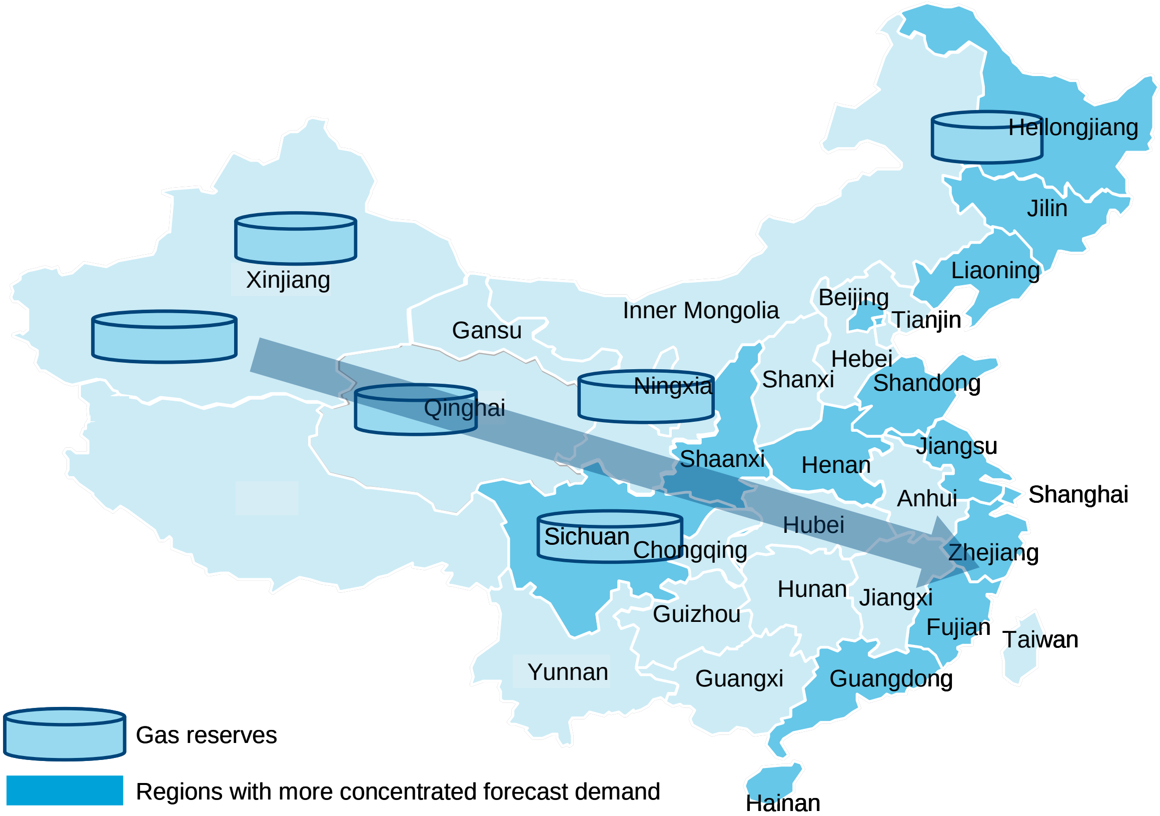
- Sakhalin 1 (Russia to China) – Russia through North-East Asia to China and possibly Korea
- Kovykta (Russia to China/Korea)
- West Siberia (Russia to China).

6.1.3 Gas transport and storage

China started building up its major trunk pipeline capacity for transferring natural gas from the west to the coastal regions in 1996. When these pipelines are completed, the majority of gas will be directed to the eastern and coastal areas.

[19] Natural Gas markets in APP Countries with a Special Focus on India and China: Regulatory Issues, Cross-Border Trade, and Evolving LNG Contract Structures, East West Centre, July 2007

Figure 6.6 Moving natural gas from west to east

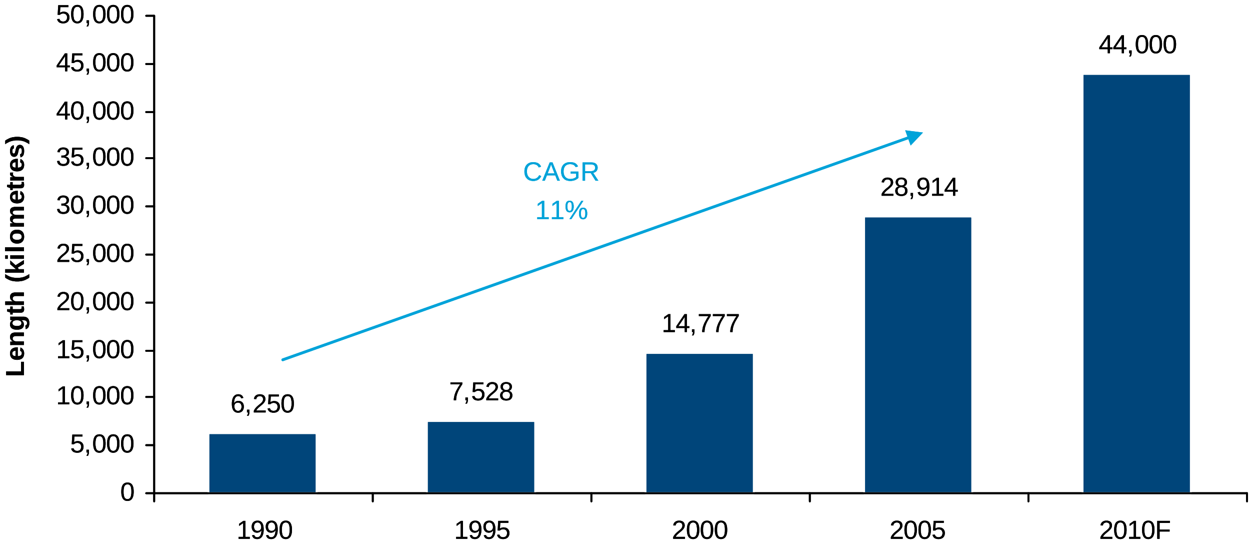


Sources: the booming oil gas market in China 2007 Dingdian finance, China Energy Statistical Yearbook 2006, the Development Prospect for China's Natural Gas Pipeline.

Trunk pipeline capacity has reached a critical mass and is evolving to meet the demand for west-to-east transmission requirements. Storage capacity is increasingly an issue which will need to be addressed to account for seasonal gas requirements.

China will need to construct more pipelines and storage facilities to meet the rising demand of the fast-developing economic regions. According to the 11th five-year plan for natural gas pipelines, an additional 16,000 km of pipelines will be constructed between 2006 to 2010, adding another 1,9 Tcf (53 Bcm) of capacity (see Figure 6.7). Priority is expected to be placed on the Northeast China pipeline networks, West-East II, Sichuan-East, cross-country pipelines and offshore pipelines.

Figure 6.7 Growth of natural gas transmission system



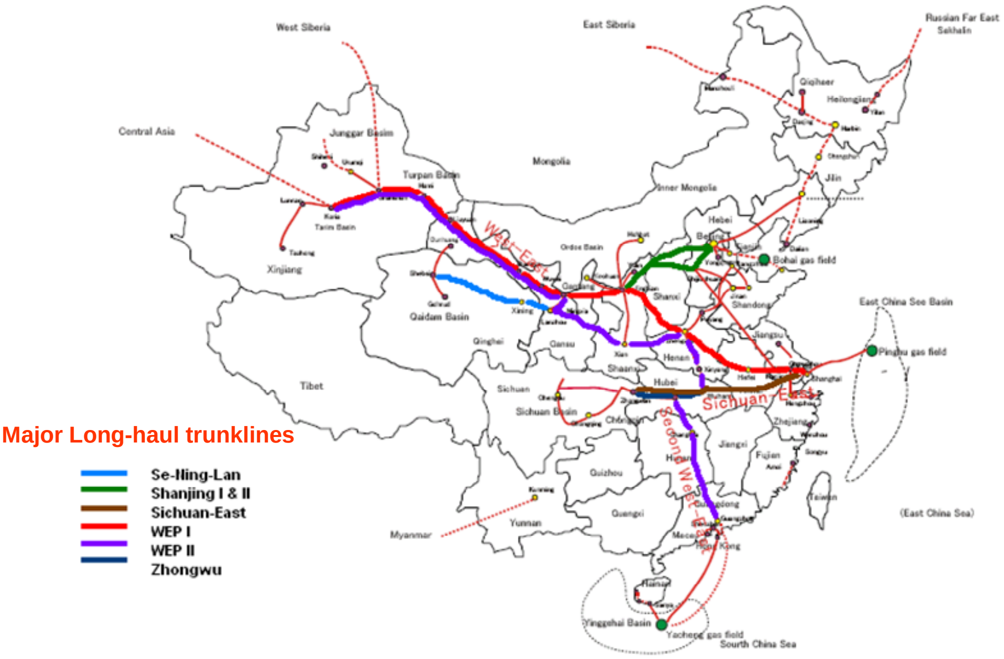
CAGR: Compound average growth rate

Sources: Natural Gas Transportation & Distribution Economics, Natural Gas Pricing and Its Application, China's Natural Gas Industry and Gas to Power Generation

Transmission

China's natural gas pipeline network is composed of a number of trunk pipelines connecting reserves in the west to consumption in the east.

Figure 6.8 Major long-haul trunklines



Source: China's natural gas industry and gas to power generation

Most of the pipelines are owned and operated by the NOCs – CNPC (PetroChina's parent company), Sinopec and CNOOC. While CNPC controls production and transmission in most of China, Sinopec does so in certain provinces and CNOOC does so for all gas that comes from offshore.

At the start of 2007, China's total trunk- and pipeline system exceeded 26,000 km.[20] The ownership percentages of the pipelines are as follows:

- CNPC/PetroChina – 70%
- Sinopec – 22%
- CNOOC – 6%

PetroChina's West-East pipeline, which began operations in January 2005, represents CNPC's main trunkline. The 2,500 mile pipeline originates in the Xinjiang region in the west, with the main branch line ending in Shanghai. The West-East pipeline has a capacity of 1.2 Bcf a day and contains numerous regional spurs along the main route, which has improved the interconnectedness of China's natural gas transport network.

The industry has undertaken efforts to upgrade the gas transportation infrastructure so that gas can be piped from remote basins to developed cities. Several main pipelines, such as the West-East pipeline, Shaan-Jing pipeline and Zhong-Wu pipeline, were constructed and put into operation as a result of these efforts.

By end of 2005, there were 29,000 km of natural gas pipelines with a transmission capacity of 2.1 Tcf (60.5 Bcm) per year. Of these, seven pipelines were longer than 700 km, adding up to 8,900 km, or a third of the total.

A national pipeline network is under development, with projects including long distance pipelines, pipelines connecting to those main pipelines, regional pipeline networks, and connection into existing and future LNG facilities.

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[20] Natural Gas markets in APP Countries with a Special Focus on India and China: Regulatory Issues, Cross-Border Trade, and Evolving LNG Contract Structures, East West Centre, July 2007.

Regional pipelines

With the completion of the trunkline initiatives, numerous regional pipelines and networks have been developed with more diversified ownership.

Figure 6.9 Major regional pipeline highlights

Source: China's natural gas industry and gas to power generation

Other plans for domestic pipelines are as set out in Figure 6.10.

Figure 6.10 Committed infrastructure projects in China

Pipeline/route	Length (km)	Capacity	Expected year
Yulin-Shandong	1,045	na	2008
Sichuan-West (Puguang-Shanghai)	1,702	12	2010
West-East II	7,700	30	2010

Source: China's natural gas industry and gas to power generation

Storage

China has a relatively short history of underground storage development and operation. All completed storage facilities were built and are owned by PetroChina.

Storage was not included in the project development plan of the first natural gas trunk pipeline, the Shaanxi-Beijing line. Storage facilities were built only when seasonal demand fluctuations became obvious in the major demand centres. The first significant storage project, the DaGang facility, began development in 1998 and was completed in 2000

As part of all new pipeline projects PetroChina now incorporates plans for gas storage to accommodate demand variability in consuming centres. The majority of storage projects were developed during the early 2000s to cater to the rapid demand increase and significant seasonal fluctuations of the Beijing area.

Underground storage facilities have now become an important part of the gas infrastructure. They have been developed in depleted gas fields, salt formations and in water aquifers, and have been built close to long-distance pipelines and big gas consumption cities to help moderate supply availability. By 2007, the total storage capacity was 106 Bcf (3 Bcm), accounting for only 6% of annual consumption.

A strategic imperative for storage development is being developed by PetroChina, and it is estimated that capacity will be more than doubled by 2010 and a further 315 Bcf added by 2020.

But even then, the total of 565 Bcf (16 Bcm) capacity will be less than 10% of anticipated annual consumption. Both government and industry recognise the need for storage capacity to reach levels seen in developed US and European markets, where it often accounts for 20% to 30% of annual consumption and is spread throughout the pipeline system.

Distribution

Gas distribution networks are divided into seven key regions:

- the South-West market centred around Chengdu and Chongqing
- the Jingjin market centred around Beijing and Tianjin
- the East China market based around Nanjing, Shanghai and Hangzhou
- the Shandong market centred at Qingdao and Jinan
- the North-East market at Changchun
- the South China market at Guanzhou and Konggong
- the Central China market at Wuhan, Xian and Zhengzhou.

The capacity of the distribution network as a whole still remains relatively underdeveloped – nationwide, there is about 90,000 km of distribution pipelines. However, many of these lines are used to deliver LPG or coal-bed methane (coal seam gas) rather than conventional gas. Many local gas distribution companies (also known as LDCs) tend to be run at a loss due to limited competition in local markets.[21] Gas distribution networks have been built by local companies and are regulated by city governments; however many cities in China do not have distribution networks.

It is expected that as demand for natural gas increases there will be further growth in these distribution systems and gas will become the favoured fuel in the domestic city gas market. Over the next 10 to 15 years the urbanisation is expected to increase from the current level of 43% to 55-60%, exacerbating the need for gas as a primary residential fuel.[22]

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[21] Global Insight Inc. 2008

[22] China's Energy Consumption Mix Optimises as Gas Demand Increases, Xinhua News Agency, Yang Liu, 26/11/2006

6.1.4 Gas markets

Wholesale market

There is only a limited wholesale market where wholesale prices are set by the government. It largely consists of bilaterally negotiated agreements between the NOCs and LDCs or large industrial users.

Due to the tightly regulated nature of the market and PetroChina's dominant position in upstream and midstream, the commercial terms have been developed with regard to PetroChina's logistical and commercial requirements.

All gas sales agreements are on a 'take or pay' basis. Contracts usually include clauses where the daily maximum supply is fixed, allowing only nominal daily variation to gas deliveries.

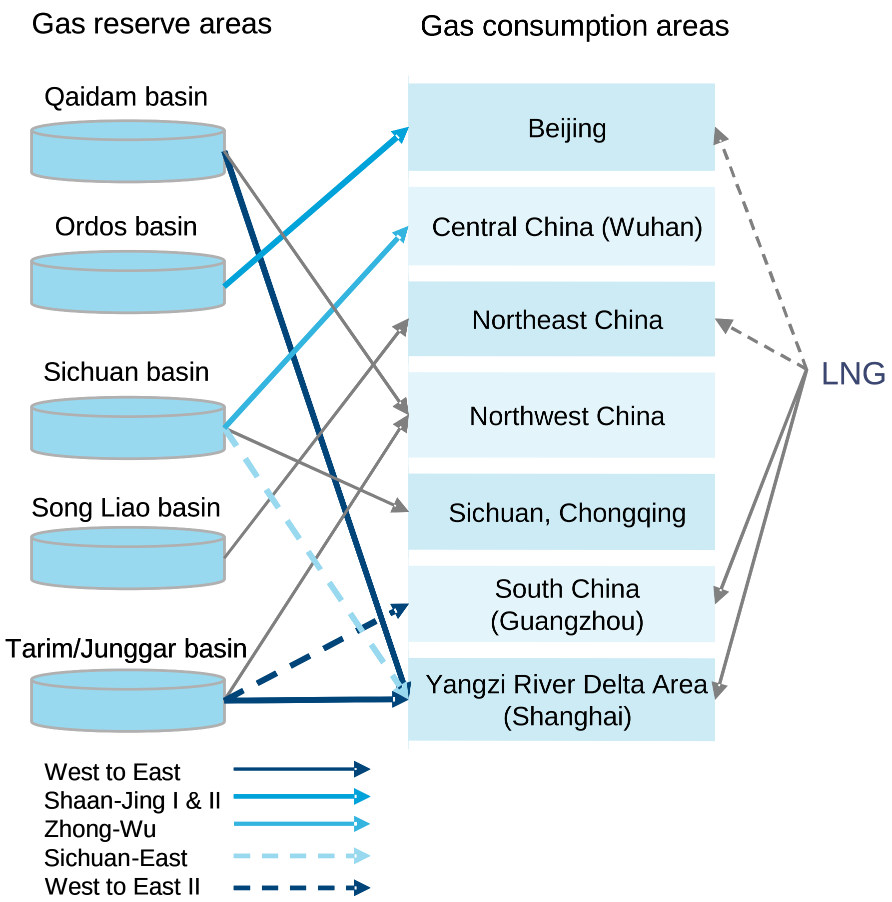
Midstream supply management

A key issue for China's wholesale market is midstream supply management. Customers are usually required to protect themselves from consumption and supply fluctuation. When demand exceeds supply, consumer usage takes priority over industrial usage. There are a number of high profile cases where industrial customers of PetroChina claimed major losses due to supply interruption.

Market players have started seeking approaches to achieve a more stable supply, and regions have been diversifying their supply sources to ensure energy security for gas.

PetroChina plans to build a more interconnected pipeline network to enable more flexibility to supply its customers. Also, storage is being increasingly used to provide gas supply buffers. PetroChina's strategic planning for storage requirements is moving towards a networked view. Staying close to consumption areas is generally the preferred approach.

Figure 6.11 Major coastal markets starting to multi-source

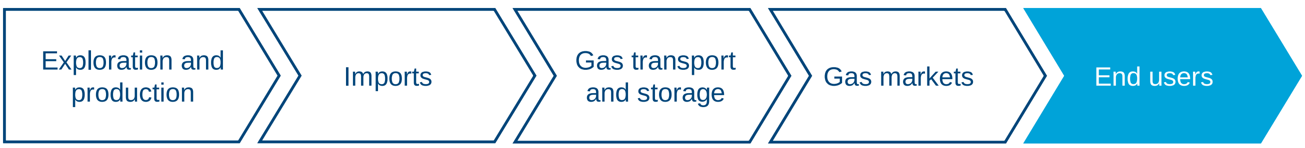


Source: China's natural gas industry and gas to power generation

Retail market

The retailing of natural gas is done by local city gas companies (LDCs) and provincial/city governments. Large industrial users and power plants may negotiate directly with the three state-owned suppliers which provide the gas to the citygate.[23]

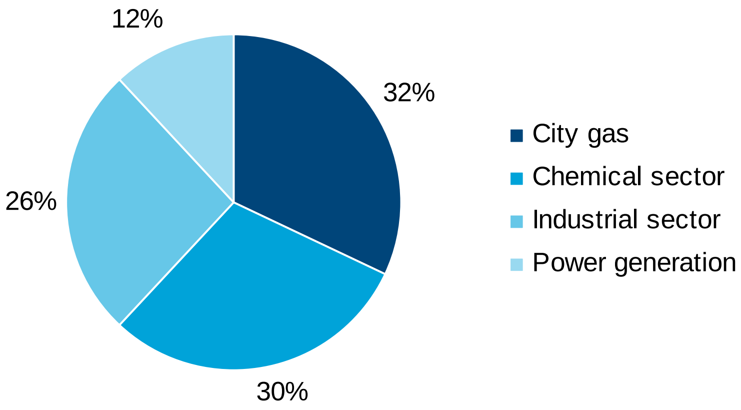
6.1.5 End users



[23] Natural Gas Markets in APP Countries with a Special Focus on India and China: Regulatory Issues, Cross-Border Trade, and Evolving LNG Contract Structures, East West Centre, July 2007

In 2004, natural gas only accounted for 3.1% of the energy supply mix, with most of the gas being used in the chemical and fertiliser industry.[24] According to IEA the demand for gas will grow significantly between 2004 and 2030 and may account for 5% of total primary energy demand by 2030.

Figure 6.12 Natural gas consumption by sector



Source: China's natural gas industry and gas to power generation

One of the demand growth areas for natural gas is its use in power generation. A large proportion of electricity is currently being consumed by industrial users, while electricity consumption within residential and commercial sectors supplied by city gas represents only 11.5% and 10% of the total demand, respectively. The residential electricity consumption is far behind that of developed countries, leaving significant potential for future growth given space-heating requirements in the north and west.

In 2006 the total capacity of gas-fired power stations reached 10,627 MW, accounting for 1.7% of the total installed generation capacity of 622,000 MW and 2.2% of thermal installed capacity. The government decided to de-commission all small thermal power stations with a capacity of 100 MW and below. These power stations represent a total generating capacity of 50 GW. It is expected that this capacity will be replaced by demand management and new developments, which is anticipated to include gas-fired generation.

There are plans for new gas-fired power stations to be commissioned in the next few years. The installed capacity of gas-fired power plants may reach 20 GW in 2010 and exceed 50 GW in 2020, by which time the proportion of natural gas power generation capacity is expected to be about 4%.[25]

6.2 Regulatory and legislative environment

6.2.1 Overview

Reform in the Chinese energy sector was slow prior to the 1990s but has accelerated since then and especially after China's entry into the WTO at the end of 2001.

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[24] China's Natural Gas Industry and Gas to Power Generation, The Institute of Energy Economics Japan, July 2007.

[25] IEA World Energy Outlook 2007 and PwC modelling.

There is no separate regulatory body for natural gas; it is regulated as part of a wider energy portfolio through a number of governing bodies. The main institutions that govern energy (including natural gas) reform in China include the National Energy Leading Group (NELG) (which is part of the Chinese cabinet and was established to develop high level energy policies), the National Development and Reform Commission (NDRC) (which is the peak body involved in economic planning and reform), the National Energy Office (NEO) (which was established by the NELG to represent it in the NDRC), the Bureau of Energy (who provides energy policy research and advice), the Ministry of Commerce and a number of other bodies such as Environmental Protection Administration, the Ministry of Public Security and the Ministry of Land and Resources.

The regulatory environment in China differs for various segments of the natural gas industry, with a number of laws regulating the industry. In December 2007, the Chinese Government released its draft energy law, to consolidate China's legislation governing the Oil and Gas sector. The draft energy law called for the setting up of a government controlled pricing regime and for energy companies to establish stockpiles for key fuels such as oil to address security of energy supply.

The current regulatory environment in the natural gas sector favours the four major state owned oil and gas companies namely – CNPC (and its subsidiary PetroChina), Sinopec and CNOOC Ltd., with less preference for private/foreign companies.

It has been six years since the publication by IEA of its report 'Developing China's Natural Gas Market 2002'. Many of the statements from this report regarding regulatory environment of China's natural gas market may still hold true today:

> "The legal and regulatory framework for the mid- and downstream is currently lacking. This creates uncertainties for investment and causes difficulties in conducting business related to gas transportation and distribution"
>
> "Lack of competition due to the monopoly structure of the gas industry and the lack of transparent and unified regulation were considered key constraining factors in China's gas market development"
>
> "Policy practices that currently prevail in China's gas industry are characterised by regional regulations and a project-by-project approach. For most large projects, such as LNG importing terminals or long-distance gas pipelines, policies are developed on a project-by-project approach. While this approach provides flexibility to deal with the specific characteristics of each project, it also creates a lot of confusion, involves many bureaucratic administrations, and provides many opportunities for government interventions in projects that could normally be undertaken following normal commercial practices. The project-by-project approach seems to be the preferred policy practice in China, but it may ultimately prove to be very costly both in time and money"

Incremental initiatives to further improve policy guidance for this sector include publication of 'China's Natural Gas Utilisation Policy' in September 2007 by NDRC, a reformed pipeline transmission tariff approach, and the listing of pipeline construction and operations as an 'encouraged' category for foreign investment. These initiatives offered the limited improved clarity and specificity that are required for market development.

NDRC issued 'China's Natural Gas Utilisation Policy' in September 2007, aiming to relieve the tension between natural gas supply and demand, optimise consumption structure, improve energy efficiency and cut pollutant emission. One of the key features of the Natural Gas Utilisation Policy is that it provides guidance to assure supply/demand balance through assigning responsibility for supply assurance measures. These measures include:

- For NDRC to control the overall demand of natural gas, aiming to maintain supply/demand balance.

- Provincial level government should carefully develop consumption plans based on actual capacity of gas supply to avoid supply/demand imbalances.
- Enhance the demand-side management, rationalise consumption, and assure supply security to residential, public facilities and key clients.
- Increase natural gas supply through central government encouragement of exploration and development activities along with the import of natural gas.
- Central government encouragement of construction of gas peak shaving facilities and the establishment of natural gas storage system for super cities to assure security of natural gas supply.
- Regulate the natural gas price reasonably. Improve the natural gas pricing mechanism by continuing the pricing system reform. Link the price level of natural gas with the price level of alternative energy resources, and leverage natural gas pricing to balance supply/demand.
- Stricter regulation on application of natural gas for power generation, chemical projects, and not allowing development of LNG projects using natural gas from large/middle scale gas fields as raw materials.
- In order to improve energy efficiency and promote environmental protection, China's central government encourages consumption of natural gas to replace high polluting coal and as an alternative to oil.

As a result of the measures above:

- The government is taking additional measures to increase its capacity of natural gas supply from the upstream market. However, it is also trying to rationalise the demand in the downstream market.
- More pipelines are expected to be built to boost the supply capacity and in the meantime, more natural gas storage is being encouraged to manage fluctuation of consumption and assure security of supply especially to the super cities.

However, a common understanding between regulators and the gas industry of how these developments are to be staged needs to be developed to reduce the potential impact on investment proposals of midstream assets.

6.2.2 Exploration and production

The Chinese government has granted rights to develop natural gas reserves to the three major state owned companies namely CNPC (and through CNPC to PetroChina), Sinopec and CNOOC Ltd. CNOOC has been provided exclusive rights to collaborate with foreign companies in exploring and developing offshore petroleum resources, while Sinopec and PetroChina have been provided exclusive rights to collaborate with foreign firms in exploring and developing onshore petroleum resources. State-owned companies normally enter into production sharing contracts with foreign companies to develop natural gas reserves.

The offshore area has been open to foreign investment since the 1970s. BP and CNOOC have joint venture arrangements in place to develop offshore gas fields. The onshore area has also been open to foreign investment since the 1980s; however the lack of consistent regulations has limited investment. Shell has a joint venture with PetroChina in the Changbei onshore gas field.

The main area where foreign investment is encouraged is coal bed methane (CBM). China has entered into contractual agreements with several companies to explore and develop its vast CBM resources.

Gas exploration licences are generally issued for a seven year period, with an option to extend for another two years. Exploration licences are also awarded based on the size of the gas field – the larger the field, the longer the tenure of the licence. Gas production is also dominated by the three state owned companies, who account for about 96% of total gas production. Production by these companies is concentrated in the Chuan-Yu Basin.

6.2.3 Imports and exports

Gas produced in China is consumed locally so policy and regulations in recent times have focused around imports. In particular, LNG imports are again dominated by the three state owned oil companies. In some instances the Government may grant import permits to local governments. In such instances the state owned companies have to work with local governments in setting up LNG terminals. All projects must be sanctioned by the NDRC.

6.2.4 Gas transportation

The major gas pipelines in China are owned by state oil companies, accounting for about 98% of the total pipeline network. Most of China's high pressure gas transportation pipelines were built in the 1960s and 1970s. In 2002, work began on the West-East Gas Pipeline (owned by PetroChina) with the first phase resulting in the construction of about 3,400 km of pipeline transporting gas from Xinjiang province in the west to cities in the east including Shanghai.

An entity constructing a gas transportation pipeline must first meet the environmental and necessary land-right requirements before commencing construction. There is no third party access regime in China that relates to gas transportation nor any specific law that governs interconnected/integrated pipelines.

Gas distribution networks are owned by local city gas companies, and regulated by local governments. These local companies are allowed to enter into joint venture agreements with other private/foreign companies.

6.2.5 Gas markets

Gas marketing is mainly done by city gas companies and local governments. Industrial users may negotiate directly with the three major state-owned oil companies.

Gas prices in China are regulated by the government and vary across the supply chain. Gas prices include ex-plant prices (wellhead prices plus purification fees), pipeline transmission fees and distribution charges. Ex-plant and transmission prices together form the city gate price. Large users generally pay the wholesale price (ex-plant plus the pipeline transmission fees) while smaller users pay an extra distribution charge. LNG prices include arrival and re-gasification fees, pipeline transmission fees and a retail distribution charge.

Gas pricing varies from region to region: for gas fields that were in place before 1990s, the regulated gas prices are lower, while for newer gas fields the regulated gas prices at the wellhead and city gate are higher. The NDRC however intends to lift the prices charged at older gas fields to those at the newer gas fields within three years.

The NDRC has introduced a price reform policy called 'new price for new line' under which companies can propose gas prices for pipeline projects constructed after 1995, and the NDRC can make adjustments and approve prices as necessary.

Supply management

To date, there has not been adequate regulatory guidance on midstream supply management, and regulators could potentially adopt a more proactive approach towards the natural gas sector.

With the gradual completion of the initial trunk pipeline network build-up, there are increasing challenges for regulators and operators to more effectively manage gas supply. Some of these initial challenges are beginning to be addressed, such as:

- Initial build-up of trunk pipeline network has connected supply in the west to consumption in the east and helped create a strong market for natural gas in China. However, challenges remain for China's natural gas supply management.
- Overall upstream gas supply is not sufficient to meet downstream demand.
- Pipelines supplying secondary regions and cities are insufficiently developed.
- Midstream two-part tariff structures have been improving in terms of commerciality but are still far from providing sufficient incentives for optimised downstream usage.
- Trading platforms to enable a more active and transparent market are not available.
- Competition among NOCs to build networks and the lack of clear third-party access guidance has led to certain non-optimal pipeline development.
- A strategic reserve for natural gas is still largely a subject that is discussed at a theoretical level and not on the regulator's near-term agenda.

The government is making continued efforts to secure cross-country upstream supply and to encourage more optimised natural gas usage by publishing related policies.

Policies that promote natural gas use:

- The government has set low natural gas prices for the fertiliser and industrial/household sectors (near the older gas fields) to encourage use.
- The government has accelerated the construction of gas transmission and distribution pipelines, and is on track to meet its 11th five-year plan target of 20,000 km of new natural gas pipelines by 2010 which will increase gas availability.
- The government recently removed the 6% import tariff for LNG, further encouraging LNG to help fill the demand/supply gap.

7 India

7.1 Overview – India’s gas market

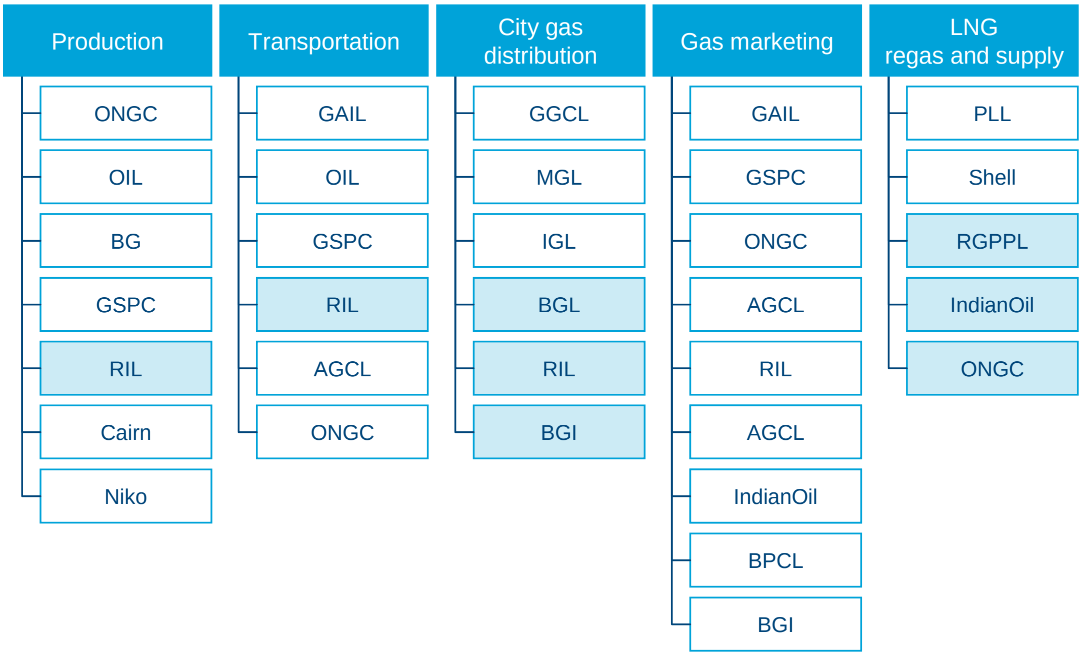
India now ranks fifth in the world in terms of overall energy consumption which is dominated by coal. In per capita terms, India's energy consumption is one of the lowest in the world. However, the rapidly increasing per capita use indicates a huge latent demand.

The importance of natural gas in India has significantly increased in the last decade due to its efficiency, cost effectiveness and environmental friendliness. India is the 22nd largest natural gas consumer in the world and it is expected that gas consumption will grow at an annual rate of 9.1% until 2020.[26]

India’s natural gas market contains all stages of the gas supply chain.

Figure 7.1 describes the gas market structure in India and the main players.

Figure 7.1 Gas market structure in India



Source: ABARE Research Report 2007

26 Natural Gas Markets in APP Countries with a Special Focus on India and China: Regulatory Issues, Cross-Border Trade, and Evolving LNG Contract Structures, East West Center, July 2007

7.1.1 *Exploration and production*

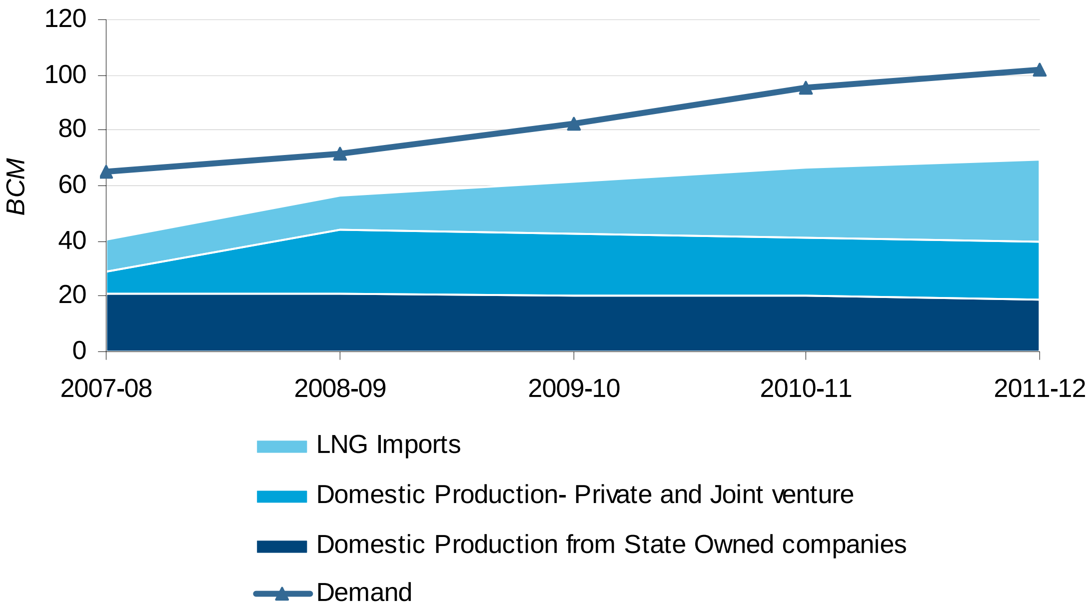
India's proven reserves of natural gas have grown steadily over the last two decades, and were estimated at 37.3 Tcf at the end of 2007.[27] Domestic production is dominated by offshore fields at this point in time. Substantial parts of India's territory remain unexplored, suggesting potential for growth in domestic gas reserves from future gas discoveries. In addition unconventional gas is being explored and there is an expectation that a CBM resource could be significant.

The main players in the sector are Oil and Natural Gas Corporation (ONGC) and Oil India Ltd (OIL), both government owned companies. Private businesses also participate in the industry with their own operations or through joint ventures with government owned companies.

Domestic natural gas production by the state owned enterprise ONGC is experiencing a downward trend, but at the same time significant discoveries are being made by private players like RIL and BG. The government is also encouraging the development of India's coal bed methane (CBM) resource base.

Figure 7.2 shows the total gas availability estimates and forecasts for India. LNG imports are likely to increase in the coming years in order to fill the gap between supply and demand.

Figure 7.2 LNG supply demand balance (BMC)



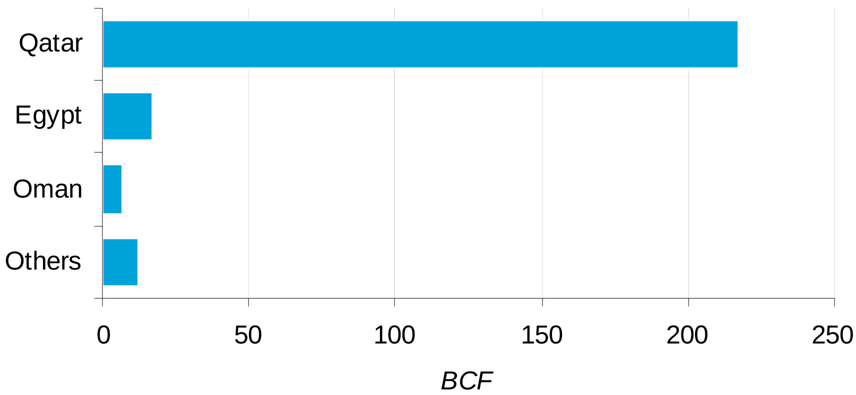
Source: Projections of the Ministry, Working group report 2006

27 BP Statistical Review of World Energy 2008. The Directorate General of Hydrocarbons Report 2006/07estimates proved and probable reserves of 58 TCF.

7.1.2 LNG imports

India started receiving LNG shipments in January 2004 with the start-up of the Dahej terminal in Gujarat state. Currently, India has two LNG re-gasification terminals, with LNG mainly being imported from the following countries:

Figure 7.3 India's main source of imports



It has also received smaller shipments from Australia, Iran, Algeria and Malaysia.

The Dahej LNG facility

This is owned and operated by Petronet LNG, a consortium of state-owned Indian companies and international investors. The terminal has the capacity to handle 5 million metric tons per year (Mt/y, or about 975 Bcf/y) of LNG imports. Petronet LNG is also building a second LNG-receiving terminal at Kochi, which is expected to have a capacity of 2.5 Mt/y (488 Bcf/y) when completed in 2009.

The Surat terminal

India's second LNG terminal started operations in April 2005 near Surat in Gujarat state. The facility is owned by Hazira LNG, a joint venture between Shell and Total. It has an initial throughput capacity of 2.5 Mt/y, with the option of expanding that to 5 Mt per year in the future.[28]

Plans are in place to build more receiving terminals with a capacity of over 23.75 Mt per year in the next five years.[29] Terminals under construction are Ratnagiri (formely Dabhol) which started in 2007 and Dahej, Gujarat (Expansion) which started in 2008 with a combined capacity of 10.5 Mt a year.

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28 EIA, Country Analysis Brief, India

29 Growth Strategy for GAIL (India) Limited in the Next 5 Years, GAIL (India) Ltd, May 2007

Pipeline imports

India is considered a very prospective pipeline gas import country in view of its proximity to large gas reserves in the Middle East.

There have been some government initiatives to import gas through transnational pipelines. The three most significant proposed pipelines are the Indo-Iran pipeline, the Turkmenistan-India pipeline and the Myanmar-Bangladesh-India pipeline.

However despite efforts made by the government, development has stalled due to geopolitical tensions in the region. In view of its proximity to India, the Myanmar project would have the lowest gestation period and is expected to start by 2009/10. Potential imports from this project are limited as the reserve base is smaller than that held by the countries in Central Asia and the Middle East.

7.1.3 Gas transport and storage

At this point in the time

A limited and somewhat constrained gas pipeline infrastructure currently exists. Several new pipeline projects are underway to increase gas deliverability capacity. There are no gas storage facilities in India. The Gas Authority of India Ltd (GAIL), a state-owned enterprise, holds the effective monopoly on natural gas transmission and distribution activities therefore dominating gas pipeline infrastructure.

Transmission

In December 2006, the Ministry of Petroleum and Natural Gas issued a policy allowing foreign investors, private domestic companies, and national oil companies to hold 100% equity stakes in pipeline projects. While GAIL's monopoly in natural gas transmission and distribution is not guaranteed by law, GAIL will continue to be the leading player in the sector because it owns most of the existing natural gas infrastructure. GAIL has a 78% market share in natural gas transmission and 70% market share in natural gas marketing.

Private players including British Gas, Gujarat State Petroleum Corporation Ltd and Adani Group have already established their networks in Mumbai and Gujarat.[30] Reliance has completed the construction of the 1,440 km pipeline project from Kakinada (Andhra Pradesh) to Baruch (Gujarat) to transport gas from Reliance's east-coast fields, and expects to start the pipeline shortly. Currently there is 6,800 km of natural gas high pressure trunk pipeline with a capacity to carry 10 Tcf of natural gas annually across the country.[31]

A series of planned and proposed pipeline projects are underway which are expected to add an additional 8,000 km of pipeline infrastructure to transport up to 750 Bcf per year by 2011.

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30 Natural Gas Markets in APP Countries with a Special Focus on India and China: Regulatory Issues, Cross-Border Trade, and Evolving LNG Contract Structures, East West Centre, July 2007.

31 GAIL (India) Ltd, Analyst Presentation, October 2007.

Distribution

Distribution of natural gas in India is mainly to industrial users. The city gas distribution network for most cities is poorly developed at this point in time, with networks only operating in Mumbai, Delhi, and in the state of Gujarat.

City gas distribution networks belong to companies such as Adani Group, BG and GAIL and cover only a tiny part of the population. The total number of natural gas customers in the residential sector is around 500,000, a very low number compared to the 75 million households using LPG, which is largely distributed through domestic gas cylinders.[32]

The government has initiated policies to promote the development of the distribution network infrastructure to serve the commercial and residential sectors. Infrastructure projects using compressed natural gas (CNG) for the transport sector are also being encouraged.

7.1.4 Gas markets

The gas market in India is developing and the marketing and sales is dominated by GAIL with almost 70% of the market share. There is a high degree of vertical integration in the Indian Market, with GAIL being the principal gas transmission, distribution and marketing company. Given this market structure, minimal competition for gas exists at this point in time.

Wholesale marketing

GAIL sells gas in bulk to anchor markets and also to a very large number of relatively smaller volume consumers. In the north-east of the country, Oil India Limited and Assam Gas Company Limited work in tandem to produce, transport and market gas, while GAIL handles the gas produced by the state owned ONGC.

Gas marketing is done by both public and private players. ONGC sells gas to GAIL and some other groups directly. Joint venture partners sell their gas as a consortium. The regulatory authority has proposed a 0% custom duty on LNG imports (currently 4%) which could make imports more attractive.

In India, gas trading is done predominantly through long-term contracts, and to a lesser extent through spot trades of LNG. The number of LNG cargoes becoming available to the spot market may increase in line with the growing demand for natural gas.

Pricing

Gas prices are determined by the source of the gas. The sources – and therefore pricing – for Indian gas can be broadly categorised as:

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[32] Natural Gas in India, ABARE, December 2007

1 An administered pricing mechanism (APM) price for gas supplied by government organisations (such as ONGC and Oil India Limited) to state-owned power and fertiliser companies.

2 A regulated price for gas supplied from joint venture partners (gas produced under NELP), calculated based on pricing clauses of the respective production sharing contracts.

3 Market-determined price for gas from private gas fields.

4 Market-determined price for gas produced from re-gasification of imported LNG.

Domestic production of gas by local public companies is priced lower than domestic gas produced by private and foreign companies. In the case of LNG, India has historically been reluctant to accept international LNG prices, which has prevented it from securing long-term supply contracts. However in recent years this has been changing and there have been discussions about linking domestic prices to reflect international prices. Domestic gas prices in India are expected to remain lower than those of LNG in the short term.

Retail marketing

The major gas marketing activity in India is done by GAIL, which sells gas in bulk to anchor markets and a large number of smaller volume consumers. Private companies like AGCL, GGCL, MGL and IGL are involved at the retail end of the gas marketing value chain.

In the LPG (bottled gas) sector, which is a major source for domestic use, the four oil marketing companies compete for market share. In the industrial and commercial sectors the choice of supplier is limited by the existing infrastructure. GAIL effectively holds around 70% of the retail market share but this has been reducing on account of new players like GSPCL and Shell.

Pricing

Retail gas pricing for households is largely a government policy directive and is dominated by a government owned monopoly which sells gas to households at a price below the actual cost. There are private players who have a minor market share, but price for their gas is higher.

7.1.5 End users

Natural gas consumption in India does not reflect the underlying demand, as consumption has largely been limited by the availability of natural gas supplies.[33] Natural gas usage has been growing by an average of 7.4% per year over the last 15 years and accounts for nearly 9% of primary energy consumption.[34]

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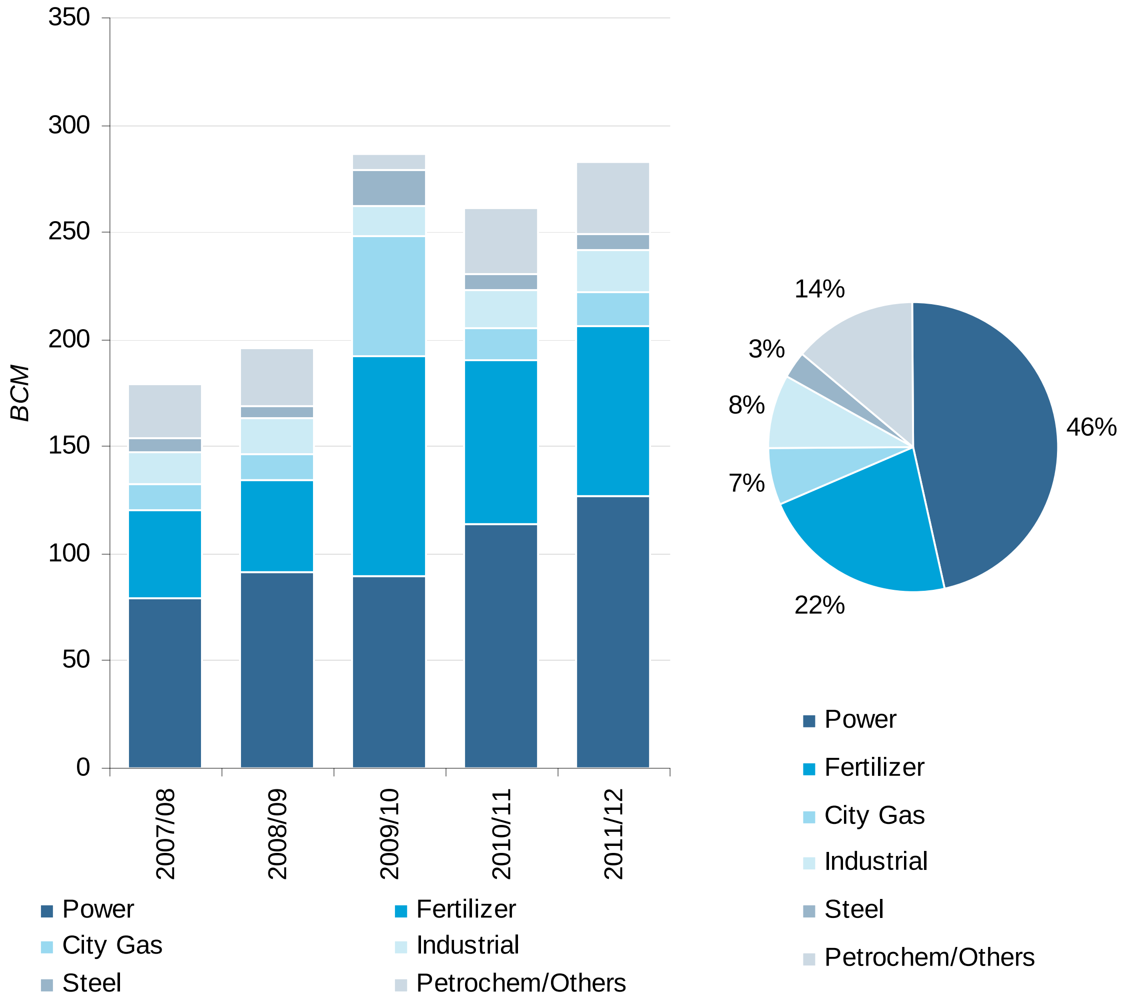
[33] Natural Gas in India, ABARE, December 2007

[34] PwC modelling and ABARE December 2007

The expansion in economic output, supported by a large and growing population with increasing living standards, has led to a strong demand for energy. The main natural gas consumers in India are the electricity generation and fertiliser industries, which account for more than two-thirds of natural gas use. The consumption of natural gas in other industries and in households is relatively small, although it is growing rapidly and is forecast to constitute 20% of total commercial energy supply by 2025.[35] This is displayed in Figure 7.4.

Figure 7.4 Gas consumption projections in India between 2007/08 and 2011/12



Source: Ministry of Petroleum & Natural Gas, Working group report 2006

Medium term growth is expected to come from the power and fertiliser sectors.

Until recently, all natural gas produced in India was allocated by the Ministry of Petroleum and Natural Gas. Allocation was based on sectoral priorities, gas availability and potential markets in particular regions. The priority consumers (electricity generation and fertiliser sectors) are still receiving most of the allocations, with some minor quantities being traded directly between consumers and suppliers.

35 Planning Commission India, Integrated Energy Policy 2005

Electricity generation accounts for more than 40% of India's natural gas consumption. Natural gas use by electricity utilities grew at an average rate of over 9% a year, from 134 Bcf (3.8 Bcm) in 1990 to 500 Bcf (14.2 Bcm) in 2005.[36] Existing gas-fired power plants in India do not operate at full capacity due to difficulties in securing natural gas supply.

The fertiliser sector is the second-largest consumer of natural gas in India, accounting for 25% of consumption in 2005. Demand from the fertiliser industry grew at an average annual rate of 2% from 1990, to reach 293 Bcf (8.3 Bcm) in 2005.[37] This increase reflects the high priority placed by the government on boosting agricultural production through greater fertiliser use.

Another major user is the automotive sector. Compressed natural gas (CNG) is used as an automotive fuel in a limited number of cities in India (mainly Delhi, Mumbai and Gujarat). The initially sluggish growth in demand from this sector has picked up as a result of recent directives by the Supreme Court of India to control air pollution caused by vehicular traffic. The directives included expansion of CNG infrastructure, conversion of buses, taxis and auto-rickshaws from liquid fuel to CNG, and allocation of natural gas to the transport sector in Delhi and Mumbai.[38]

In 2005/06 there were more than 300,000 CNG-powered vehicles on the roads, mainly in Delhi and Mumbai.

7.2 Regulatory and legislative environment

To encourage foreign and private sector participation, the Indian natural gas industry has been gradually moving from a government-controlled and owned business to one with an independent regulatory framework and a market-determined pricing climate.

Since the late 1990s, the industry has therefore been transforming itself from a regulated domestic oil and gas sector to be more market-driven, by allowing private participation in exploration and development of oil and gas fields, and by de-controlling prices of final products falling under the Administered Pricing Mechanism (APM).

The government has been moving towards a liberal and transparent foreign investment regime where some of the sectors have been opened up for foreign investment without any limit on the extent of foreign ownership.

Foreign Direct Investment (FDI) policy relating to the oil and gas sector has evolved over the years, to reflect the policy makers' intention to deregulate the sector and encourage competition.

7.2.1 Administration and oversight

The Ministry of Petroleum and Natural Gas (MoPNG) oversees the entire supply chain of activities in the oil industry: exploration and production of crude oil and natural gas; refining, distribution, and marketing of petroleum products and natural gas; and exports and imports of crude oil and petroleum products.

[36] Natural Gas in India, ABARE, December 2007

[37] Natural Gas in India, ABARE, December 2007

[38] Natural Gas in India, ABARE, December 2007

The Directorate General of Hydrocarbons (DGH) was set up in 1993 under the administrative control of the MoPNG, with the objective of ensuring proper oil and gas reservoir management practices, reviewing and monitoring exploratory programs, development plans for national oil companies and private companies, and monitoring production and optimum utilisation of gas fields.

Other organisations include the oil industry safety directorate, which develops standards and codes for safety and fire fighting, and the oil industry development board which provides financial and other assistance to foster development of the oil industry.

7.2.2 Exploration and production

Regulations for new gas exploration and production are set in the New Exploration and Licensing Policy (NELP), which permits private/foreign investments in exploration based on open-bidding for oil and gas blocks. This policy is regulated by MoPNG and DGH and involves companies bidding for blocks of work.

The role of DGH

DGH regulates the upstream oil and natural gas sector under the administrative control of MoPNG. DGH advises the government on issues related to the exploration and optimal exploitation of oil and gas, including advice regarding the offer of blocks for exploration to companies under NELP and coal bed methane lease and licence bidding process.

Besides its regulatory functions, DGH is responsible for ensuring proper reservoir management practices, for reviewing and monitoring field exploratory programs and development plans for national oil companies and private companies, and for monitoring production and optimum utilisation of oil and gas fields. This is to ensure that the companies who obtain exploration licenses conform to their committed time-tables for exploration and development activity.

7.2.3 Imports and exports

Any user is free to import LNG under the open general licence. The Foreign Trade Policy Law 2004-2009 states that the importation of natural gas is free and does not require any import-export licence. Customs duty is payable on LNG imports under the Customs Tariff Act 1975. The basic customs duty has been 4%.

Both public and private players are allowed to import LNG. However, exporting natural gas is barred as there is insufficient local supply to meet current demand. The main importer is Petronet LNG Ltd, which is 50% owned by the Indian government.

Any entity interested in establishing and operating LNG terminals must obtain registration with the PNGRB. In the absence of specific provisions within the PNGRB Act 2006, forthcoming detailed regulations will specify a framework for accessing or sourcing gas from LNG terminals.

Regulations for LNG plants have been framed to encourage overall growth and development of the sector. The import of natural gas as well as that of LNG is allowed without any restrictions. New terminal developers are free to decide on locations for LNG terminals, subject to environmental clearances and clearance from the PNGRB.

7.2.4 Regulatory framework – Downstream sector

The regulatory framework for the domestic natural gas sector is determined by the Petroleum Act 1934 and the Petroleum Rules 1976. Another relevant piece of legislation is the Petroleum and Minerals Pipelines (Acquisition of Right of User in Land) Act 1962, which provides for the right of use of land for laying pipelines for the transport of petroleum and minerals.

In 2006 the government cleared the way for the establishment of a regulator for the downstream oil and gas industry (excluding the E&P sector[39]), by enacting the Petroleum and Natural Gas Regulatory Board Act 2006 (the PNGRB Act 2006). The first of the policy directives released under this Act is expected to deal with marketing exclusivity for gas distribution companies and conditions for according infrastructure status to pipelines, which would result in fiscal concessions to the projects.

Petroleum and Natural Gas Regulatory Board Act, 2006

The PNGRB Act 2006 provides for the establishment of a Regulatory Board (the PNGRB) to regulate activities related to refining, processing, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas.

The Act empowers the PNGRB to:

- Implement regulations in the areas of:
  - marketing of natural gas
  - establishment and operation of LNG terminals
  - storage facilities for natural gas.
- Authorise entities to:
  - lay, build, operate or expand a common carrier or contract carrier, city or local natural gas distribution network
  - declare pipelines as ‘common carrier’ or ‘contract carrier’.
- Regulate access to pipelines (including open access) through enacting regulations.

7.2.5 Transportation

Transmission and distribution

Gas transmission and distribution (including the building of pipelines and related infrastructure) was formerly regulated by MoPNG but has now moved under the control of the new downstream regulator, PNGRB.

Until recently, gas transmission pipelines were exclusively built by GAIL but now private and foreign players are allowed to build them. The draft natural gas pipeline policy released in October 2006 empowers the PNGRB to be responsible for the selection of entities for building gas transmission and distribution networks through open competitive bidding. In 2008 the PNGRB released regulations for city gas operators and new pipeline investments.

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[39] The E&P sector continues to be regulated by the DGH

In a recent review of the distribution networks, existing players were not given market or network exclusivity as it would result in monopolies and hinder competition.

Access to pipeline infrastructure

Access arrangements are still developing in India and are subject to debate. The PNGRB is authorised to declare a pipeline as exclusive or non exclusive and to regulate or allow access to such pipeline or network.

For transmission pipelines, the regulator would evaluate the capacity of the pipeline against contracted/booked capacity by existing users, and allocate 33% of the excess capacity for open access based on published regulations. Any request for open access has to be responded to within three days by the pipeline owner. The transporters are also obliged to declare the excess available capacity on their website on a monthly basis.

For city gas distribution networks, the regulations enacted in March 2008 allows a period of exclusivity of three years for new pipelines and five years for existing pipelines if they have been operating for less than three years. Beyond the period of exclusivity, the owner of the pipeline is obligated to allow non-discriminatory open access. The regulator may also declare a pipeline for open access if there is found to be surplus capacity beyond the requirement of the current user. The draft regulations for tariff fixation of pipelines have also been issued by the regulatory board. While these regulations have been enacted recently, the evidence of actual implementation is not available in public domain. Nevertheless, the regulations have been designed with the purpose of enabling an open market in the gas sector.

7.2.6 Gas markets

Gas prices in India are a mixture of regulated and unregulated prices. Generally, prices are set by the market only when it comes from private gas fields or via LNG terminals. An organised spot market does not exist but there has been an increase in spot LNG trades, particularly through the Shell LNG terminal. However, this has not developed into a domestic gas market.

APM Gas

Most of the domestic gas produced by the Indian national oil companies and that produced under production sharing contracts is transported and distributed by GAIL. The state oil companies produce around 60% of the total gas used in India.

GAIL’s major customers obtain an allocation of gas due to them through the Ministry. Typically, such customers are power and fertiliser companies which are accorded priority under a ‘national interest’ basis. Gas is supplied to such customers under contracts (generally for up to five years) which set out the commercial terms and also contain general provisions for customer deposits, bank guarantees and standby or revolving letters of credit, and take-or-pay requirements.

The entire quantity of gas produced by the state entities ONGC and OIL is supplied to GAIL, which then provides most of the natural gas to the power and fertiliser units which have been accorded priority allocation. The producer price for this gas is currently determined by the tariff commission. The gas supplied through the state owned GAIL network to non-APM (ie non-fertiliser and power) consumers is based on the price at which GAIL buys it from joint venture producers at landfall point, subject to a ceiling.

Joint venture gas

Around 20% of the total gas supplies in the country originate from fields managed as joint ventures between state entities and private players. Gas produced by joint ventures is sold at negotiated prices under short-term contracts (3 to 5 years). The major buyers are GAIL, Gujarat Gas, Reliance Industries, Gujarat State Petroleum Corporation, etc.

New private fields and re-gasified LNG

The gas from the gas fields recently discovered by the private players can be priced as per market demand. The gas is expected to hit the market in 2009 through new transmission pipelines that are still under construction.

Petronet LNG has entered into a long-term sale/purchase agreement with Ras Laffan Liquefied Natural Gas Company Limited (Ras Gas) to supply 5 Mt per annum of LNG for 25 years. Petronet has also signed long-term gas sale/purchase agreements with GAIL, Indian Oil and BPCL for the supply of re-gasified LNG in the proportion of 60:30:10 for 25 years. These companies both use gas for internal purposes, and sell it to other end-users. The entire quantity of LNG after re-gasification into natural gas is transported using GAIL's pipeline network. Typically, gas sale contracts are for five to ten years.

The price of Petronet's LNG for 5 Mt pa was fixed until December 2008. From January 2009, the price will be linked to Far East pricing standards for LNG, the moving average of the JCC price.

There is no long-term agreement for meeting the LNG requirement of Shell's LNG terminal at Hazira; LNG cargoes are bought on the spot market. According to information available in the public domain, Shell LNG is sold in the Indian market at between US$7 and $12 per GJ.

In early 2008 the government mooted a new gas allocation policy which allocates all gas from the country's fields on a priority basis to the sectors of national interest. The policy has faced opposition from the market players and is currently under discussion. Figure 7.5 displays the direction of gas pricing reform.

Figure 7.5 Gas pricing reform direction

Past	Present	Future
100% government controlled Single price for all users and sources Cost plus basis	Government controlled in priority sectors • electricity • fertiliser • CNG/small consumers Market prices • private/joint ventures • regasified LNG	Free market pricing Competitive with alternative fuels Alignment with global trends

Source: ABARE Research report on LNG in India 2007.

8 Japan

8.1 Overview – Japan's gas market

Japan is the second largest economy in the world and is an industrial powerhouse with various industries contributing to the country's development and growth. However, it only produces domestically a small percentage of its overall energy needs and relies heavily on imports.

Japan has successfully diversified its energy imports from both a geographical and a fuel type perspective. Natural gas is primarily sourced through LNG and is an important component of Japan's energy mix (around 15%).

Although Japanese companies produce significant quantities of natural gas internationally, domestically Japan produces less than 4% of its natural gas needs. Japan imports more than 3 Tcf of LNG per annum, making it the largest importer in the world.[40]

Japan is a signatory of the Kyoto agreement and is actively pursuing opportunities to minimise its CO2 emissions intensity.

Although Japan is active in all stages of the supply chain, with vast international energy interests as displayed in Figure 8.1 Japan's supply chain below, its domestic production and exploration activities are minimal.

Figure 8.1 Japan's supply chain

8.1.1 Exploration and production

The proven natural gas reserves in Japan are 1.4 Tcf and annual production of around 104 Bcf accounts for roughly 3% of the total domestic consumption.[41] Most of the Japanese gas fields are co-located with oil fields. Japan's largest natural gas field is Yufutsu, which produces approximately 14.6 Bcf per annum. The Iwafune-Oki field, operated by Japex and Mitsubishi Gas Chemical, produces around 2.2 Bcf per annum.[42] These are located in Niigata, Chiba and Fukusima prefectures.

[40] EIA website and BP Statistical Review of World Energy 2008

[41] APEC Energy Overview 2007

[42] Energy Information Administration, Japan – Natural Gas

While the East China Sea bordering Japan is believed to hold substantial natural gas reserves, development has been delayed by disagreements between Japan and China over the demarcation of their maritime boundary. It has recently been announced that Japan and China have struck a deal to jointly develop gas fields in the East China Sea, which is a promising development.

So far it has been agreed for Japan to participate in China's CNOOC's Chunxiao gas development, which is expected to yield up to 35 Bcf of gas a year. A further agreement has been reached on the 50:50 joint development of an area near the Longjing/Asunaro area.[43]

Overseas activities

To help mitigate the country's shortfall of domestic natural gas resources, Japanese companies have gained access to natural gas resources by equity participation in LNG projects overseas.

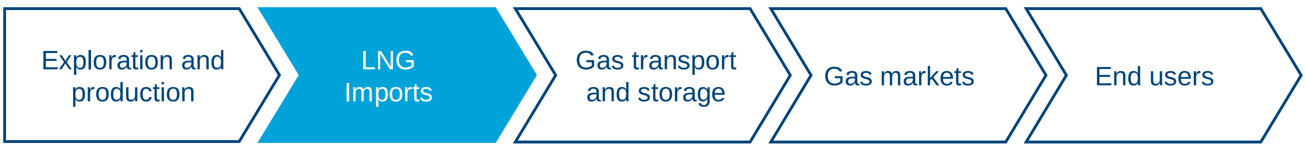
The main Japanese companies involved in overseas natural gas exploration and LNG production are INPEX, Nippon Oil, Mitsubishi, Mitsui & Co, Tokyo Gas and Osaka Gas.

One of the largest initiatives is Inpex's $20-billion Ichthys project in offshore Western Australia. The Sakhalin-II project in Russia which is being developed by Sakhalin Energy, with Gasprom (50%+1 share), Shell (27.5%-1share)and Japanese companies Mitsui (12.5%) and Mitsubishi (10%) holding participating stakes is another notable project. Japanese companies have also invested in several natural gas projects in Indonesia. In October 2006, Inpex announced that it had found substantial natural gas reserves in the Masela Block in the Timor Sea, in which Inpex holds a 100% stake.[44]

Private companies in Japan are involved in new pipeline projects, including the Sakhalin project that would take natural gas and oil to the southern tip of the island of Sakhalin. This oft-delayed project will create a new LNG source for delivery into Japan from March 2009.

The largest LNG supply agreements are held by Tokyo Gas, Osaka Gas, Toho Gas, and TEPCO, primarily with countries in Southeast Asia and the Middle East. Many of Japan's existing LNG contracts date from the 1970s and 1980s, when terms were less flexible and tied to prices for crude oil. With these contracts coming up for renewal, Japanese firms have been seeking more favourable terms including a weakening in the pricing link to crude oil. Many of these agreements are set to expire over the next decade, and it is unclear whether Japanese companies will be able to renew the contracts on more favourable terms.

8.1.2 LNG imports

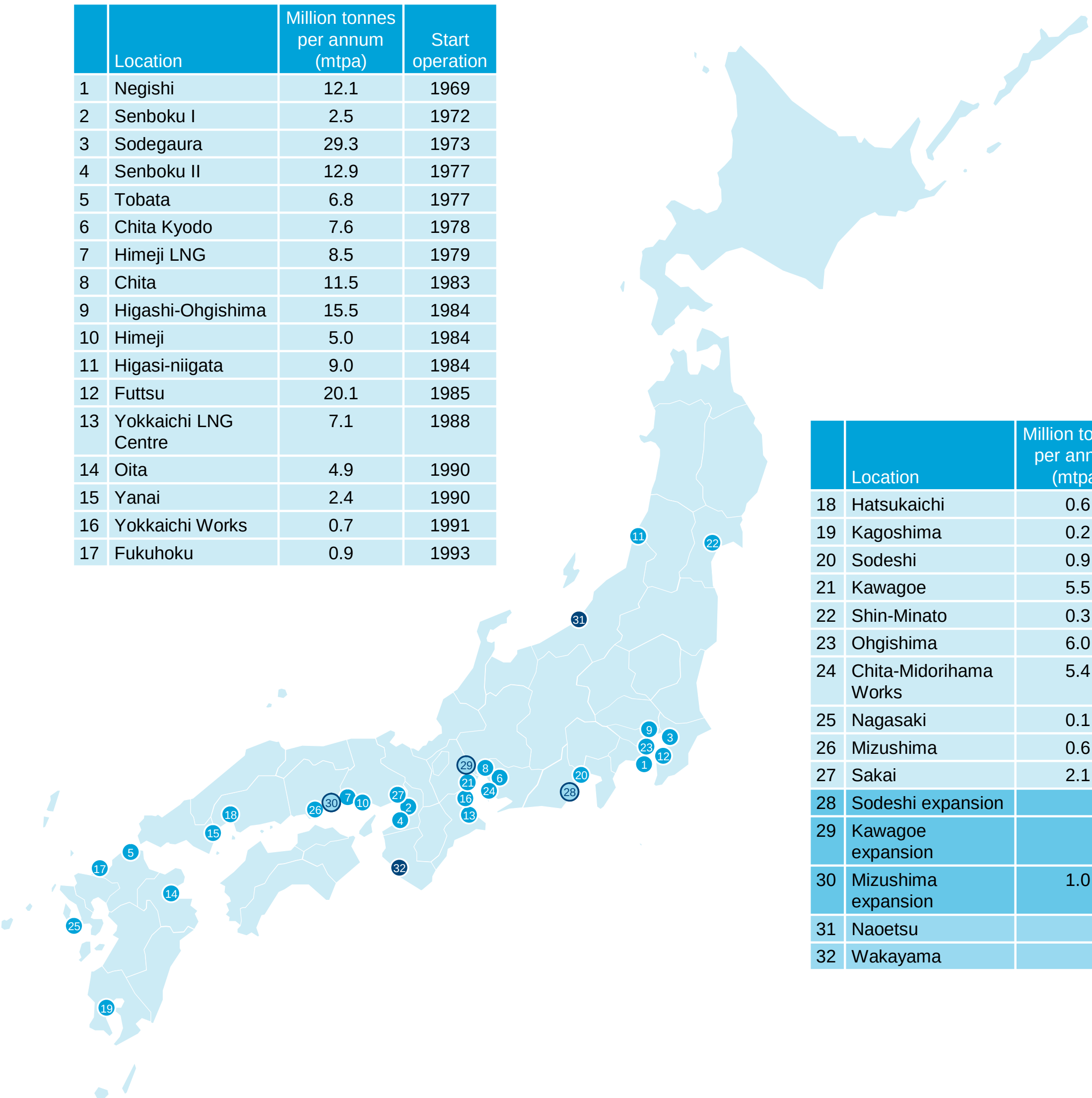


[43] Global Insights, East China Sea Accord Reached on Two Gas-Rich Areas; Maritime Borders an Issue for Another Day; 19/06/2008

[44] IEA Japan 2008 Review

Japan has been importing LNG since the 1960s and has now 27 operational LNG terminals; with six more planned or proposed to come on line starting in 2010. The country has an import capacity of over 178 Mt per year, the largest import capacity in the world.[45] The capacity represents 2.7 times the current level of imports.

Figure 8.2 Japan LNG terminal map



	Location	Million tonnes per annum (mtpa)	Start operation
1	Negishi	12.1	1969
2	Senboku I	2.5	1972
3	Sodegaura	29.3	1973
4	Senboku II	12.9	1977
5	Tobata	6.8	1977
6	Chita Kyodo	7.6	1978
7	Himeji LNG	8.5	1979
8	Chita	11.5	1983
9	Higashi-Ohgishima	15.5	1984
10	Himeji	5.0	1984
11	Higasi-niigata	9.0	1984
12	Futtsu	20.1	1985
13	Yokkaichi LNG Centre	7.1	1988
14	Oita	4.9	1990
15	Yanai	2.4	1990
16	Yokkaichi Works	0.7	1991
17	Fukuhoku	0.9	1993

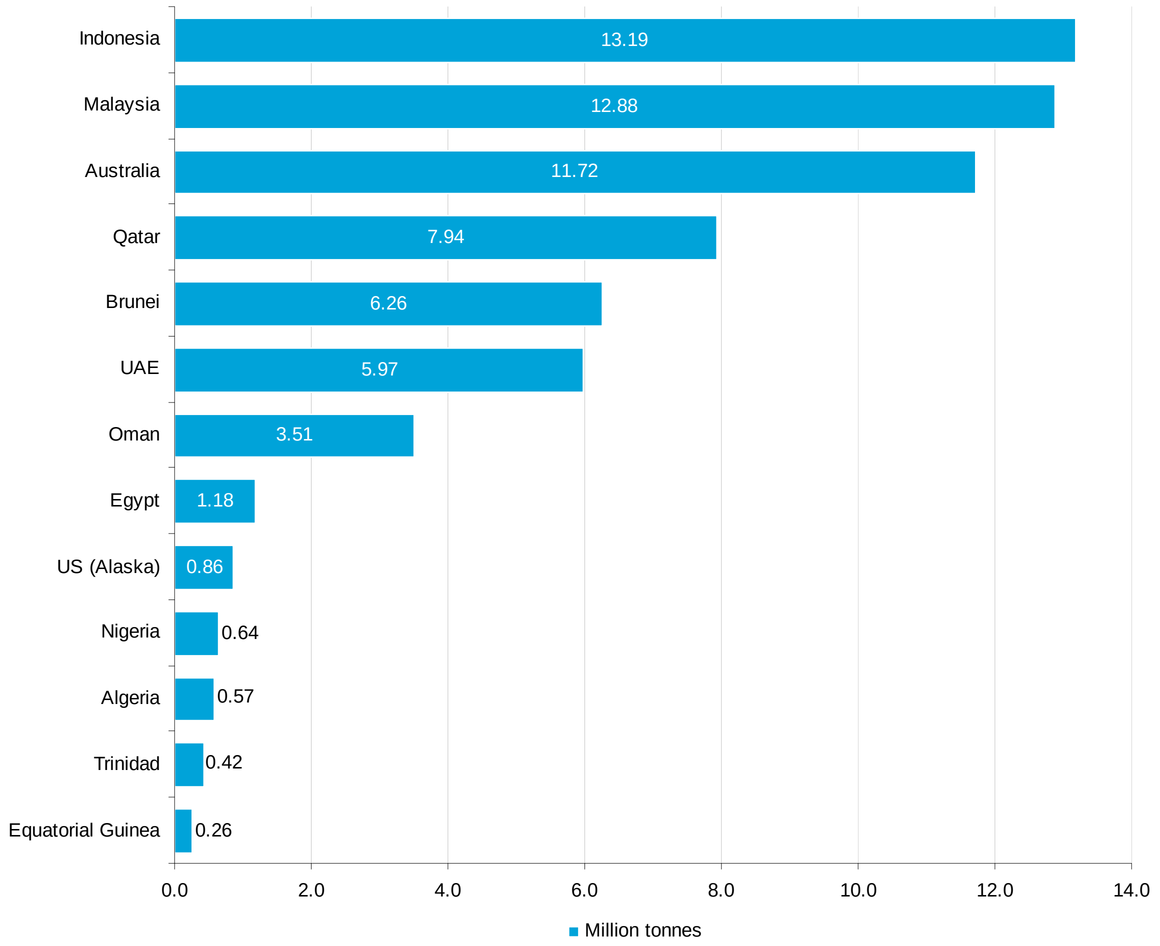
	Location	Million tonnes per annum (mtpa)	Start operation
18	Hatsukaichi	0.6	1996
19	Kagoshima	0.2	1996
20	Sodeshi	0.9	1996
21	Kawagoe	5.5	1997
22	Shin-Minato	0.3	1997
23	Ohgishima	6.0	1998
24	Chita-Midorihama Works	5.4	2001
25	Nagasaki	0.1	2003
26	Mizushima	0.6	2006
27	Sakai	2.1	2006
28	Sodeshi expansion		2010
29	Kawagoe expansion		2011
30	Mizushima expansion	1.0	2012
31	Naoetsu		2012
32	Wakayama		TBD

Source: Natural gas supply/demand trends in Asia-Pacific and Atlantic Markets (2006), The Institute of Energy Economics, September 2007

Japan imported 64.8 Mt (3.2 Tcf) of LNG in 2007.Imports are mainly sourced from eight countries: Indonesia, Malaysia, Australia, Qatar, Brunei, the United Arab Emirates, Oman and the United States. Reflecting efforts to diversify the supply sources, Russia will become ninth major supplier when exports from Sakhalin II LNG commence in the first half of 2009.

45 IEA Japan 2008 Review

Figure 8.3 LNG imports by country in 2007 (Mt)



Source: BP Statistical Review of World Energy 2008

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

The majority of natural gas is imported by Japan's electricity companies for power generation. These utilities, and some large industrial users, import their gas independently from the city gas industry. Electric utilities also participate in the gas market with gas they have imported. At the same time gas companies have also edged into the electricity market.

Many of Japan's LNG facilities are owned by power generation companies and gas distribution companies. These same companies own much of Japan's LNG tanker fleet. Some LNG terminals are owned individually by power utilities and gas suppliers while others are owned in co-operation through joint ventures.

8.1.3 *Gas transport and storage*

Exploration and production | LNG Imports | **Gas transport and storage** | Gas markets | End users

Transmission and distribution

The gas distribution grid extends throughout Japan, but the trunk line networks have developed separately and are not necessarily connected with each other. Each demand centre is largely autonomous to all other centres. Therefore, it is not surprising that the gas industry is vertically integrated in regards to transmission and distribution activities. Figure 8.4 displays the regional gas markets and their corresponding local utilities.

Figure 8.4 Map of regional markets for natural gas and main utilities

Source: International Energy Agency; Japan 2008 Review

Japan’s gas pipeline network is owned, operated and controlled by three different types of entities: regional gas, regional and electric utilities and domestic gas development companies. The bulk of the gas pipeline network is, however, controlled by the regional gas utilities.

Japan's main gas distribution companies are privately owned, act as geographical monopolies and are subject to considerable government regulation. Some smaller city gas companies are publicly owned. These tend to serve smaller towns and districts, and often procure gas indirectly through larger gas and power companies who have the main LNG supply contracts with overseas suppliers.

Japan has a limited natural gas pipeline transmission system with a very limited number of long distance high-pressure gas transmission networks. The total length of Japan's gas grid is 235,785 km, of which only 4,414 km are high-pressure pipelines.

The gas distribution network in Japan is well developed in 'densely inhabited districts' such as Kanto, Chubu, Kansai and Kyushu which serve the bulk of the economy's population; however, there are still some areas with a low density of population that remain without access to natural gas.

The lack of interconnection is a key infrastructure issue in Japan and is partly due to geographical constraints posed by the country's mountainous terrain and partly as a result of previous regulations that limited investment in the sector and restrictive land ownership practices.

Reforms in 1995 and 1999 have helped to open the sector to greater competition, and a number of new private companies have entered the industry since the reforms.

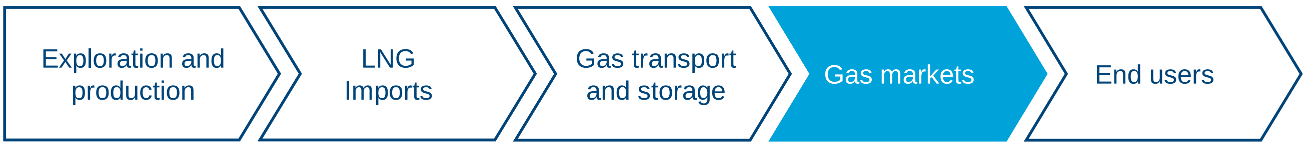
Storage

Japan has over 14 million cubic metres of LNG storage capacity (equivalent to 9 Bcm of natural gas) held at LNG re-gasification terminals. There is no underground storage of natural gas in its gaseous state as there is very limited availability of places that meet the necessary geotechnical conditions.

For storage purposes, Japan relies on existing inventories- the voluntary stocks of private companies held at LNG terminals- which are currently equivalent to 20 to 30 days of consumption.

The country takes advantage of diversity of supply sources, contract flexibility and spot market purchasing as a key means of maintaining supply security.

8.1.4 Gas markets



Wholesale market

There are regional wholesale markets in each region with two principal wholesale buyers of natural gas - the franchised gas utility and the franchised electric utility. The regional markets are split between the two buyers (according to end use), with electric utilities buying gas to fuel their gas-fired power plants and gas utilities buying gas to serve industrial, commercial and residential customers. The gas is purchased under long-term take-or-pay contracts from competing foreign suppliers through their LNG facilities.

Where previously, long-term supply contracts and the price stability that followed have been the key to a competitive position, Japan's major gas buyers have been taking smaller volumes, for shorter periods of time, than original contracts signed in the late 1980s and early 1990s specified. This trend indicates that supply diversity and contractual flexibility have been afforded greater importance as a means to maintain existing market shares and grow further in the context of Japan's mature gas market.

Some large electric utilities and a large steel maker import gas directly from competing foreign suppliers through their own LNG facilities.

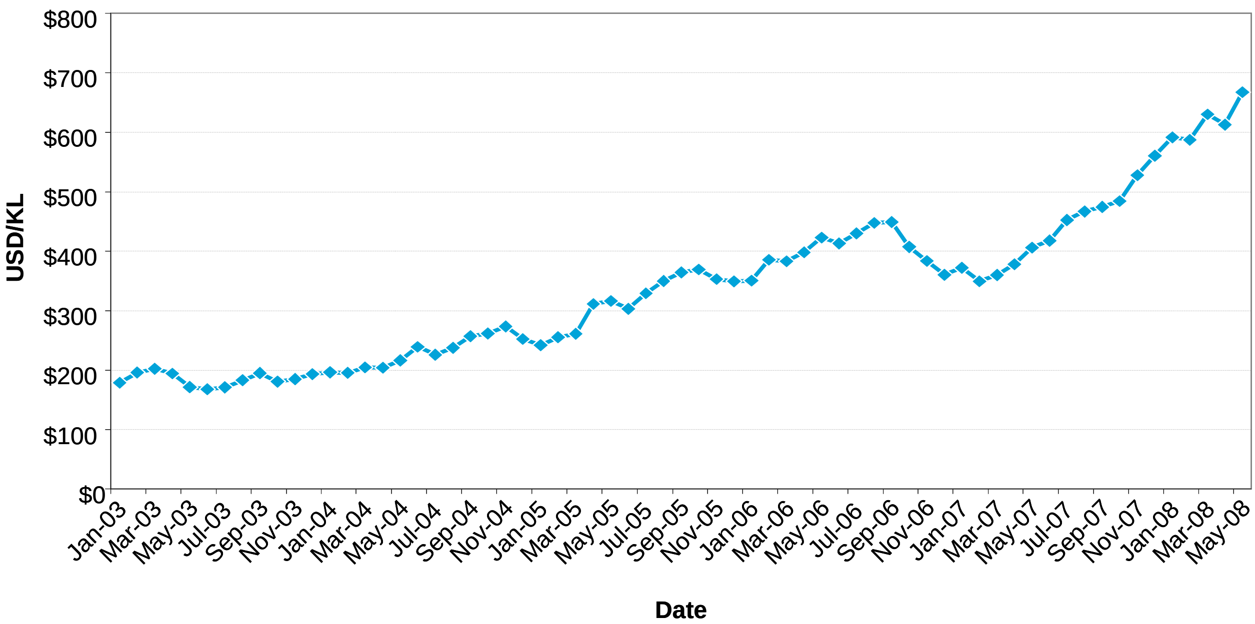
Pricing

The price for LNG contracts in Japan has predominantly been based on the formula linked to the “Japan Crude Cocktail” (JCC). Typically, the LNG price consists of a fixed base, plus a component that varies in constant ratio with the JCC price, plus an adjustment factor that varies with the degree that the JCC price falls above or below a “normal” band (also called S-curve).

Since most LNG contracts are for long-term supply according to this sort of formula, LNG prices in Japan have mainly reflected fluctuations in international oil prices rather than changes in competitive conditions.

As displayed on Figure 8.5 the JCC-price has been steadily rising over the past few years, up until the peak in the second quarter of 2008.

Figure 8.5 Japanese crude cocktail price index



Source: Publicly available data

Retail market

The city gas industry is fragmented into many vertically integrated regional companies. Tokyo Gas, Osaka Gas and Toho Gas dominate the market supplying residential and other urban customers. They jointly account for around 75% of gas sales by volume and supply approximately 65% of the customer base. Japan also has over 200 other small gas utilities occupying varying shares of market.

Currently there are over 200 city gas utilities supplying gas to over 28 million residential, commercial and industrial customers. There are four major gas retailers in the country with the combined market share of over 76% as at March 2007:

Figure 8.6 Key players in Japan's natural gas distribution sector

Company	Customer base	Market share (by volume)	Comments
Tokyo Gas	9.6 million	36%	Japan's leading gas company, serving Tokyo, Kanagawa, Saitama, Chiba, Ibaraki, Tochigi, Gunma, Yamanashi and Nagano
Osaka Gas	6.8 million	27%	Operations focus on the Kansai region.
Toho Gas	2.1 million	11%	Service area encompasses three prefectures: Aichi, Gifu, Mie.
Other	9.9 million	26%	Represents 35% of customer base and 26% of sales volume. More than 200 general gas utilities and 1,600 community gas utilities. The largest is Saibu gas with 2.4% market share.

Source: Global Insight Inc: Japan (2008) and IEA country analysis 2008.

Retail gas is tied to competitive fuel or netback pricing. This has discouraged investment in a wider gas network, beyond the immediate vicinity of LNG terminals and few connections exist between the different metropolitan networks.

Gas suppliers are regionally based but are able to supply gas outside their own area under certain conditions. Electricity companies, oil companies and other utilities can procure their own gas directly from foreign LNG producers and can then supply gas on to large-scale customers.

Deregulation of gas distribution started in early 2003, allowing competitive sales of gas to small-scale commercial customers and the public sector. The gas utility law was last amended in April 2007 allowing gas customers with demand of over 0.1 million cubic meters to choose their supplier which allowed over 10,000 city gas customers to choose their own retailer.[46]

Pricing

Natural gas prices for power generation are generally linked directly to the contracted price of LNG, since most power companies import their requirements directly.

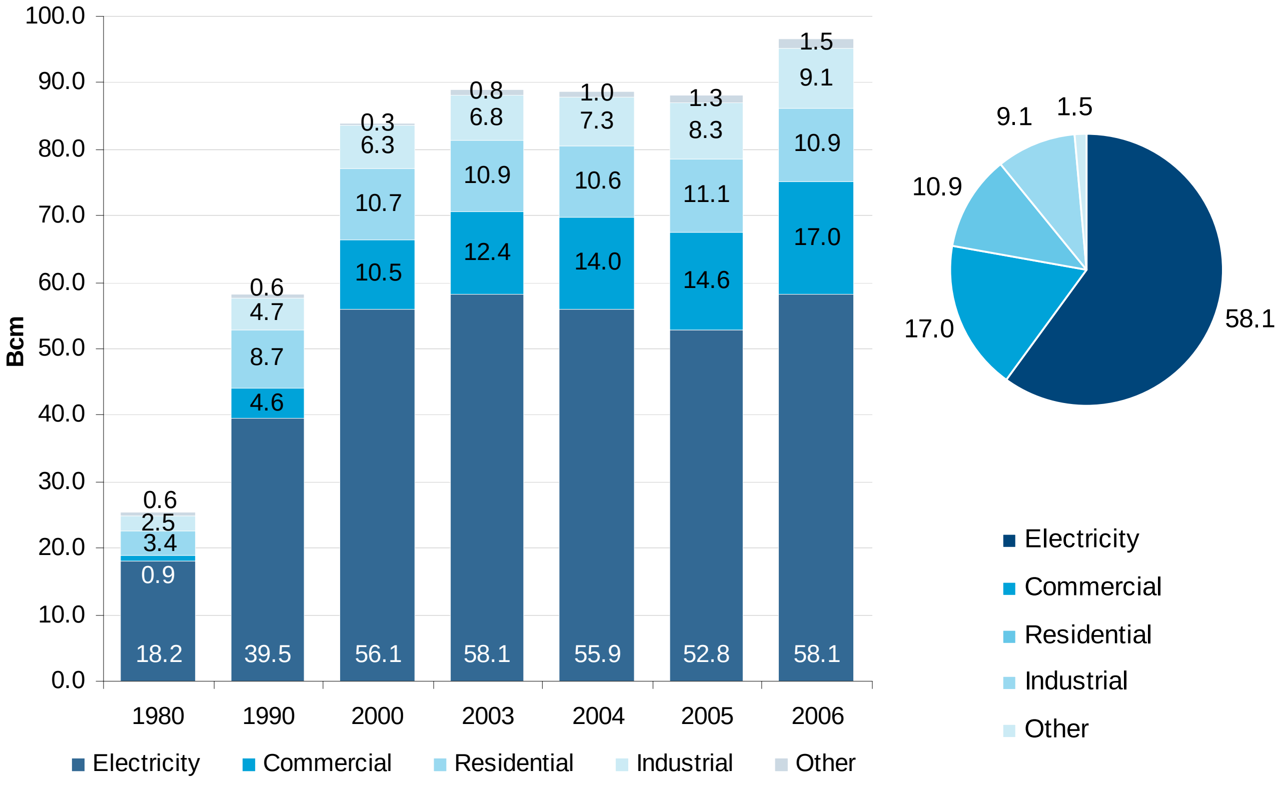
Tariffs for residential and industrial users are monitored by METI. The natural gas utilities law stipulates that prices must be determined on a cost basis and any increase requires government approval.

8.1.5 End users

46 APEC Energy Overview 2007

Japan’s fuel mix is reasonably well diversified, with four fuels making up most of the total. The share of natural gas within the primary energy mix in Japan is currently around 15% and is expected to remain at that level or marginally increase in the next ten years.[47]

Figure 8.7 Natural gas consumption by sector 1980-2006



Source: IEA Japan 2008 review

Most of the growth is expected to come from the industrial sector, switching from oil to gas, while the power sector and residential and commercial sectors are expected to only grow marginally.[48]

The power generation sector accounts for about 60% of total natural gas demand in Japan. This share has been declining since its peak in the 1980s.

The demand for gas from the residential sector represented 11% of the total demand for natural gas in 2006. In addition to conventional applications, gas demand in Japan is also being driven by the development of emerging technologies and next generation appliances.

Assisted by government subsidies and energy policy targeting air quality improvements and green house gas emission reduction targets, technologies including cogeneration, gas air conditioning and gas vehicle installations are gradually increasing in Japan.

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47 The Institute of Energy Economics 2006

48 Natural Gas Markets in APP Countries with a Special Focus on India and China: Regulatory Issues, Cross-Border Trade, and Evolving LNG Contract Structures, East West Centre, July 2007

City gas is a primary source of energy at 150 district heating and cooling plants located throughout Japan. These provide heating and cooling to high density urban development in a localised reticulated area.

8.2 Regulatory and legislative environment

The energy sector in Japan is primarily regulated by the Ministry of Economy, Trade and Industry (METI). METI grants licenses to the utilities, regulates electricity tariff and approves capital expenditure plans for the utilities. METI is also responsible for a large number of technical and safety regulations affecting the sector. Within METI, the Agency for Natural Resources and Energy (ANRE) regulates the energy sector. ANRE has various departments dealing with regulations in oil, gas, electricity and nuclear energy.

The main legislation governing the gas sector in Japan is the gas utility law.

8.2.1 LNG imports

There are no business restrictions on the construction of new LNG terminals, though it is necessary to meet the safety provisions of the laws relevant to LNG terminals, such as the gas business act and the electricity utilities industry law.

METI/Fair Trade Commission issued guidelines on appropriate gas trading, which were partially amended in August 2004, in order to ensure the neutrality and transparency of the third-party access system and make effective use of LNG terminals.

It seeks business operators that own or manage LNG terminals to create manuals for negotiations about the use of LNG terminals by third-party companies so as to clarify the preconditions and rules for such negotiations from the viewpoint of ensuring fair and effective competition.

The guidelines also stipulate that, from the same viewpoint, it is desirable that such business operators make sufficient information disclosure with regard to the capacity of LNG terminals, the current status of capacity utilisation and plans for future utilisation so as to enable an estimate of spare capacity.

8.2.2 Gas transportation

Amendments to the gas industry utilities law were carried out in 2004 to accord preferential treatment on pipeline construction as incentive for developing gas supply infrastructure.

To invigorate the gas market and promote competition the government is promoting the construction of pipeline networks and connections between independent networks. Financial aid, such as low-interest loans and tax benefits are provided for the construction of major pipelines.

As a result of the revision to the gas business act in 2003, general gas utilities and gas pipeline service providers are now required to keep separate accounts for transportation services and other relevant services, and to publicise the accounting data. This accounting system was introduced in order to encourage new entry by establishing fair and transparent accounting provisions.

Revisions to the gas business act in 2003 also relaxed requirements for conducting large-volume gas business, moving from a system where METI must approve the transaction to one where METI need only be notified. By the end of March 2007, 28 business operators had entered the large-volume gas supply market, sending 162 notifications to the government. These new entrants represent approximately 9.7% of all large-volume supply.

Third party access

The amended gas business act that came into force in 2004 requires all gas utilities to ensure third-party access (TPA) to their pipelines and established the category of gas pipe service provider business.

No general gas utility or gas pipeline service provider is allowed to refuse third-party access unless there is a special reason to justify the refusal, such as a transport capacity constraint.

8.2.3 Gas markets

Gas production facilities and equipment, as well as gas businesses are regulated by the gas business act, and the use of LNG outside the scope of the gas business is regulated by other relevant laws such as the electricity utilities industry law and the high-pressure gas safety law. The regulations are enforced by METI.

There is no secondary wholesale market in Japan. Trade is based on bilateral contracts and negotiated in the international markets. No regulation applies.

8.2.4 Retail

Reform and liberalisation of the gas sector began in 1995, when users with an annual contracted volume of 2 million cubic metres or more could contract for gas from parties other than their general gas utility. These days, the contestable retail market represents around 60% of the total gas market and full retail contestability is being discussed. Figure 8.8 displays the rollout of retail contestability for gas.

Figure 8.8 Market liberalisation for natural gas consumers

	Mar 1995	Nov 1999	Apr 2004	Apr 2007	
Major institutional and operational reforms implemented thus far in the expansion of liberalisation	• Establishment of large-volume supply system • Introduction of departmental balance settlement • Introduction of yardstick method • Introduction of material cost adjustment system	• Liberalisation of gas rates – Shift from the approval system to notification system in the case of reductions or other revisions of rates that are not detrimental to users interests • Liberalisation of wholesale supply system – Shift from the approval system to notification system	• Establishment of gas practice service business • Deregulation for large-volume supply – Shift from approval system to notification system • Abolition of notification system for wholesale supply		• In April 2007, the scope of deregulation was expanded to cover users with annual contracted volume of 100 000 m³ and over • Evaluation and verification of the liberalisation process will begin in the autumn of 2007 with the aim of reaching a timely conclusion on the issue of how to achieve complete deregulation
	• Development of the guidelines for handling transportation services	• Establishment of transmission service system by way of law for facilitating new market entries and ensuring transparency and fairness in transmission services – (only applicable to four major gas companies)	• Requiring that all general gas utilities and gas pipeline service providers formulate transportation service provision, provide notification thereof and publicise said provisions • Introduction of balance settlement for transportation services • Prohibition by law of use of information for unintended purposes, discriminatory treatment, etc	• Introduction of simple procedures for maintaining supply and demand balance • Development of transportation service provisions that cover low-pressure pipelines • Relaxing of rules on rate-setting for transportation services – Calculation of depreciation cost in accordance with actual use	

Source: IEA Japan 2008 review

9 Republic of Korea

9.1 Overview – Korea's gas market

The Republic of Korea (Korea) experienced tremendous economic growth over the last 25 years. Total primary energy supply has increased nine-fold since 1975 and doubled in the 10 years from 1992 to 2003. Growth has begun to slow, but Korea is still considered amongst the fastest growing Asian economies.

Korea is the sixth largest energy consumer in the APP (ahead of Australia) and the ninth largest energy consumer in the world, just behind France and ahead of the United Kingdom.

It's energy policy is focused on ensuring supply security through diversification of fuels, both in terms the type of fuel and where it is sourced from. It has successfully spread its gas supply sources across the Asia-Pacific and the Middle East enabling it to meet its rapidly growing energy demand during the high-economic growth years.

Korea ratified the Kyoto protocol in November 2002. Korea is not considered to be a developed Annex 1 country at present, and therefore does not have reduction targets for greenhouse gases.

Energy imports and energy mix

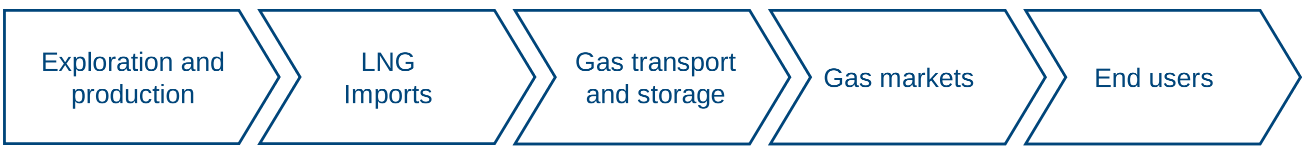
Korea is heavily dependent on other countries to meet its energy supply, and more than three quarters of the total primary energy supply (TPES) is imported. If uranium for nuclear energy generation was counted amongst the imports, then Korea would be almost entirely reliant on the rest of the world for its energy requirements.

Korea imports large amounts of crude oil (some of which is re-exported as refined products), and is the second largest importer of increasing LNG volumes. From the current consumption of about 1.3 Tcf (37 Bcm) of natural gas per annum, it imports almost all in the form of LNG and produces less than 2%.[49] Korea has no cross-border pipelines transporting gas into the country although it has expressed interest in several trans-national projects with Russia and China.

Oil makes up the greatest share of total energy consumption, though its share has been declining gradually from about 65% fifteen years ago to just under 50% today. This decline in percentage terms reflects faster growth in natural gas and nuclear energy over the period.

Supply chain

The focal components of the Korean gas supply chain are imports, transportation and marketing. Although Korea's natural gas market incorporates all stages of the supply chain, its production and exploration activities are minimal.



[49] 2007 consumption as per BP Statistical Review of World Energy 2008

9.1.1 Exploration and production

In 1998 Korea National Oil Company (KNOC) discovered Korea's first natural gas deposits at the offshore Donghae-1 field, which holds proven reserves of 200-250 Bcf. KNOC began producing natural gas from the field in 2004, and average production is approximately 18 Bcf per annum. While this find was significant for Korea, the field supplies less than 2% of the country's annual natural gas consumption.

KNOC followed up the initial find with the discovery of smaller natural gas reserves in 2004 and 2005. KNOC continues to explore offshore territories for natural gas deposits.

Overseas activities

Korean companies are actively involved in overseas exploration and production projects to obtain equity in oil and gas. In addition to KNOC's international activities, KOGAS formed the International Projects Group in 2001 to expand its overseas investments. KOGAS has invested in several foreign LNG projects to secure domestic gas supply, including a 5% equity stake in Oman LNG, a 5% stake in Qatar's Ras Laffan LNG Co. Ltd. and a 6% stake in Yemen LNG. In addition, KOGAS has invested in natural gas projects in Burma and Vietnam and is actively evaluating a range of other opportunities in the greater Asia-Pacific.[50]

9.1.2 LNG imports

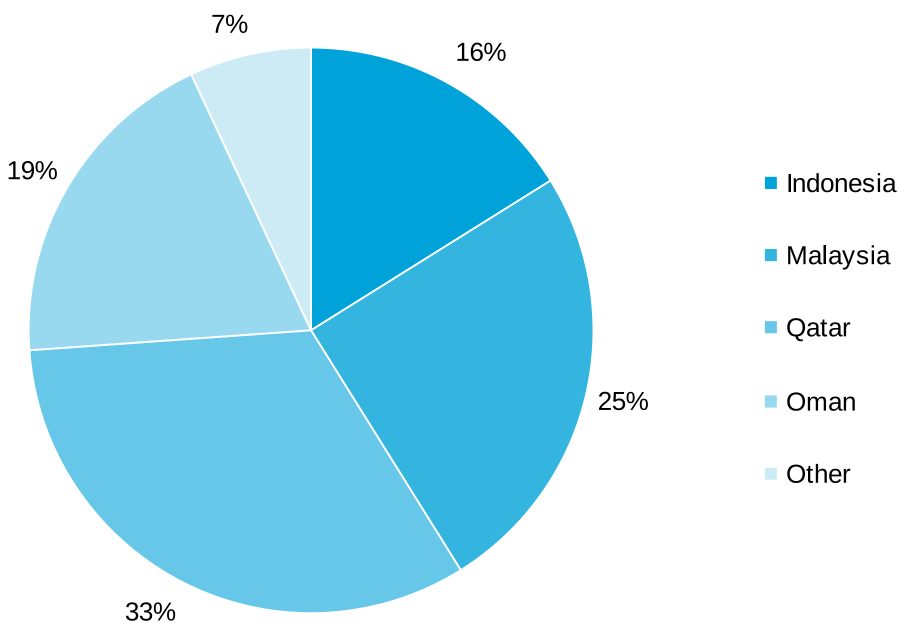
[50] EIA Country Analysis Brief June 2007

Korea currently relies on imported liquefied natural gas (LNG) for most of its natural gas requirements. LNG imports increased by an average of 10% per year during the five year period ending in 2005, but analysts and government forecasts suggest that this growth rate will significantly reduce.

Almost all imports are through the government owned Korea Gas Company (KOGAS). In the last three years, private firms with large gas demand have been allowed to import through independent contracts and Posco (the only private LNG terminal infrastructure owner) is one of a limited number of companies to have entered into non-KOGAS long term LNG contracts.

Korea imported 25 Mt in 2007. Figure 9.1 illustrates Korea's main sources of LNG. Supplier and geographical diversity is key to ensuring uninterrupted supply of natural gas and LNG, particularly for electricity generation and industrial use.

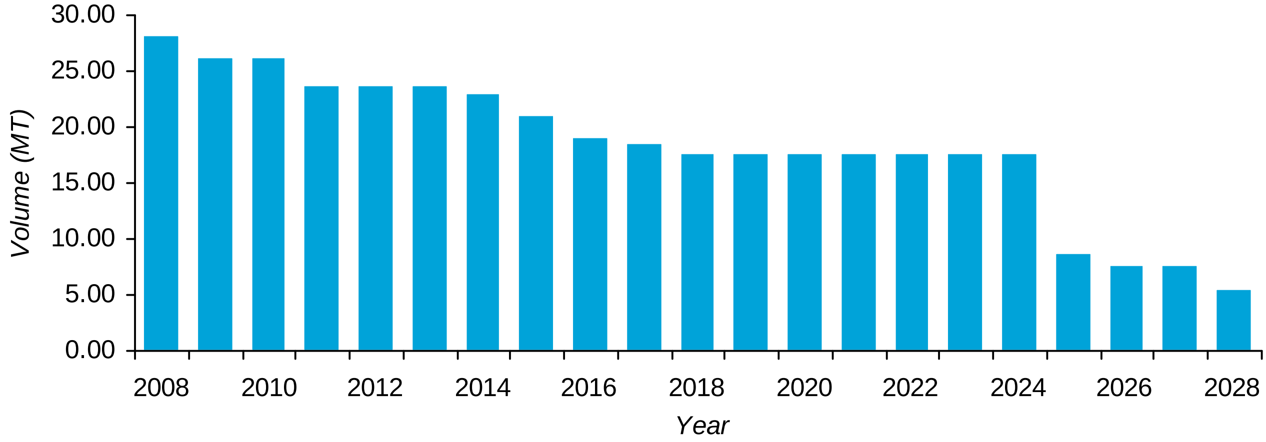
Figure 9.1 Korean LNG imports in 2007



Source: IEA

In addition to imports from Qatar, Oman, Indonesia and Malaysia, Korea also receives occasional cargoes from other countries including Australia, Brunei, Egypt, Nigeria and Algeria. Imports from Russia will commence in 2009.

Figure 9.2 Known contracted gas imports into Korea



Source: Compiled by PwC from public information

The two largest known supply contracts are with Qatar and Oman for 4.8 Mt and 4.0 Mt respectively, both entered into for 25 years and ending in 2024. In November 2007, KOGAS announced that it had entered into a Memorandum of Understanding (MOU) with the government of Sultanate of Oman for up to 2 Mt per annum of additional LNG. This will further contribute to long term stability of supply.

Import infrastructure

Korea's total import capacity is 75 Mt (104 Bcm) per annum, which is three times the actual import volume in 2007. KOGAS operates three re-gasification terminals (Pyeong Taek, Inchon, Tong Yeong) with a combined capacity representing three quarters of Korea's total import capacity. Pohang Iron and Steel Corporation (Posco) and Japan's Mitsubishi started commercial operations at the fourth LNG import terminal which is located at Gwangyang in July 2005. The plant is the country's first privately owned LNG receiving facility and has an annual capacity of 17.7 Mt (24 Bcm).

Figure 9.3 provides an overview of where key LNG infrastructure is located.

Figure 9.3 Map of natural gas infrastructure

	Operator	Terminal	Capacity BCM/annum
1	Posco	Gwangyang	24.3
2	KOGAS	Pyeong Taek	26.1
3	KOGAS	Inchon	37.9
4	KOGAS	Tong Yeong	15.3

9.1.3 Gas transport and storage

Transmission

KOGAS is the monopoly owner/operator of the gas transmission network. The 2,500 km transmission network provides gas to 75 cities and regions. KOGAS is also a primary importer and a wholesaler of natural gas which it sells to the city gas companies and to power stations.

The total distribution system extends more than 24,000 km throughout the country and about two thirds of the population has access to a gas connection. The gas trunk lines connect the distribution system to the three LNG receiving terminals owned by KOGAS. The domestic infrastructure network is still being expanded, but at a slower rate than in the past since a high proportion of customers in the main population centres are already connected.

Storage

At the start of 2005, Korea had 33 storage tanks above ground with a capacity of 1.88 Mt of LNG. This storage system is equivalent to 8.8% of total annual demand. The government has plans to increase the storage capacity to 12.7% of annual demand by 2017 to help ensure security of supply and to manage seasonality of gas consumption.

In addition to the storage facilities operated by KOGAS, Posco's re-gasification terminal at Gwangyang has a storage capacity of 1.7 Mt.

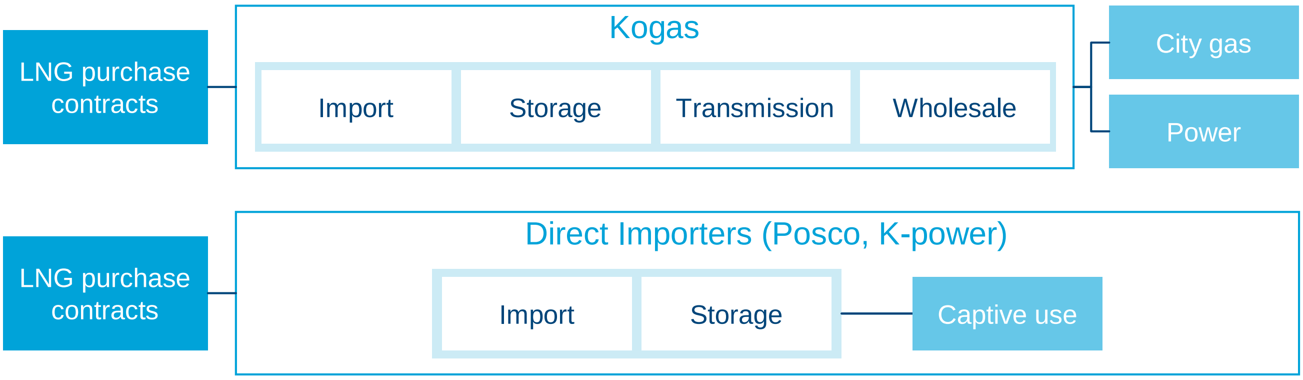
9.1.4 Gas markets

Wholesale and retail markets

Distribution and sale of natural gas (from LNG provided by KOGAS) is carried out by 33 local city gas companies, each of which has exclusive rights to operate in a defined urban area. Small amounts of gas have also been sold directly by KOGAS to large industrial consumers near its facilities.

The Oil Business Law was amended in 1998 to allow imports by big customers for captive use. As a result of this legislation Posco commenced imports in 2005 and K-power in 2006. The activities in which KOGAS and big customers can now operate is displayed in Figure 9.4.

Figure 9.4 Import and storage for captive use



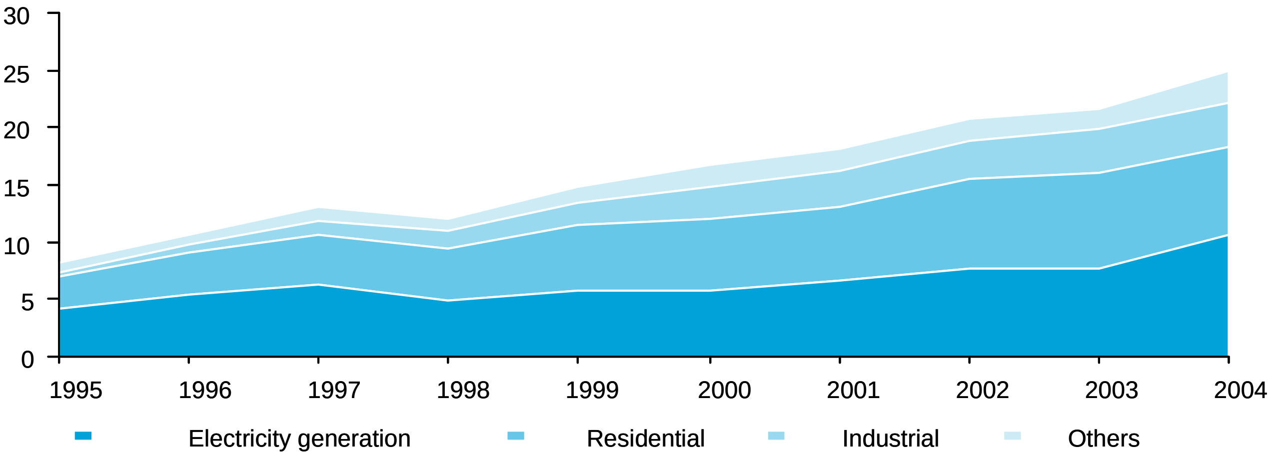
Source: Kogas

The 33 local city gas companies supply gas to industries and households within their defined geographic territories. All city gas companies source gas from KOGAS and retail to customers at prices that are fixed by the local government in the provinces. Therefore, retail prices may not always reflect the price of the commodity.

9.1.5 End users

Gas consumption has increased at an impressive rate since LNG was introduced to the energy mix in the late 1980's. Electricity generation and the residential sector are now the largest consumers in Korea as displayed in Figure 9.5.

Figure 9.5 Consumption of natural gas by sector in Korea



Source: Energy balance of OECD Countries, IEA/OECD Paris 2006.

Further growth is projected for residential and commercial and industrial sectors. Demand for gas in the commercial and residential sector is strongly seasonal in line with requirements for space heating in winter. The city gas sector (including residential, commercial and industrial customers) has a seasonal turn-down-ratio of four, meaning that four times as much gas is consumed in the peak winter month than in the lowest summer month. Within the city gas sector, residential gas use has a turn-down-ratio of almost 10.[51]

Coal still plays an important role in Korea's electricity generation and accounts for 37% of electricity generation. Coal is also used in large quantities in steel production and by cement companies.

9.2 Regulatory and legislative environment

9.2.1 Overview

The Ministry of Commerce, Industry and Energy (MOCIE) is the primary government body for energy policy. MOCIE is responsible for policy planning, supervision of the industrial sector, climate change matters and price controls. The Energy Policy Office within MOCIE handles the majority of energy matters.

Korea does not have a regulator for the natural gas sector. Regulations are implemented by the MOCIE at the national level and by the various local governments at the provincial level. Currently, the Fair Trade Commission (FTC) handles general business oversight in the sector in the absence of a dedicated regulator.

Legal framework

The Korea Gas Corporation Act and the City Gas Business Act were enacted in 1983. At the same time the Korea Gas Corporation (KOGAS) was established as a state-owned monopoly that would control all aspects of the wholesale natural gas industry from sourcing to distribution. Under the terms of the Korea Gas Corporation Act, MOCIE provides administrative guidance and supervision for KOGAS.

Natural gas regulations

The Korean government developed a plan (The Basic Plan for Restructuring the Gas Industry) for liberalising the natural gas market and this was enacted as legislation in 2001. However, the reform plan was subsequently postponed.

Negative experiences with deregulation in the United States (including extreme price volatility, blackouts and bankrupt utilities) have been sited as the main reasons for not proceeding with market reform. According to revised plans for liberalisation that are being discussed, KOGAS will remain a state-owned company, and the government is working on revised policies to encourage new entry from private companies.

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51 IEA – The Republic of Korea, 2006 review

Electricity regulations

KOREC (Korea Electricity Commission) was established in 2001 to regulate generation, transmission, distribution, independent power producers (IPPs), generation companies and the Korea Power Exchange (KPX).

KOREC is an independent unit within MOCIE. Its nine commissioners are appointed by the President on the recommendation of MOCIE, and they cannot be dismissed except in cases of dereliction of duty or imprisonment. Final decisions are made by MOCIE following the rulings or deliberations of KOREC. So far MOCIE's minister has not overruled the decisions of KOREC.[52]

9.2.2 Exploration and production

In the upstream gas exploration sector, KNOC is the primary company involved in exploration, development and production of natural gas.

KOGAS has plans to become a fully-integrated energy company and is increasingly involved in upstream activities overseas. KOGAS is 27% owned by the government, 25% owned by the state-controlled Korea Electric Power Corporation (KEPCO), with the remaining equity split among local government and institutional investors.

9.2.3 Imports and exports

Under the original restructuring plan, KOGAS was to be unbundled into three separate import companies. As a means to reduce its market share to spur gas market competition, KOGAS was prohibited from signing more long-term contracts so that other companies could enter the market. In addition, the plan stipulated that open access would be implemented on LNG receiving terminals and pipelines.

Current status: KOGAS' monopoly has been relaxed to the extent that the government has allowed certain large users to import gas for their own use.

9.2.4 Gas transmission and distribution

As set out in the original reform plan, KOGAS was to provide open and non-discriminatory access to all of its LNG, pipeline and storage facilities from 2003. All competing suppliers were to be able to use these facilities to import gas and bring it to their large customers who could access the gas transmission grid.

To ensure that KOGAS treated competing suppliers in a non-discriminatory fashion, it was to be divested of most functions that do not relate to natural gas transportation. KOGAS was to be a purely network infrastructure company and retain its LNG, pipeline and storage facilities but no supply function.

At a later stage, the open access regime was to be extended to gas distribution. The regional distribution monopolies were to be unbundled into separate distribution and retail supply companies. It was foreseen that competing suppliers would then be able to use the distribution grid on non-discriminatory terms to bring gas to small residential and commercial customers.

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[52] IEA The Republic of Korea 2006 review

Current status: Large users that import gas for captive use can use KOGAS' pipeline through negotiated third party access. The government is working to establish regulated third party access on natural gas pipelines. This alternative concept would be more effective in terms of developing competitive markets.

9.2.5 Gas markets

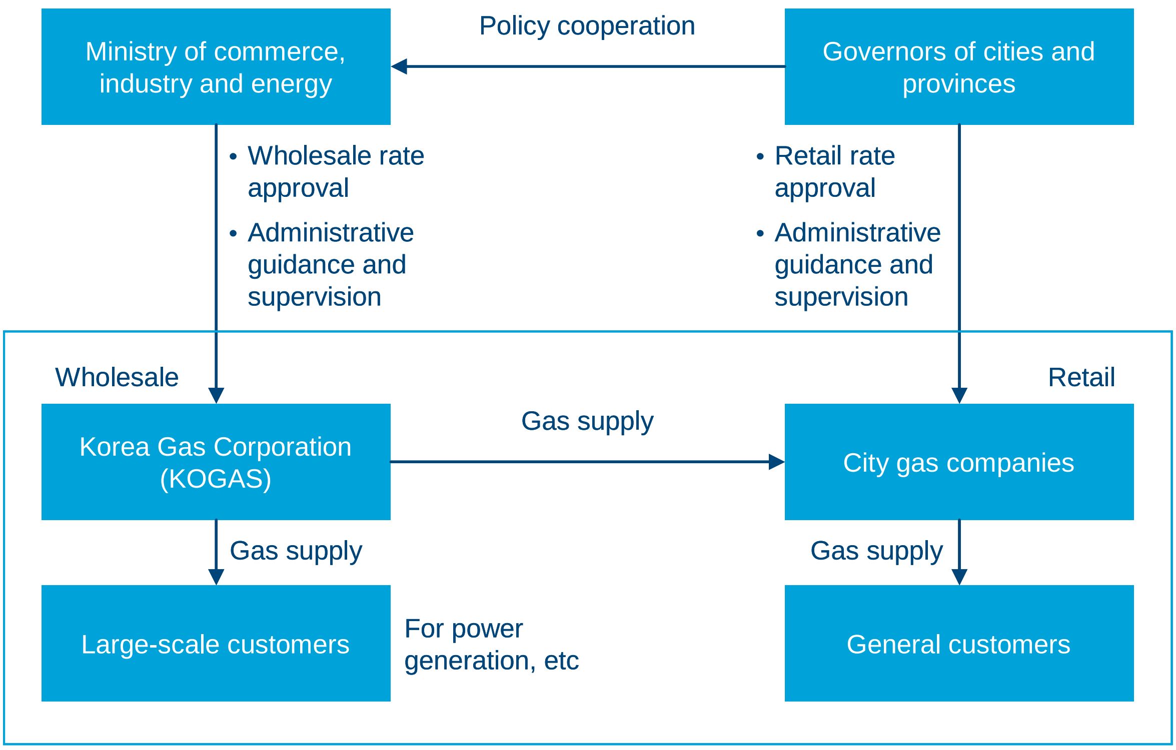
KOGAS supplies large scale customers, including the Korea Electric Power Company.

KOGAS also supplies gas to all the 33 local city gas companies, each having a monopoly over a defined geographic territory to supply the smaller retail customers.

The central government (MOCIE) oversees the wholesale market rates and administration, while the local governments and provinces oversee the retail market.

Figure 9.6 displays the industry market structure by entity and value chain components.

Figure 9.6 Natural gas industry market structure



Source: IEA The Republic of Korea 2006 review

Wholesale pricing

KOGAS determines cost-based rates for natural gas from the imported price of LNG.

In addition to the cost of LNG imports, rates include additional domestic costs associated with LNG importing, including import tariffs and levies, handling charges, a special excise tax and a safety management fund contribution.

KOGAS is allowed to recoup all the actual costs and is allowed a return on the investment. There have been occasions when the MOCIE has interfered and stalled the full pass through of gas prices for fear of inflation.

The MOCIE is working on a pricing mechanism that better reflects the higher cost of seasonal variations in demand for gas and electricity.

Retail pricing

City gas law regulates retail markets, and oversight by local governments and provinces prevents monopolistic behaviour in pricing. Prices vary for industrial and residential customers. Rates vary bimonthly for industrial customers, but are fixed annually for residential customers and do not vary according to season, despite the wide swings in seasonal residential consumption.

9.2.6 Policies for cleaner fuels

Korea is one of the parties to the United Nations Framework Convention on Climate Change (UNFCC) and has ratified the Kyoto protocol. It is a non-Annex I country and therefore does not have a reduction target for greenhouse gas emissions.

2.1% of total primary energy supply was contributed by renewable sources in 2004. The government's target is to raise this level to 5% by 2011.

Korea introduced the energy efficiency scheme in 2004, targeted at achieving greater efficiency in use of fuel. The plan introduces fuel economy standards in vehicles and standards for standby power appliances. Korea is expected to substantially increase emissions in the next 10-20 years, and so far does not have a mechanism to price carbon.

10 United States of America

10.1 Overview – US gas market

The United States of America (US) has a long history of being both a gas producer and a gas consumer. It is the world's largest user of natural gas, with consumption of 23 Tcf accounting for 22.6% of total worldwide consumption of natural gas in 2007. It is the second largest producer of natural gas after the Russian Federation.[53] However, consumption outpaces production, and significant imports of natural gas are required to meet demand.

The energy outlook for the next couple of decades (assuming current laws, regulations, and policies) is for continued growth and reliance on the three major fossil fuels (petroleum, natural gas, and coal), modest expansion in renewable resources, and relatively flat generation from nuclear power.[54]

The industry has a high degree of private ownership with little vertical integration. Production, transmission and distribution are usually separate entities, with only a few cases of upstream or downstream integration. A few large distributors own transmission pipelines, but this is quite rare.

The US natural gas market is extensively developed in all stages of the gas supply chain.

Figure 10.1 The US gas supply chain

10.1.1 Exploration and production

The US has some of the most prospective exploration capacity worldwide. Much of its reserve base, currently defined as significant gas resource, still exists in its frontier regions and in Alaska. As at the end of 2007 the proved reserves in the US were 237 Tcf.[55]

According to the Energy Information Administration (EIA), 19.5 Tcf of dry natural gas was produced in the US in 2007. This represented about 85% of total domestic consumption, and makes natural gas a fuel of choice in terms of energy security, especially when compared to oil, where there is a significantly stronger reliance on imports.

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[53] BP Statistical Review of World Energy 2008

[54] EIA Annual Energy Outlook 2008

[55] EIA website

Natural gas is produced from multiple basins around the country. This has provided a level of supply security in its major consuming centres given the potential for extreme weather conditions, particularly in the Gulf of Mexico.

In addition to conventional natural gas reserves, the US has established significant reserves and production in both coal bed methane and shale gas.

Figure 10.2 US gas reserves and production in 2007

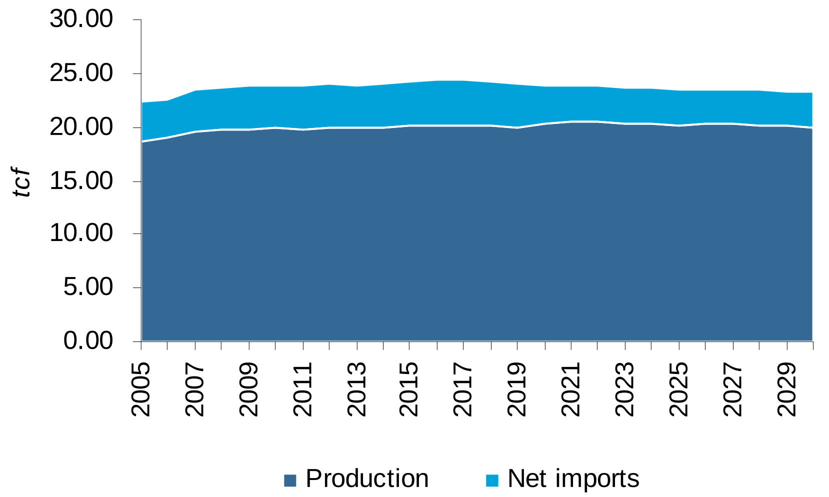
	Reserves (Bcf)	Production (Bcf)
Dry natural gas	237,726	19,466
Coal bed methane	21,875	1,754
Shale gas	Not available	Estimate 1,250[56]

Source: EIA (dry gas and CBN) and Platts (shale gas)

There are a number of major gas producers in the US, a large number of which are independent. The major natural gas producers include: ConocoPhillips, Anadarko Petroleum, Chevron Exxon Mobil, Shell Oil, BP America, Amerada Hess Corporation, El Paso Energy, and Apache.

As most of the US reserves of conventional gas are mature, unconventional resources like coal bed methane and shale gas are expected to increasingly contribute a greater share of gas production in the future.

Figure 10.3 US gas supply as forecasted by the EIA (Tcf)



Source: Energy Information Administration website

[56] Platts webcast September 2008. Shale gas production of 3-4 Bcf / day in 2007 is forecast to increase rapidly and may exceed shale gas production in 2008/2009. (Source Lippman Consulting).

10.1.2 Imports and exports

Interestingly, the US is both an importer and an exporter. Traditionally, its main trading partner has been Canada, with the US being a net importer. The North American markets are highly integrated, with transmission networks connecting the continent.

In 2007 the US imported a record 4.6 Tcf of natural gas.[57] This includes 3.8 Tcf via pipelines from Canada and 16 Mt (775 Bcf) of LNG from various other supply sources. It exported about of 0.8 Mt (41 Bcf) of LNG, from Alaska to Japan, and 310 Bcf of natural gas to Mexico via pipelines.

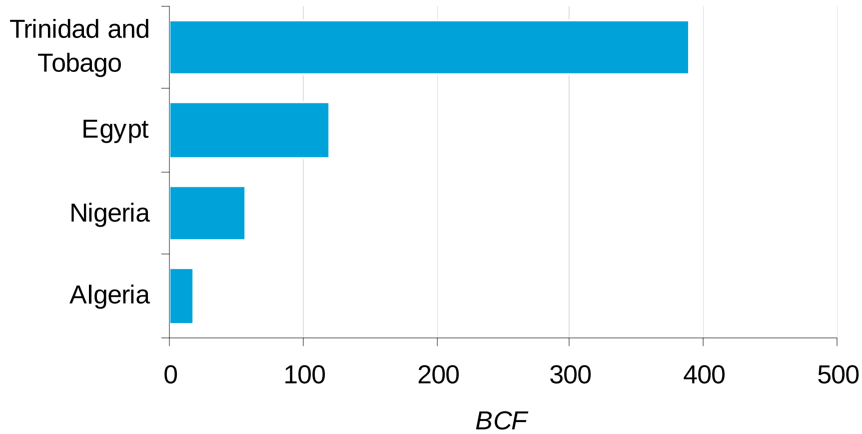
In recent years, with expectations of declining Canadian supplies and increasing US consumption, LNG imports have become increasingly important. Currently, LNG supplies 3% of US natural gas requirements. Industry and the government have previously projected this figure to approach 20% by 2025, but these estimates may be revised down if gas production from unconventional sources continues to increase.

LNG

LNG has been a part of the US gas market for several decades; however it has recently become more competitive on price and therefore increasingly important.

In 2007 the US received the majority of its LNG from the following countries:

Figure 10.4 US main source of imports



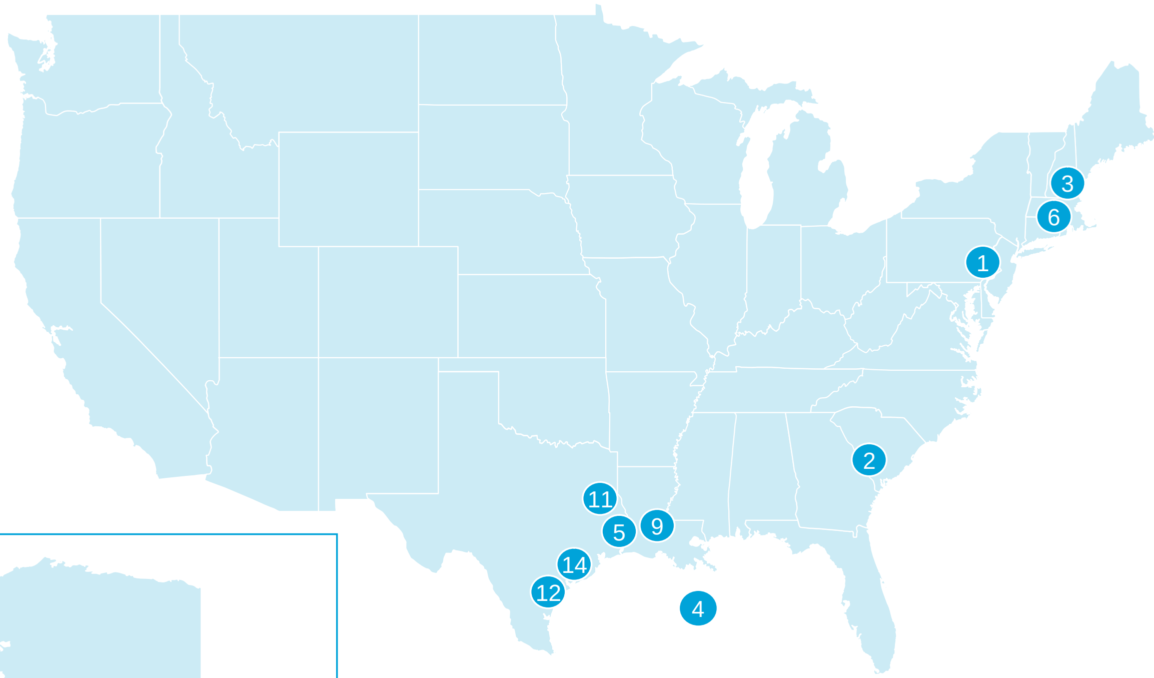
Source: BP Statistical Review of World Energy 2008

In addition, smaller volumes were also received from Qatar and Equatorial Guinea in 2007.

[57] EIA website and IEA Natural Gas Market Review 2008

The LNG import capacity of about 50 Mt (2,4 Tcf) per annum is more than 3 times the current level of imports. Several new LNG facilities are at different stages of approval/ construction. While it is likely that natural gas imports will increase, the need for further importing terminals will also be influenced by the development of non-traditional gas resources in the US and Canada. Figure 10.5 illustrates the extent of proposed LNG receiving terminals.

Figure 10.5 US natural gas pipeline flows and proposed LNG terminals



	Name	Capacity (BCFD)	Type
1	Cove Point LNG	1.0	Re-gasification
2	Southern LNG	1.2	Re-gasification
3	SUEZ LNG	1.035	Re-gasification
4	Energy Bridge	0.5	Re-gasification
5	Trunkline LNG	2.1	Re-gasification
6	Northeast Gateway	0.8	Re-gasification
7	Kenai LNG	1.3	Liquefaction
Currently under construction			
8	Elba Island [Expansion]	-	Re-gasification
9	Cameron LNG	11	Re-gasification
10	Cove Point [Expansion]	-	Re-gasification
11	Sabine Pass LNG	20	Re-gasification
12	Corpus Christi LNG	20	Re-gasification
13	Golden Pass LNG	15.6	Re-gasification
14	Freeport LNG	11	Re-gasification

Source: Energy Information Administration, FERC, Trade Press

10.1.3 Gas transportation and storage

Exploration and production | Imports / exports | **Gas transport and storage** | Gas markets | End users

Pipeline transmission and underground storage are vital elements of the US's natural gas transportation system. Mainline gas transmission pipelines provide the link between producing areas and the market place, while storage facilities ensure energy security and reliability of supply.

A challenge the US faces is how to encourage investment to replace obsolete infrastructure. Over 80% of its pipeline infrastructure was installed before the 1970s.

Transmission

Pipelines can be characterised as 'interstate' or 'intrastate':

- Interstate pipelines carry natural gas across state boundaries and in some cases across the country.
- Intrastate pipelines transport gas within a particular state.

About 80 systems make up the interstate transmission network. Another 60 systems operate strictly within individual states.

Figure 10.6 The US natural gas transmission network

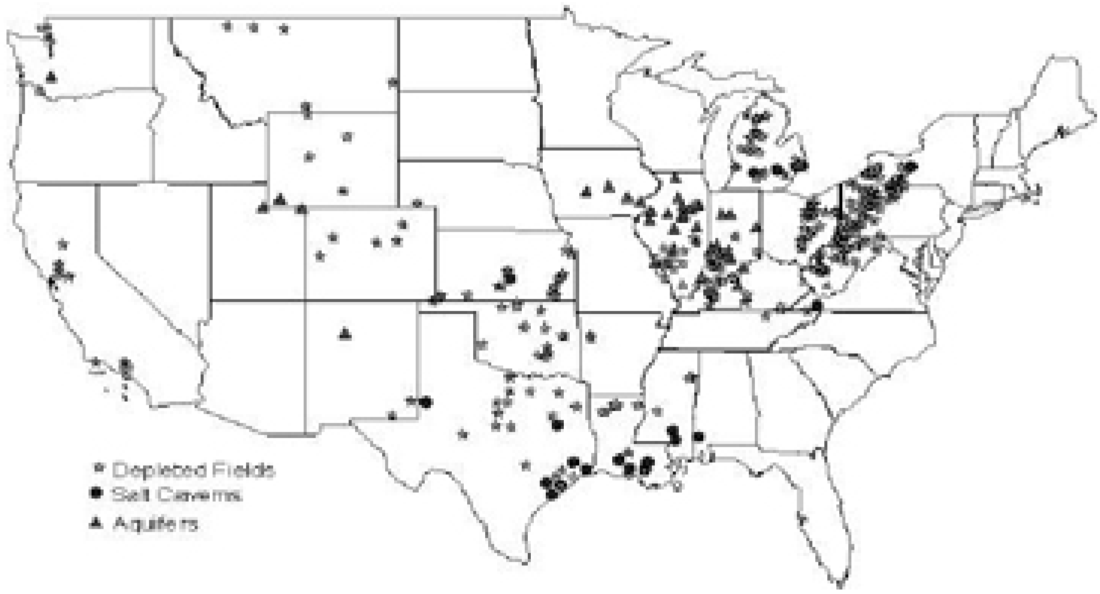
Source: IEA – The United States 2007 Review

Storage

Natural gas is usually stored in large underground reservoirs. Gas storage is the primary way the industry can manage fluctuations in supply and demand, and allows production fields and transmission pipelines to function at a more constant and efficient rate. There are over 400 underground storage facilities with a storage capacity of 4,059 Bcf, and more are being proposed. Note that the largest concentration of gas storage occurs close to the demand centres in the East and Midwest.

The purpose and use of storage has been closely linked to the regulatory environment of the time. Traditionally, storage served as a buffer between transportation and distribution, to ensure adequate supplies of natural gas were in place for seasonal demand shifts, and unexpected demand surges. Now, in addition to serving those purposes, natural gas storage is also used by industry participants for commercial reasons. Figure 10.7 displays the location of gas storage throughout the US.

Figure 10.7 Location of US natural gas storage facilities



Source: EIA – Form EIA-191, 'Monthly Underground Storage Report

Distribution

The US has an extensive gas reticulation network across the country. There are numerous local distribution companies (LDCs) in each state, providing customers with access to the distribution network.

LDCs are involved in the delivery of natural gas to consumers within a specific geographic area. Some are privately owned and some are owned by local governments.

LDCs have historically offered a final bundled price to consumers but this is changing. Most now offer unbundled transportation and storage services to industrial and larger commercial customers. For residential customers, a growing number of states allow purchase of gas from retail marketers as well as from the traditional gas utility.

LDCs transport natural gas from 'citygates' to the customer's location. Typically, LDCs take ownership of the natural gas at the citygates, which makes them important market centres for pricing of natural gas.

10.1.4 Gas markets

The US is the largest market for natural gas in the world. Deregulation of gas production prices and restructuring of the national gas market has taken place over several decades. This has created an efficient market that ensures that price signals are quickly and transparently transmitted between producers and consumers. Local markets are integrated with regional and international markets, like Canada and Mexico.

Wholesale markets

The natural gas wholesale markets are dynamic and highly competitive, with very active spot, forward and futures markets. Like most commodity markets, it allows for physical and financial trading among the various participant types: producers, marketers, retailers, end-users and LDCs. Financial trading in gas has helped the market develop liquidity and efficient risk management products.

Gas and pipeline capacity are typically provided under long-term bilateral contracts for services, and are actively traded in two discrete markets:

1. Gas (sold in an unregulated energy market).
2. Transportation (subject to a regulated capacity market and through capacity release).

Gas trading largely occurs at ‘hubs’- convergence of pipelines or storage facilities- where spot markets have emerged for managing short-term fluctuations in supply. The Henry Hub in Louisiana, which largely serves the eastern demand centres, facilitates a spot market for both gas and pipeline capacity. In addition, the New York Mercantile Exchange operates a natural gas futures market using Henry Hub prices as its delivery point.

Marketing

Marketers are intermediaries in the gas industry. They secure gas supply and find buyers and also oversee all the intermediate steps required – for example, arranging transportation, storage, and accounting – to ensure that the natural gas reaches the end user.

Before the deregulation of the natural gas commodity market and the introduction of open access to pipelines, there was no role for natural gas marketers. Nowadays, marketing has become an integral component of the natural gas industry and it is the marketers who ensure a liquid and transparent market exists for natural gas.

Marketers may be affiliates of producers, pipelines, and local utilities, or may be separate business entities unaffiliated with any other players in the industry.

Retail markets

The US is in the process of moving towards full retail contestability, but complete price deregulation of the interstate natural gas market will take several years.

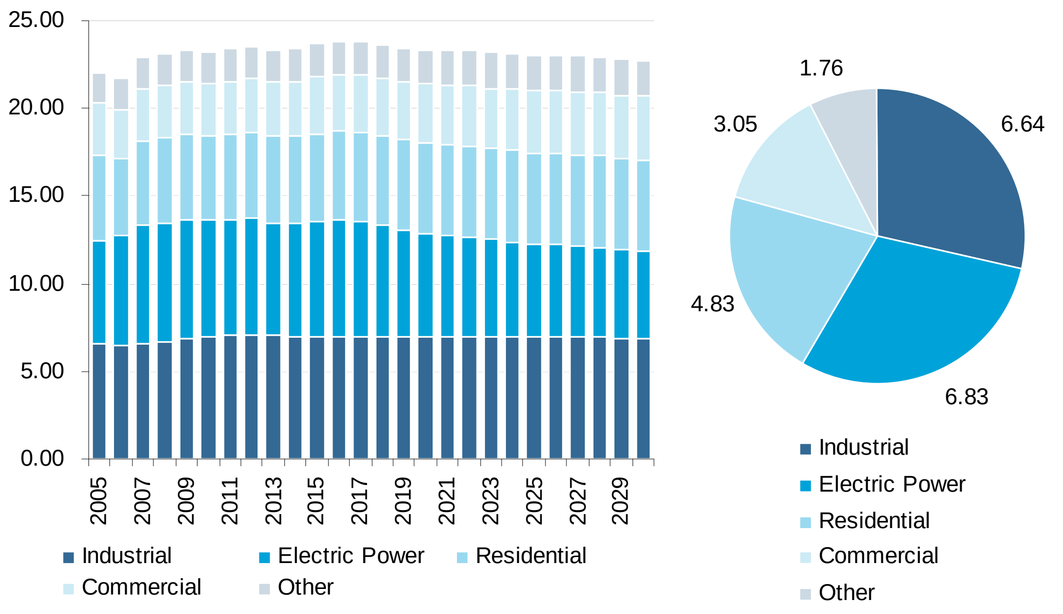
Most states have created individual restructuring plans enabling residential and small commercial customers (previously bound to purchase their natural gas from their local distribution company) to choose their preferred gas supplier. Several states have passed strict legislation opening up the retail market, while other states have been more reserved in allowing competitive retail supply for residential and commercial customers.[58]

10.1.5 End users

In 2007 US natural gas consumption was 23,057 Bcf. It is expected that US gas consumption will grow at an average annual rate of 0.6% between 2006 and 2030.[59]

There were nearly 70 million natural gas consumers in the US in 2006, with gas primarily consumed by the industry sectors articulated in Figure 10.8. The pie chart shows consumption in 2007 (Tcf).

Figure 10.8 US natural gas consumption by sector (Tcf)



Source: EIA

58 EIA, Natural gas marketer prices and sales to residential and commercial customers: 2002–2005

59 EIA, Annual energy outlook 2008

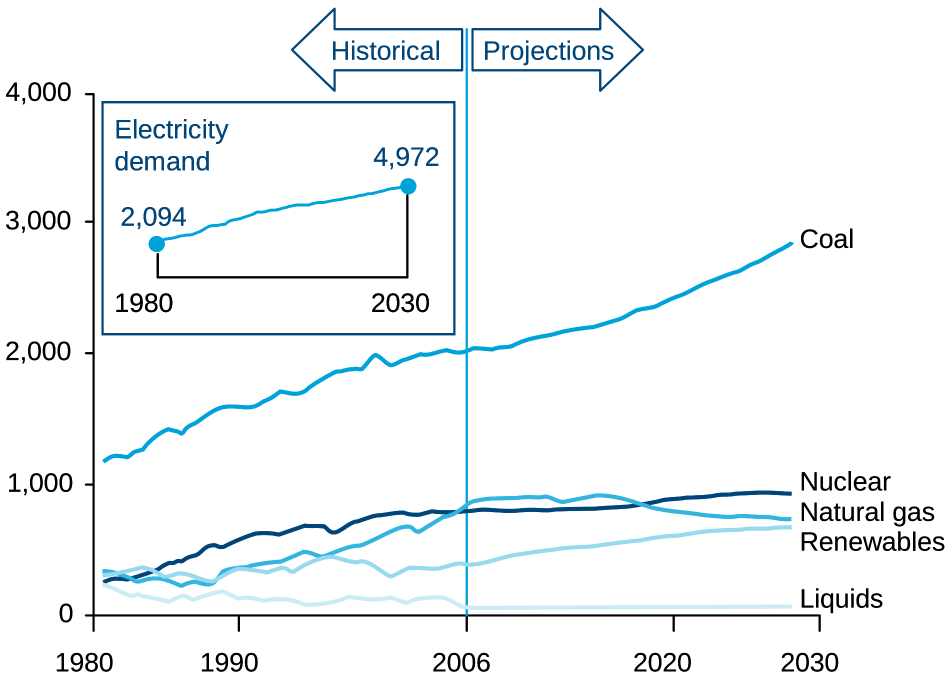
Residential consumption accounts for 22% of all natural gas consumption in the US. Most of the residential gas is used for space heating. Growth in this sector (as in the rest of the world) will be driven by population growth, energy efficiency regulations (natural gas being extremely efficient) and technological advancements that allow natural gas to compete with electricity.

Industrial demand accounts for 37.6% of demand, which is the highest of any sector. The use of gas is expected to increase because of factors such as cost efficiency deliverability, environment emissions regulations, and technological advancements.

Natural gas use in the transportation sector is still in its infancy; although natural-gas-powered vehicles present an enormous opportunity for cleaning up emissions from this sector. The demand for alternative fuel vehicles (including natural gas vehicles) is expected to increase in the foreseeable future, primarily due to high petrol prices and regulation on emissions.

The use of natural gas for power generation has been rapidly growing in the past decade, and a high proportion of growth in demand for natural gas is coming from this sector.

Figure 10.9 Electricity generation by fuel (billion kilowatt hours)



Source: EIA - Annual Energy Outlook 2008 with projections to 2030

The IEA expects electricity generation to grow at a reduced average annual rate of 1.1% towards 2030, which is significantly less than the growth rates of 2.6% and 2.3% in the 1980s and 1990s respectively. The share of gas is expected to remain relatively constant to 2016, and then decline as new capacity from coal, nuclear and renewable energy replaces gas.

10.2 Regulatory and legislative environment

The current regulatory environment in which the natural gas industry operates is much less stringent and relies more heavily upon competitive forces than in the past.

Deregulation of the industry started in 1978, as the Natural Gas Policy Act set the stage for phased de-control of wellhead prices. In the mid 1980s the Federal Energy Regulatory Commission (FERC) took action to reduce energy costs and improve the competitive position of natural gas against low-priced oil. There was also a reduction in vertical integration and the separation of production from transmission as different businesses.

10.2.1 Exploration and production

Natural gas producers and marketers are not directly regulated. This is not to say there are no rules governing their conduct, but there is no government agency charged with the direct oversight of their day-to-day business. Production and marketing companies must still operate within the confines of the law; for instance, producers are required to obtain the proper authorisation and permits before beginning to drill, particularly on federally owned land. However the prices they charge are a function of competitive markets, and are no longer regulated by the government.

10.2.2 Imports and exports

The Department of Energy and the Federal Energy Regulatory Commission (FERC) are responsible for the regulation of natural gas imports and exports, under Section 3 of the Natural Gas Act 1938. Under federal law, any company that wants to export LNG must first get Energy Department permission to ensure the export will not harm US energy supplies.

Under the terms of the North American Free Trade Agreement (NAFTA), producing companies operate freely across the US/Canada border. The natural gas pipeline transmission systems of the US and Canada are highly integrated.

FERC grants federal approval for the siting of new onshore LNG facilities. In December 2002, FERC exempted LNG import terminals from rate regulation and open access requirements. This regulatory action allowed import terminal owners to set market-based rates for terminal services, and allowed terminal developers to secure proprietary terminal access for corporate affiliates with investments in LNG supply.

10.2.3 Gas transportation

FERC has jurisdiction over the regulation of interstate pipelines and oversees the implementation and operation of the natural gas transport infrastructure. It regulates aspects such as approval, permitting and siting for new pipeline facilities, and transmission rates.

FERC obtains its authority and directives from a number of laws: the Natural Gas Act 1938, the Natural Gas Policy Act 1978, the Outer Continental Shelf Lands Act, the Natural Gas Wellhead Decontrol Act 1989, and the Energy Policy Act 1992.

In the past, interstate pipelines acted as both a transporter and a seller of natural gas, and both commodities were bundled into one product and sold for one price. However, since the introduction of FERC Order 636 in 1992, which opened up the natural gas market, interstate pipeline companies operate solely as transporters of gas under open access arrangements. Under federal regulations, interstate pipeline companies are required to provide their services on an unbundled basis. Many provide retail and marketing services through legally separate entities.

Capacity is typically provided under long-term contracts, with agreements specifying receipt and delivery points and the capacity amount. Pipeline operators must establish electronic bulletin boards to facilitate the trading of capacity, known as ‘capacity release’. Shippers holding capacity rights can re-sell their capacity either bilaterally or through the bulletin boards. Pipeline operators also post available capacity offers on their bulletin boards. Trade terms and conditions are set by the parties, but regulation requires that terms and conditions not be unduly discriminatory or preferential or exceed the regulated price cap. Any agreement reached where capacity is sold at a discount must be posted on the bulletin boards.

10.2.4 Gas storage

Storage plays a vital role in maintaining reliability of supply. Historically, when natural gas was a regulated commodity, storage was part of the bundled product sold by the pipelines to distribution utilities. This changed in 1992 with the introduction of FERC Order 636. Where previously storage had been required for pipelines’ operational requirements in meeting the needs of the utilities, it now became available to anyone seeking storage for commercial purposes or operational requirements.

10.2.5 Local distribution companies (LDCs)

LDCs are regulated by state utility commissions, which oversee their rates, oversee their siting, construction and expansion issues, and ensure proper procedure exists for maintaining adequate supply to their customers. This includes intrastate transportation over the utilities' transmission and distribution pipeline systems, storage, procurement, metering and billing.

Although these general objectives generally hold for all utility commissions, there are different processes and regulations in place across the country.

Regulation of distribution is currently undergoing a process of change, with many states exploring and instituting retail choice programs, allowing customers to use the LDC simply as a distribution transportation network.

10.2.6 Gas markets

The US wholesale gas market is liquid, transparent, responsive, highly competitive, and works very well. Wholesale markets are deregulated and gas is traded under a full array of bilateral contracts.

PART C Modelling of APP gas markets

Australia • Canada • China • India • Japan • Korea • US

11 Modelling of APP gas markets

11.1 Purpose and approach

The purpose of modelling the energy markets is to quantify the potential impact of growing gas utilisation in the APP economies. The impact is measured in terms of gas penetration, investments, greenhouse gas emissions, air pollution, energy security and economic growth.

Modelling of the APP economies was conducted in two separate stages and with the assistance of well recognised external models and expertise, detailed below:

Market modelling	• Services obtained from Intelligent Energy Systems (IES) in Australia. • Model: MARKAL linear programming model. • All countries were modelled individually. • Time frame: Annual impact from 2008 to 2025.
Economic modelling	• Services obtained from the Centre of Policy Studies at Monash University in Melbourne, Australia. • Model: GTAP multiregional CGE model. • GTAP database has input/output data for eight regions, the seven APP countries plus the rest of the world. • Time frame: Long term economic impact.

A detailed description of both the energy model and the economic model is provided in the appendices.

First, the energy market modelling was performed with the MARKAL linear programming model. A base case was established for each country based on available projections of energy consumption and other relevant data to 2025. This base case is then used as the basis for comparison when creating a scenario where identified barriers are relaxed.

Second, based on findings from the analysis of gas markets, a modified gas market scenario (referred to as the scenario) was established for each APP partner economy. The scenario was designed to reflect removal of several identified key barriers to gas market growth, and therefore reflect higher penetration of gas in each country's energy mix. The scenario is outlined in Section 11.2.

The model captured all sectors, but changes in behaviour and consumption was mainly reflected in the electricity sector. This is because electricity generation is most significant for gas market growth, particularly in the short to medium term, and the sector is well suited to model investments and market optimisation. Many of the conclusions from the modelling can be extended and applied to the broader economy.

Third, the following range of indicators was calculated for both the base case and the scenario:

- Energy consumption (in total and by fuel type) and investments for power generation and infrastructure for importing gas.
- Energy security measures related to diversity of supply, carbon / non-carbon mix of the portfolio and import dependency.
- Emission of greenhouse gases (carbon dioxide).
- Emission of air pollution (nitrogen dioxide, sulphur dioxide and particulates).

11.2 The gas market scenario

This study has identified a number of barriers and impediments to gas market growth, some of which are global in nature and some of which are country specific.

For the purpose of modelling the impact of removing of these barriers, different assumptions were made for the developing and developed economies in the APP.

Developed economies – Australia, Canada, Japan and the US

In order to increase gas penetration in these countries, it is necessary for the market to provide the right incentives to invest in and utilise clean fuels. Hence, one option is to impose a cost on carbon emissions. This cost will make gas more economical relative to coal, and it will also favour non-fossil fuels such as nuclear and renewable energy.

A projected carbon cost is incorporated into the modelling at $35 per tonne, consistent with prevailing prices for the European Union Allowance (EUA). The cost is modelled for the electricity sector. It is assumed that nuclear energy production will mirror the base case, but a modest increase in renewable energy has been allowed in Australia and the US.

Developing economies – China, India and Korea

In order to increase gas penetration in these countries, it is important to improve the level of certainty for investors and to establish government policies and regulations that support investments in infrastructure and utilisation of gas. For modelling purposes, the decision to support gas relative to other fuels (at least in the short term) can be regarded as an exogenous switch to gas.

The rate of switching has been assumed to be similar for the three countries, and is based on historical growth of gas penetration in other countries. The 0.625% growth of gas' share of total primary energy supply is split evenly between the electricity sector and the industrial sector.

Results of the energy market modelling are presented in Section 11.3.

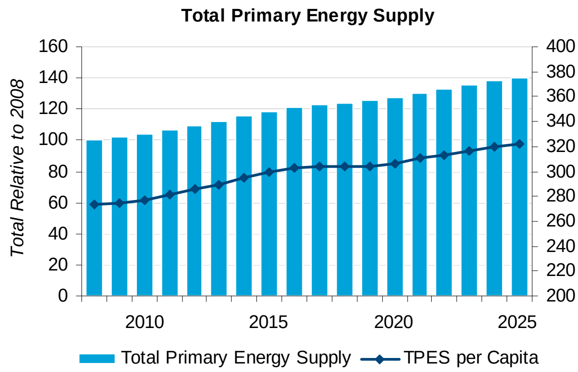
Finally, the GTAP model was calibrated consistent with findings from the energy markets with a view to analyse economic impact of higher gas penetration. Results from the economic modelling are discussed in Section 11.4.

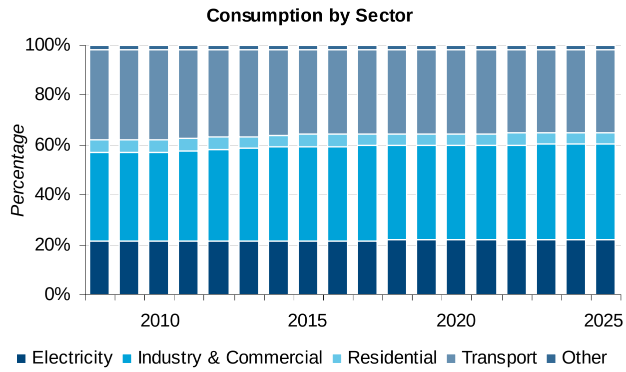
Further details and high level assumptions in relation to data and the approach to modelling are provided in the appendices.

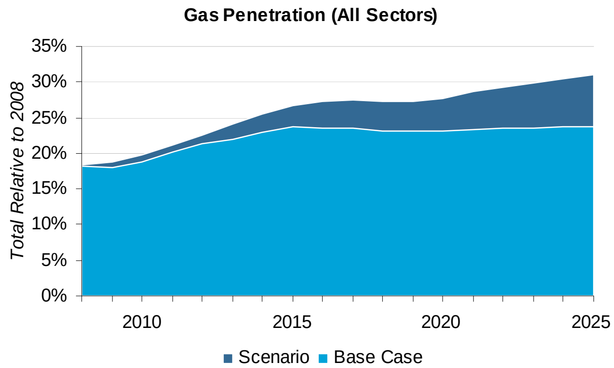
11.3 Scenario impact for each country

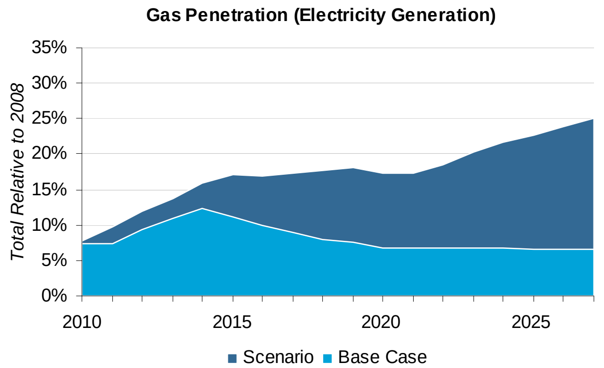
11.3.1 Australia

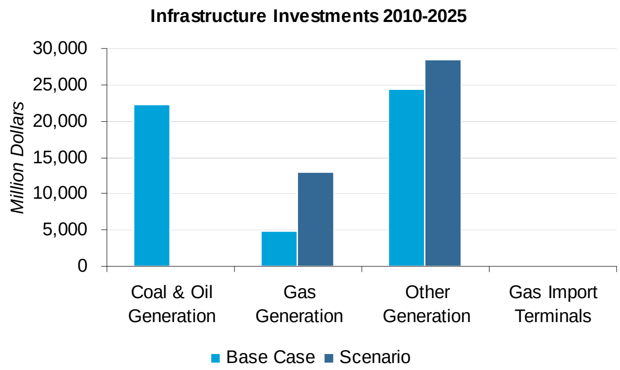
Energy consumption and investments

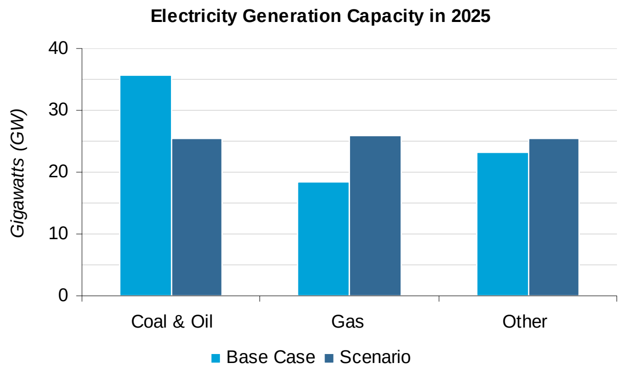








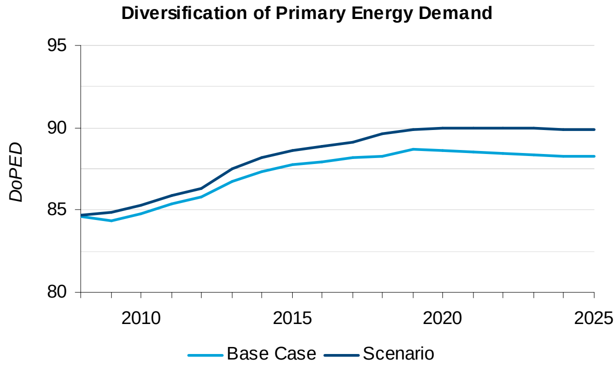


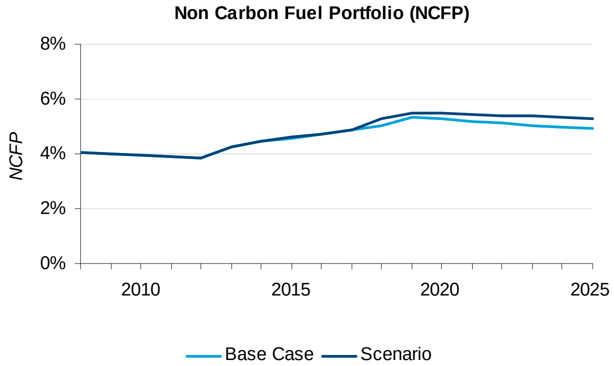


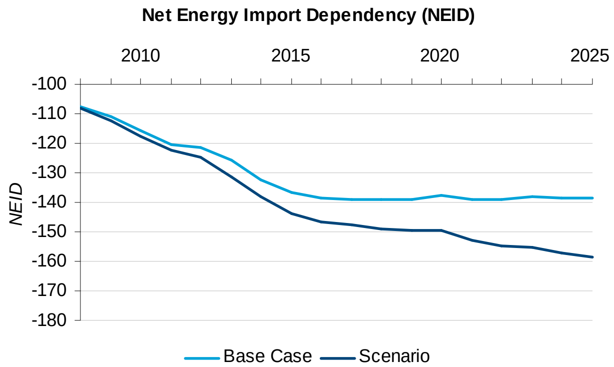
The industrial sector is the main user of gas in Australia. However, there is scope to further increase gas penetration, particularly in the electricity generation sector which today is dominated by coal fired plants.

Investments in the base case illustrate the current drive towards increasing the share of renewable energy in the energy mix. The scenario reflects investments in new gas generation capacity to meet new demand and retiring coal capacity. The result is that capacity in 2025 is shared evenly between coal, gas and renewable sources (as the dominant component in other generation), although coal will still represent more than half of the actual electricity output.

Energy security





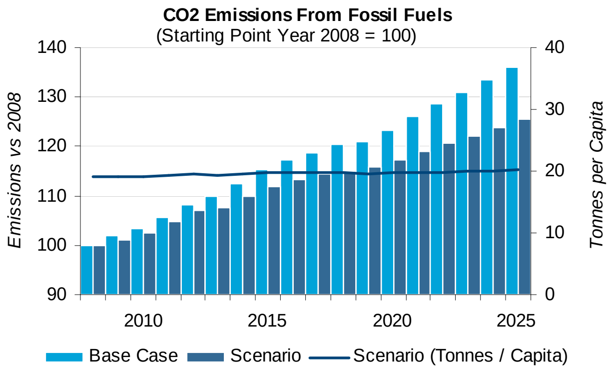


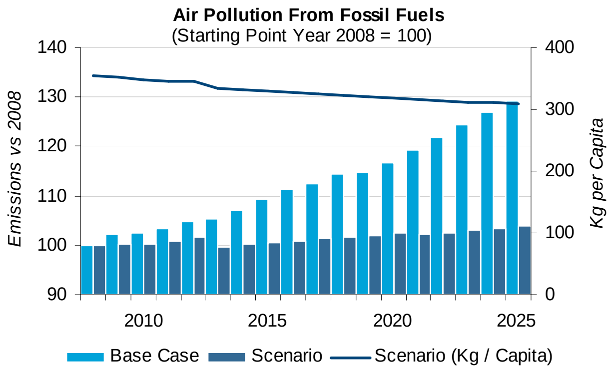
Diversification of primary energy demand improves relative to the base case as Australia's reliance on coal is reduced.

NCFP (which reflects the share of non-carbon fuel in total primary energy supply) increases.

Negative numbers for NEID reflect that Australia's status as an energy exporter will increase further throughout the period.

Emissions and air pollution





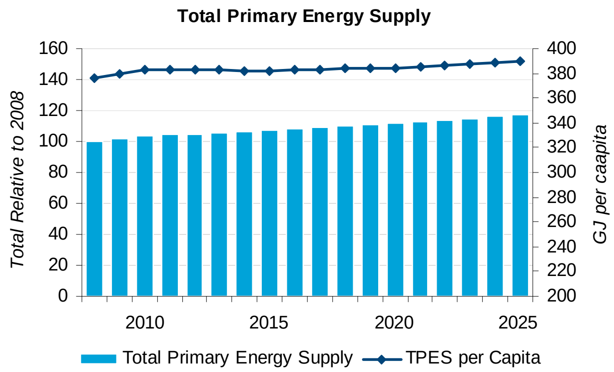
The Australian results illustrate how the move towards cleaner fuels will contribute to reduced emissions of both greenhouse gases (reflected as carbon dioxide in the figure) and air pollution (calculated as the sum of nitrogen oxides, sulphur dioxides and particulates).

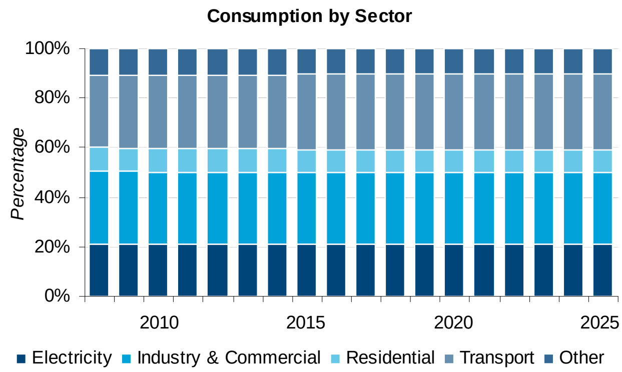
Whilst the base case emissions of both CO2 and pollution are significantly above current levels at the end of the period, CO2 emissions in the scenario shows an 8% reduction and air pollution shows a 20% reduction compared to the base case in 2025.

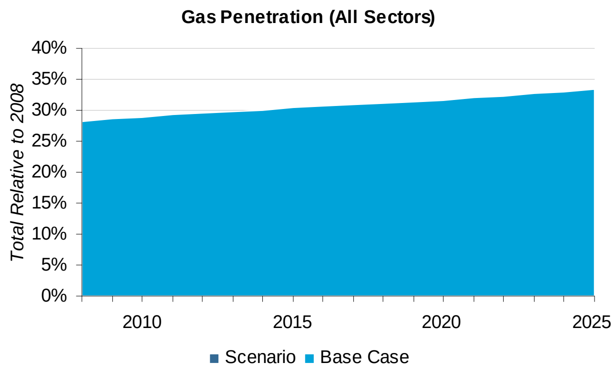
Australia's current air pollution per capita is higher than the other economies in this study.

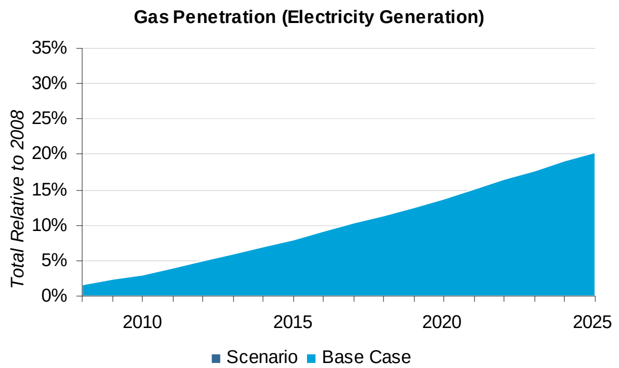
11.3.2 Canada

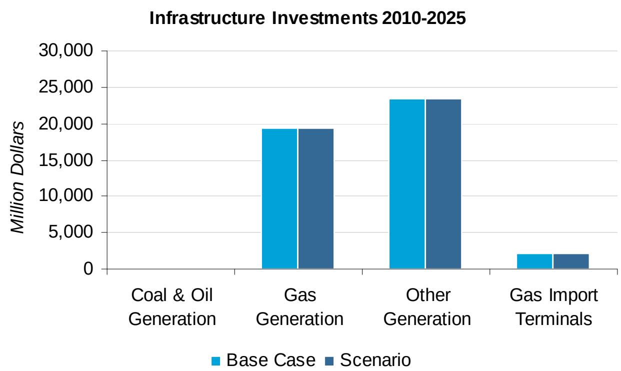
Energy consumption and investments

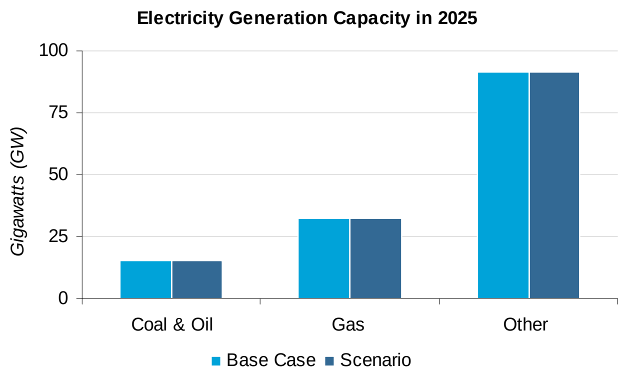










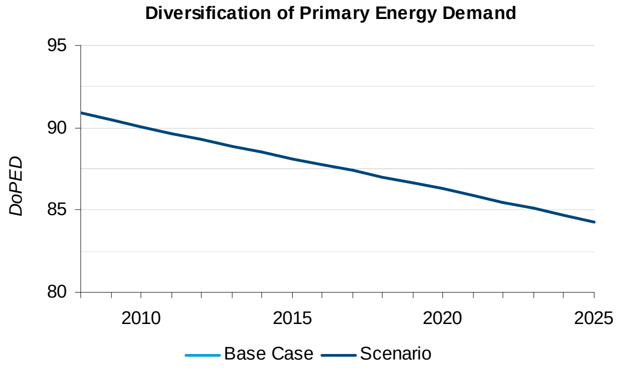


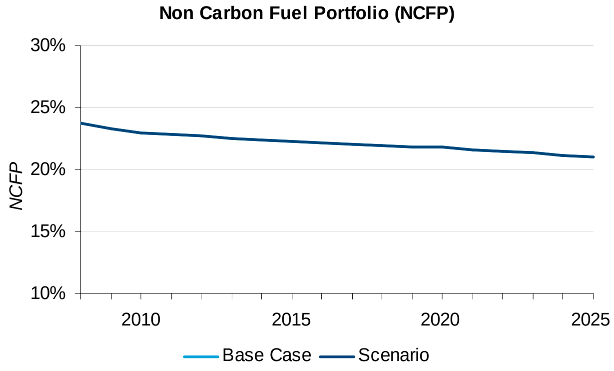
Canada has significant gas penetration across all sectors due to its historic position of being a low cost gas producer. For the purpose of this study, the base case and the scenario are identical. This reflects Canada’s existing long term plans and fortunate position as a country which is rich in energy resources.

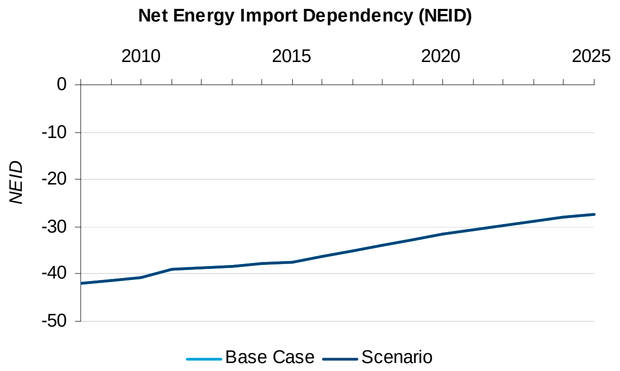
Canada’s gas penetration is high relative to other countries, and it is increasing towards the end of the period in line with planned investments in gas fired electricity generation. The base case does not assume any investments in coal fired electricity generation.

Longer term, the transport sector may offer opportunities to further reduce the use of crude oil and petroleum products. Plans to build gas import terminals towards the end of the period may reflect a need to maintain utilisation of current pipeline infrastructure.

Energy security



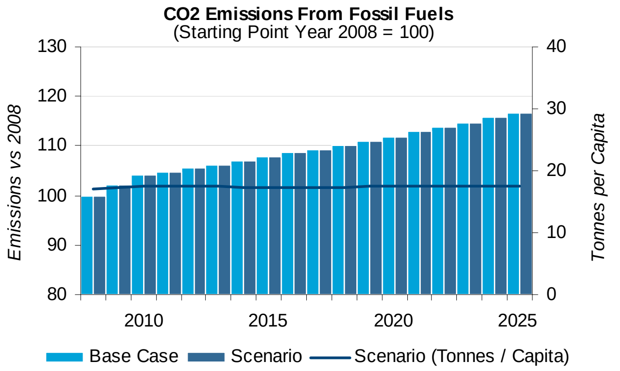


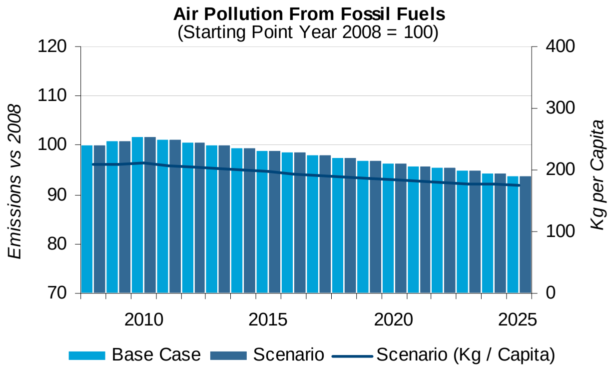


Increased use of gas will gradually affect the measures for diversification of primary energy demand and the share of non carbon fuels.

Net energy import dependency will change over time as Canada's export volumes to the US decline.

Emissions and air pollution



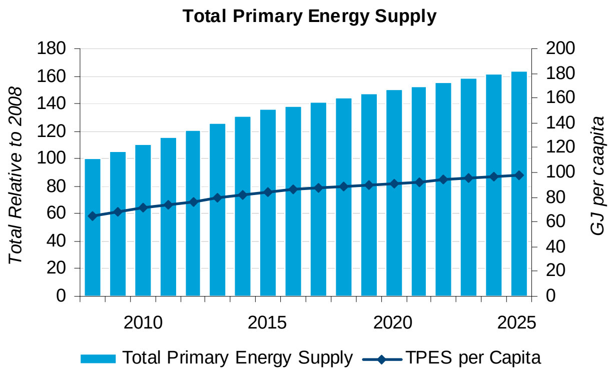


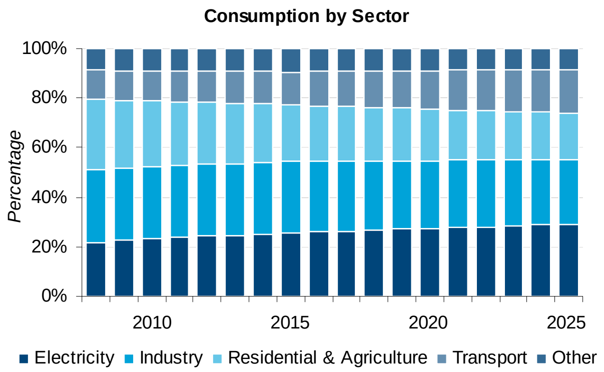
The 17% higher CO_2 emissions from fossil fuels are in line with the increased energy consumption in Canada over the period. The benefit of increasing gas and reducing oil consumption is offset by a lower share of nuclear and renewable energy in the portfolio.

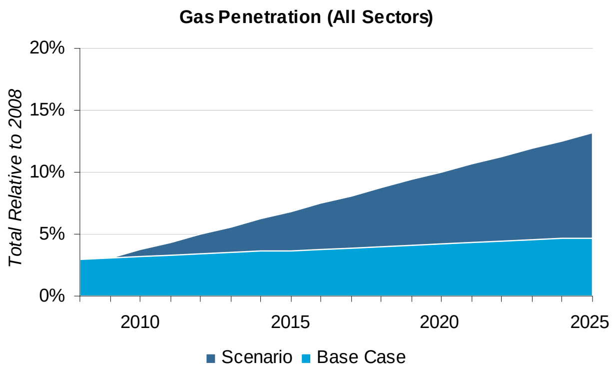
The benefit of higher forecast gas utilisation is fully reflected in the declining air pollution.

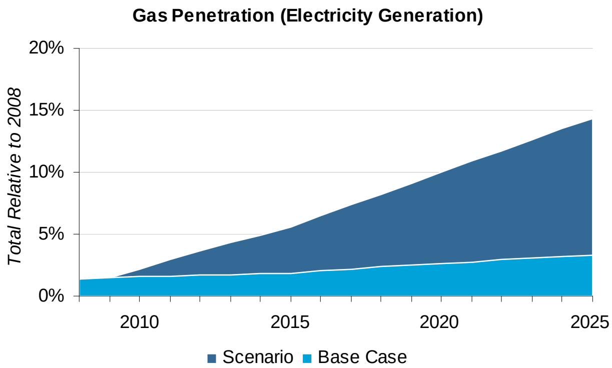
11.3.3 China

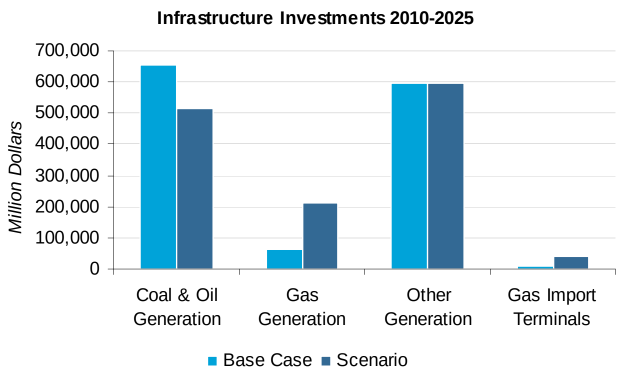
Energy consumption and investments

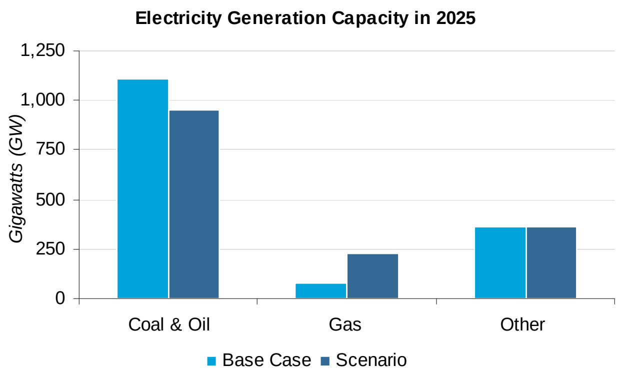










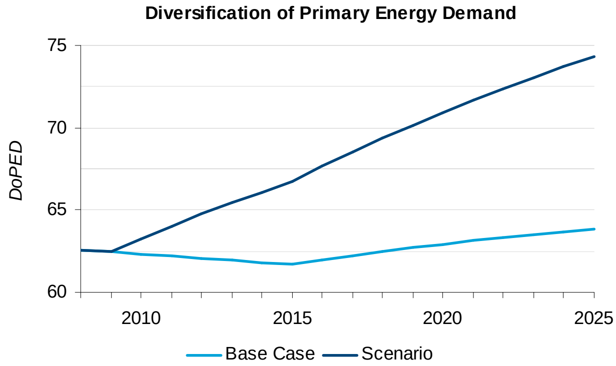


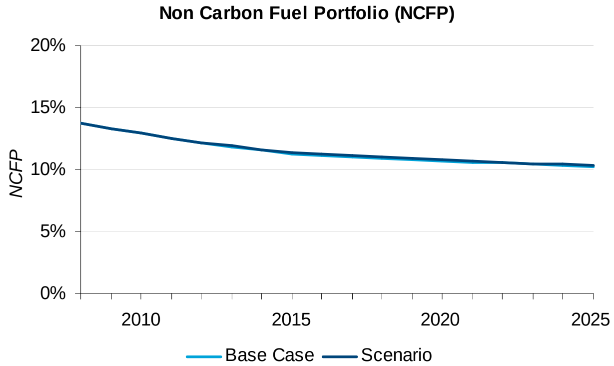
China's total primary energy supply is expected to grow by 64% to the end of the modelling period, but the consumption per capita will still be low compared to all APP Partners except for India. The electricity and transport sectors will increase most in percentage terms.

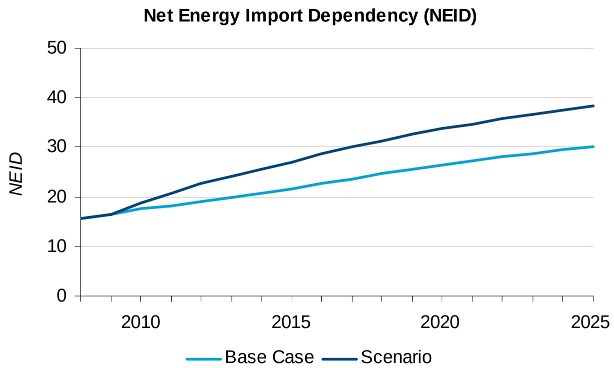
China currently has the lowest gas penetration of the APP7 and hence the greatest potential to increase consumption. The scenario assumes that growth is split evenly between the electricity and industrial sectors. Even with this rapid growth of gas usage, coal is by far the dominant fuel for electricity generation in 2025.

The investment forecasts illustrate that the cost of building gas import terminals is low compared to the total investments in generation capacity.

Energy security





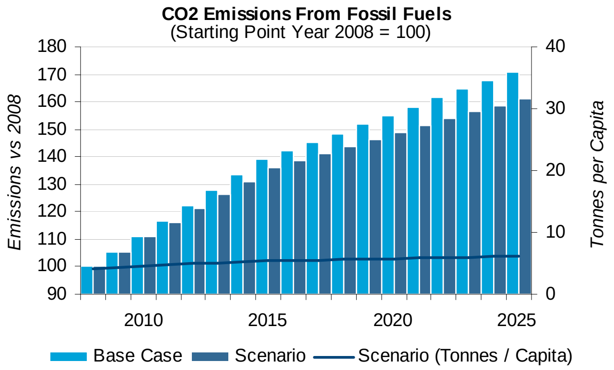


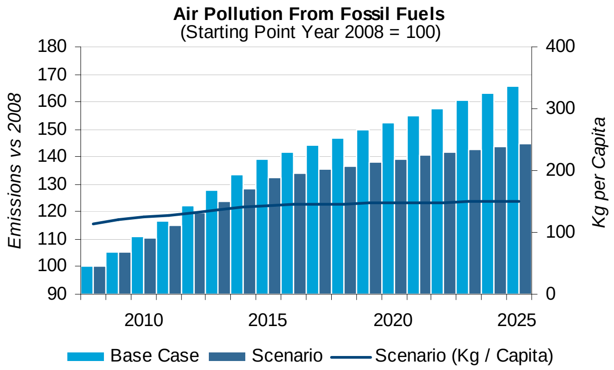
Increased gas penetration will have a positive effect on diversification of primary energy demand.

The share of non carbon fuels is projected to decline.

Net energy import dependency increases as it is assumed that the majority of new gas will be imported.

Emissions and air pollution





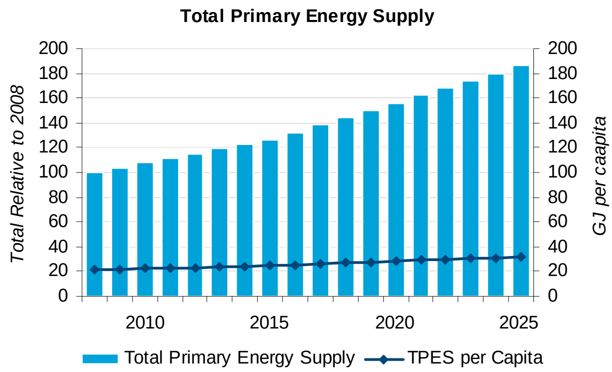
CO_2 emissions and air pollution in the scenario are respectively 6% and 13% below business as usual in the base case at the end of the period.

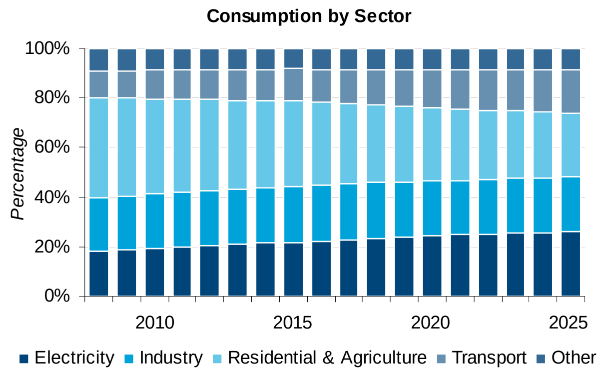
The measure of air pollution per capita reflects a high dependence on coal in the energy mix. Increased use of gas is one of several initiatives that can help contain growth in pollution.

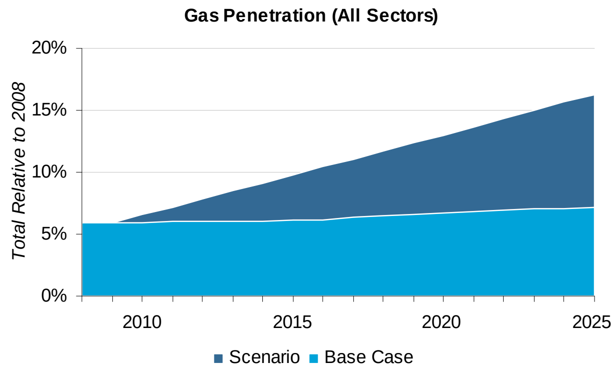
Burning of bio-mass in the residential sector is not captured in the forecasts of emissions and air pollution.

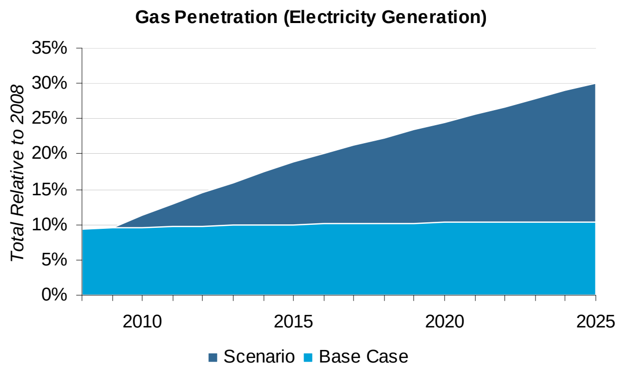
11.3.4 India

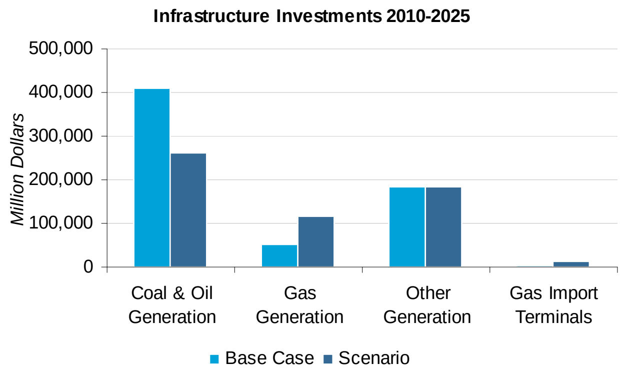
Energy consumption and investments

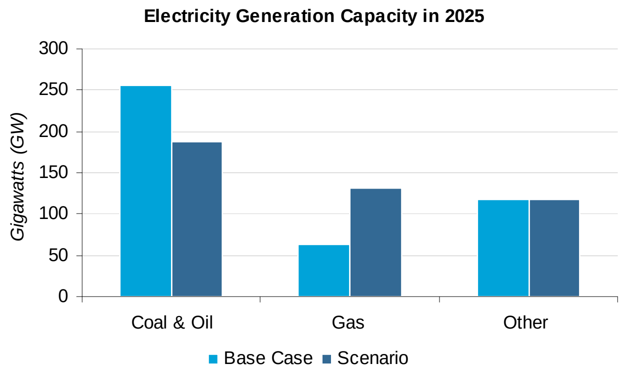








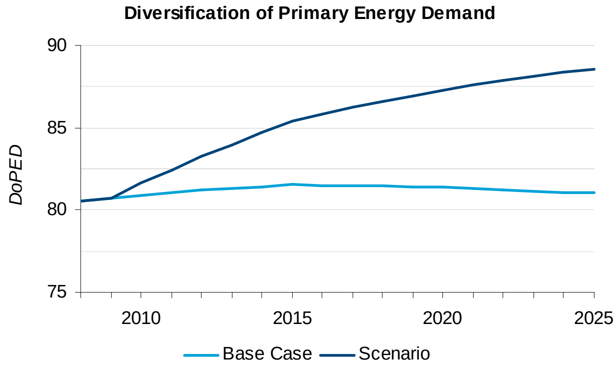


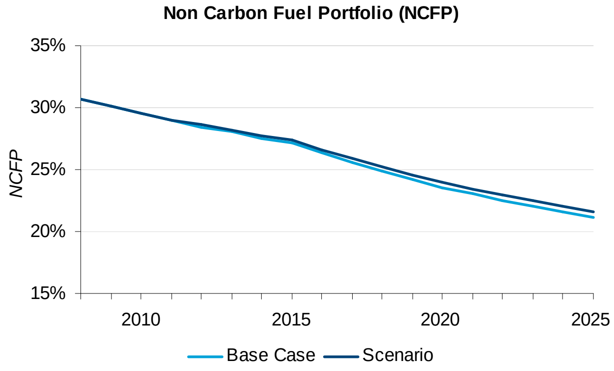


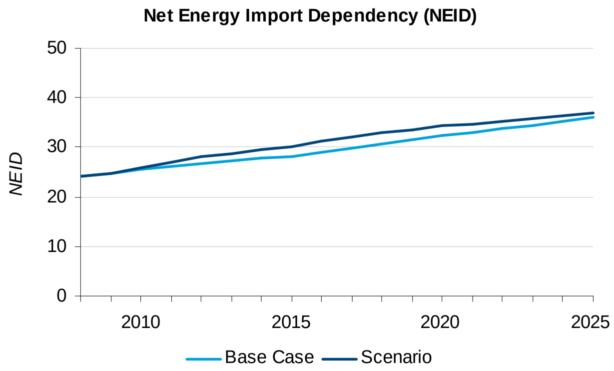
India's total primary energy supply is projected to increase by 86% to the end of the period. Consumption per capita is projected to reach 32 GJ pa which is one third of China's level and 10% of Australia's consumption per person.

The scenario reflects an increase in gas penetration to 16% in 2025, with the growth shared between industry and electricity generation. Coal is forecast to still produce 50% of India's electricity in 2025.

Energy security





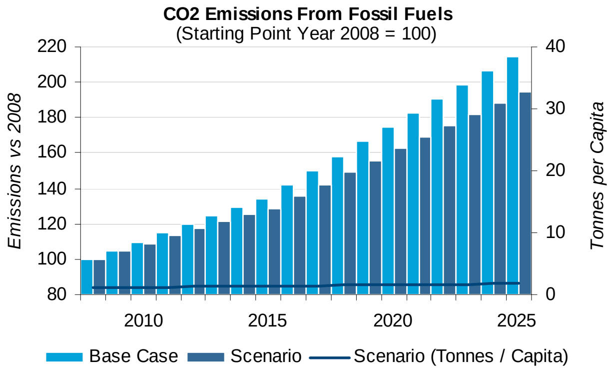


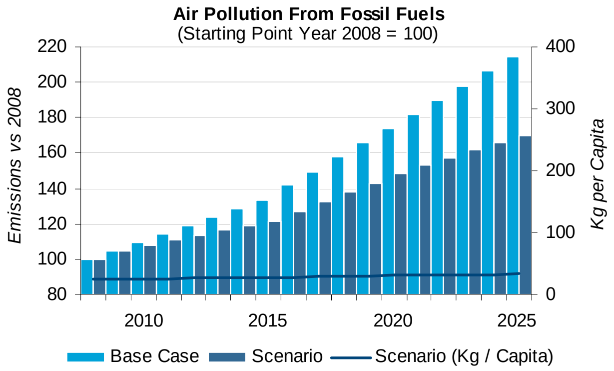
Increased gas penetration will have a positive effect on diversification of primary energy demand.

The share of non carbon fuels is projected to decline.

Net energy import dependency will increase both in the base case and the scenario.

Emissions and air pollution



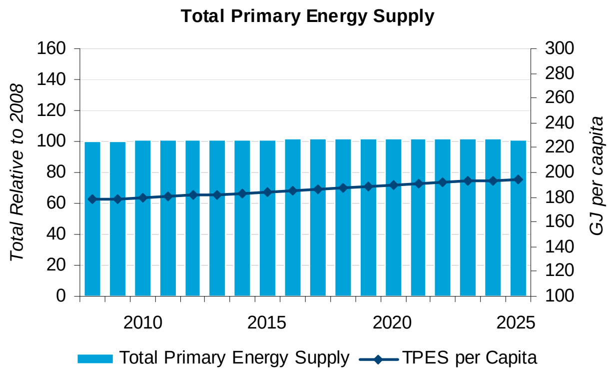


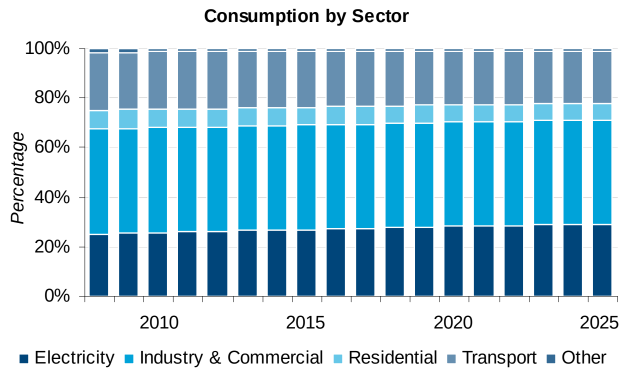
CO_2 emissions and air pollution in the scenario are respectively 9% and 21% below the base case in 2025.

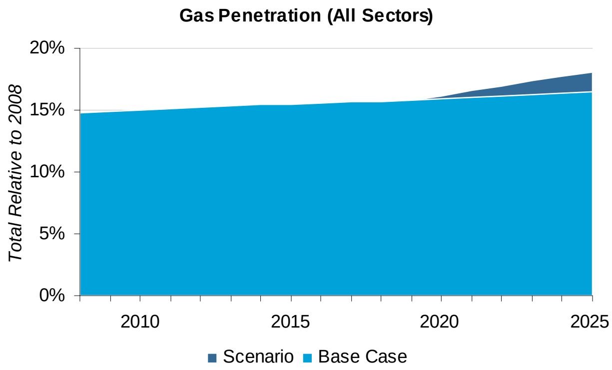
The measure of carbon dioxide emissions and air pollution per capita from fossil fuels is very low compared to all other APP Partners. The high proportion of burning bio-mass in the residential sector is not captured in the forecast.

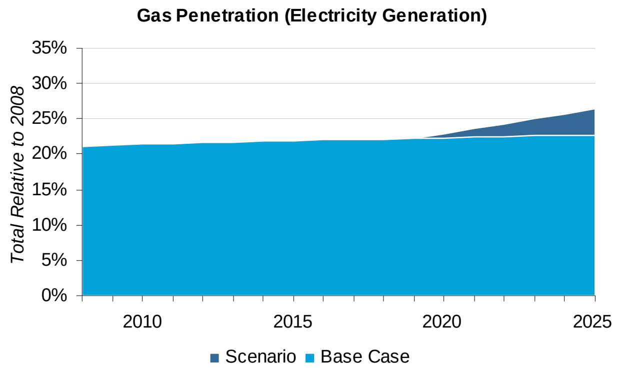
11.3.5 Japan

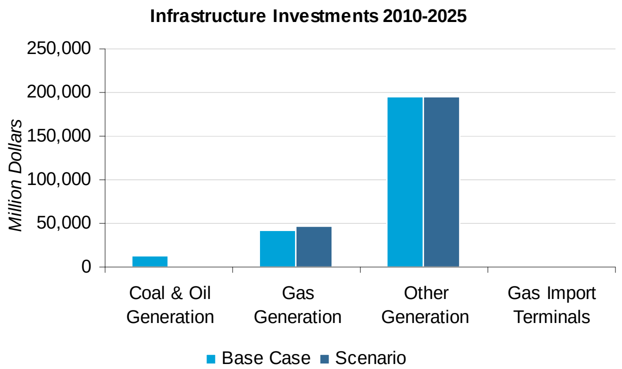
Energy consumption and investments

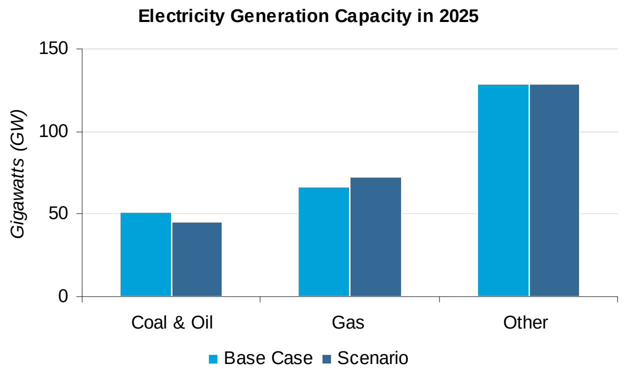










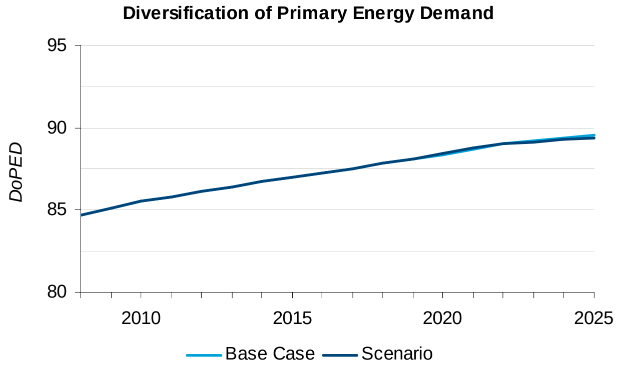


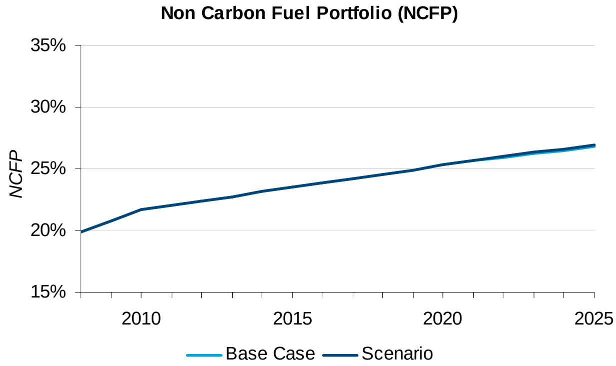
Total primary energy supply is expected to remain at current levels and the Japanese population is expected to reduce by 7-8% to 2025.

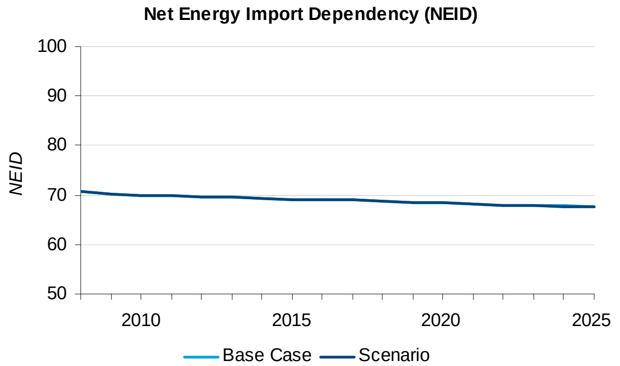
The majority of new electricity investments are planned in the nuclear sector, and there is only a limited opportunity to replace coal fired capacity with gas towards the end of the period. Other opportunities to increase gas penetration, mainly long term, could be found in the transport sector.

A carbon tax on fossil fuels will reinforce nuclear energy as the cheapest fuel option available.

Energy security

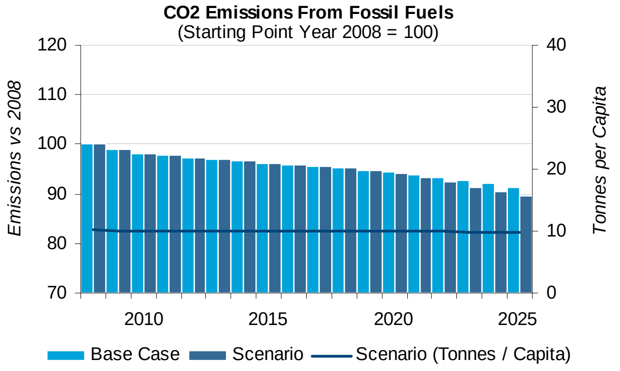


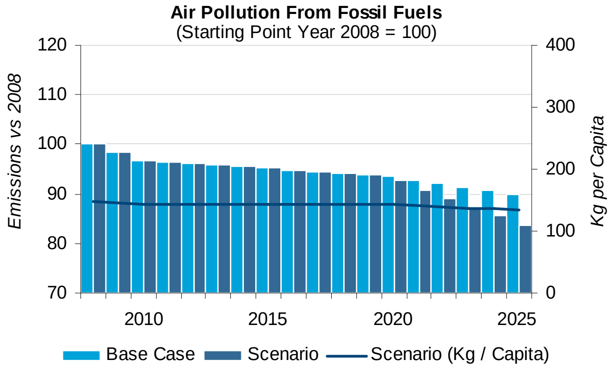




Japan’s energy security indicators show a positive trend throughout the period as oil imports are expected to decline and nuclear generation increases.

Emissions and air pollution



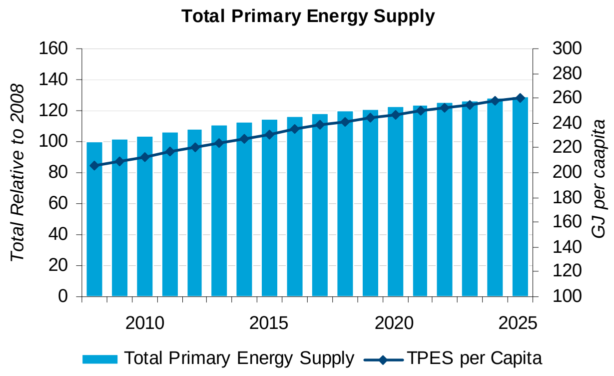


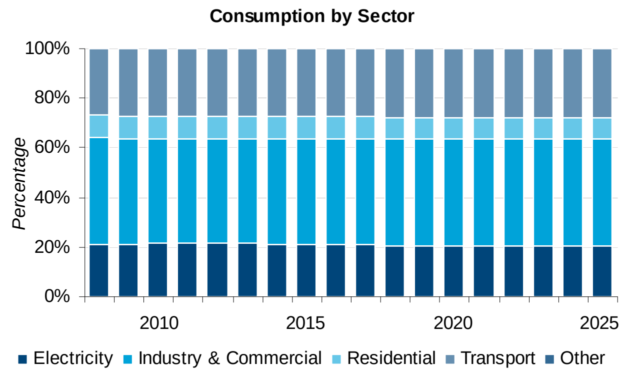
CO_2 emissions and air pollution are forecast to reduce in both the base case and the scenario.

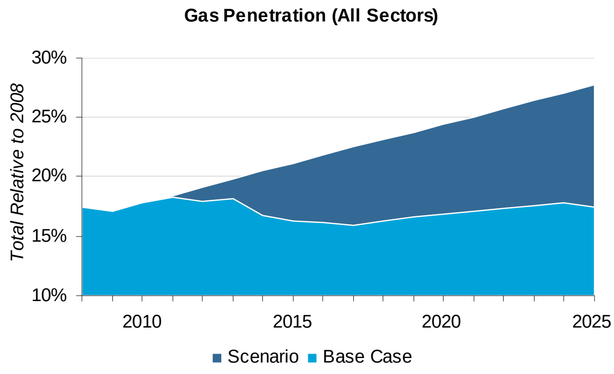
CO_2 emissions and air pollution are low compared to the other developed countries in the APP7.

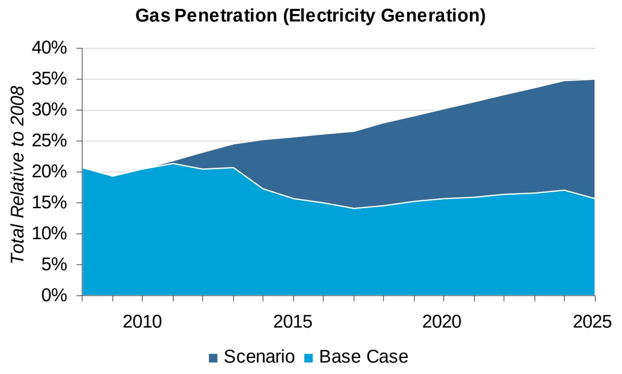
11.3.6 The Republic of Korea

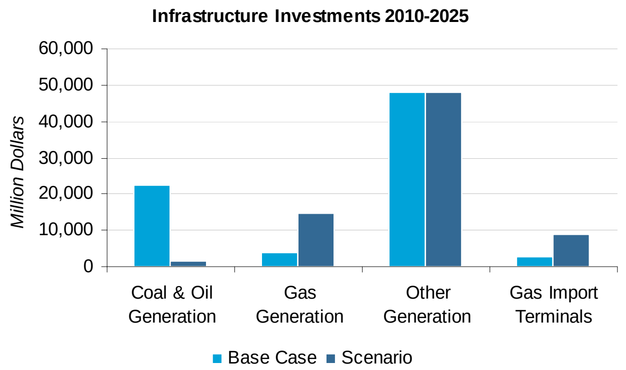
Energy consumption and investments

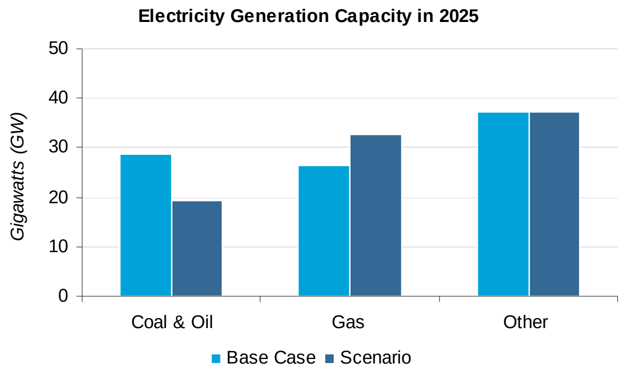










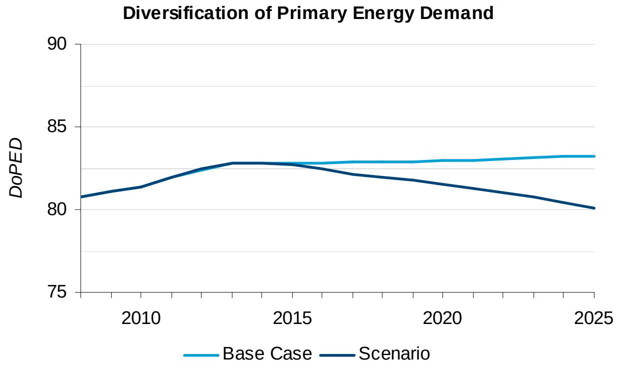


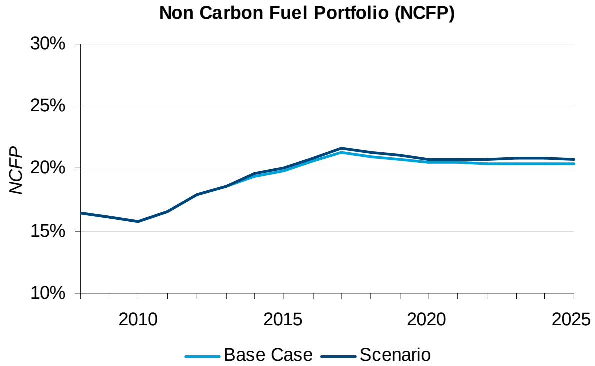
Korea's energy consumption per sector is similar to Japan, and the usage per capita is 15% above Japan.

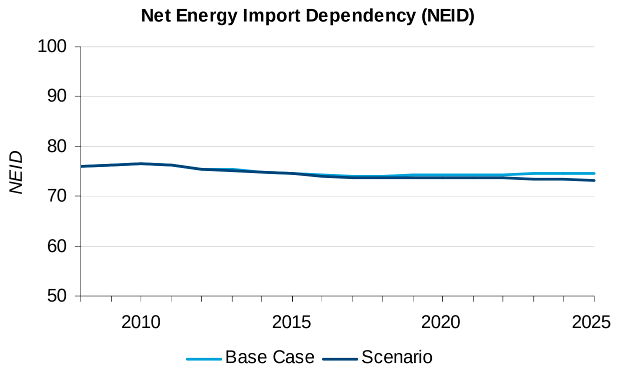
The scenario assumes increased gas usage by applying the same assumptions as for China and India. However, it should be recognised that Korea's current gas penetration is already significantly above the other two countries, and hence the higher gas usage may be more difficult to achieve. The greatest opportunity for increased gas penetration is in the electricity generation sector.

PwC's data reflects current gas penetration in Korea of about 17%, which is 3% above statistics published by some other sources. If the starting point is 3% too high, then output should be read in relative terms, (i.e. that gas penetration in the scenario increases from 14% to 24%).

Energy security



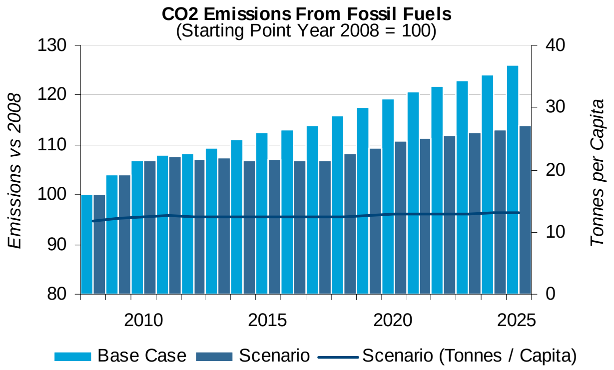


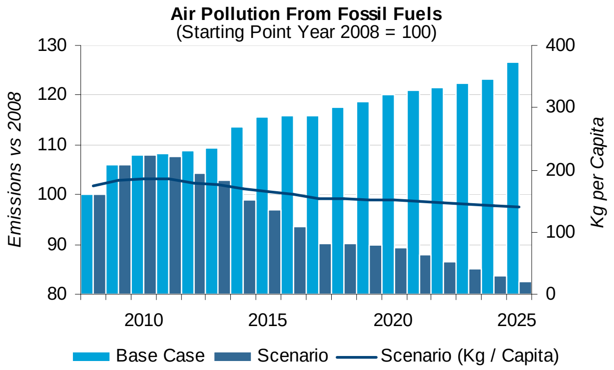


The measure for diversification of primary energy demand will start to decline towards 2025 if the share of coal in the fuel mix is reduced towards 10%.

The non carbon fuel portfolio is forecast to increase in line with new investments in nuclear power generation.

Emissions and air pollution

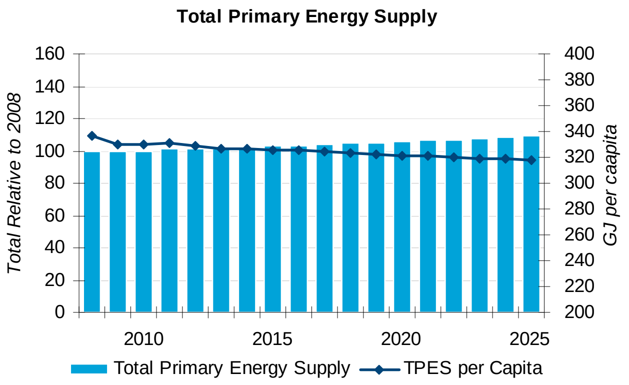


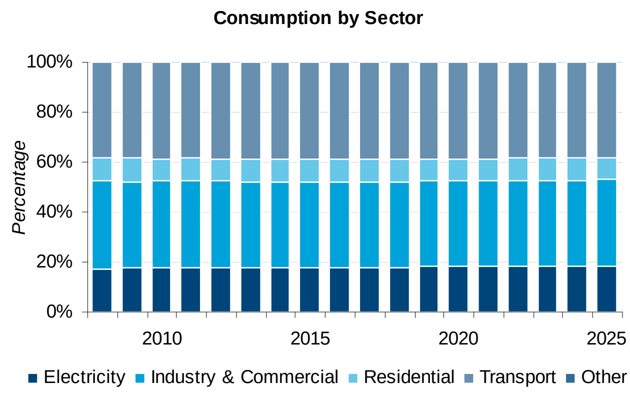


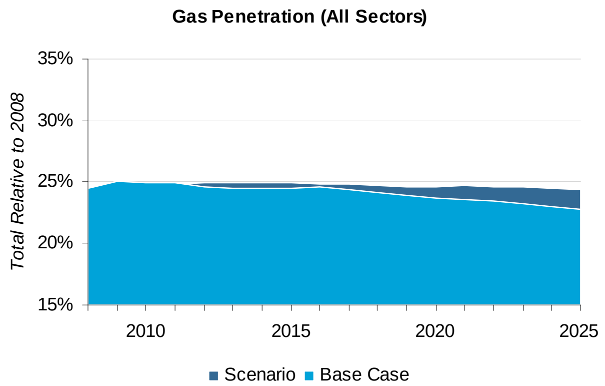
CO2 emissions and air pollution in the scenario are respectively 10% and 35% below the base case indicating a large decrease in fossil fuel pollution as a result of increased gas generation.

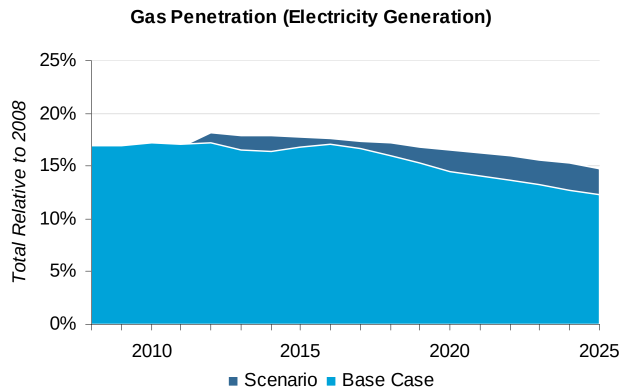
11.3.7 The United States of America

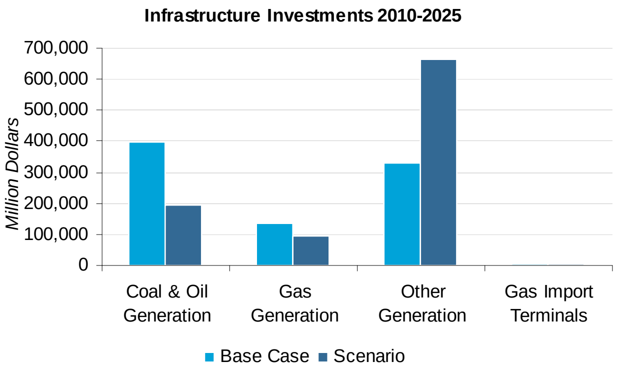
Energy consumption and investments

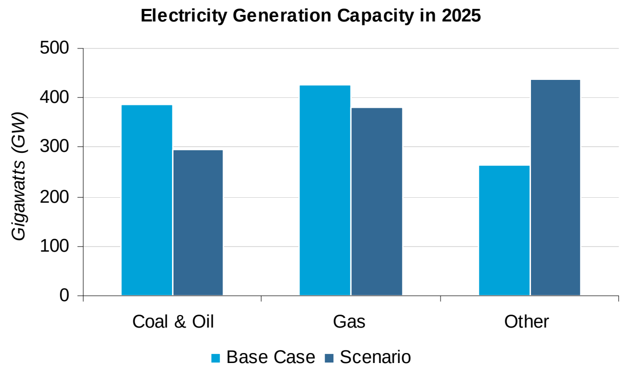










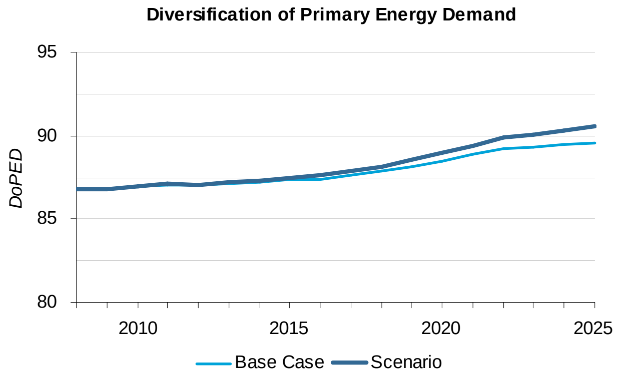


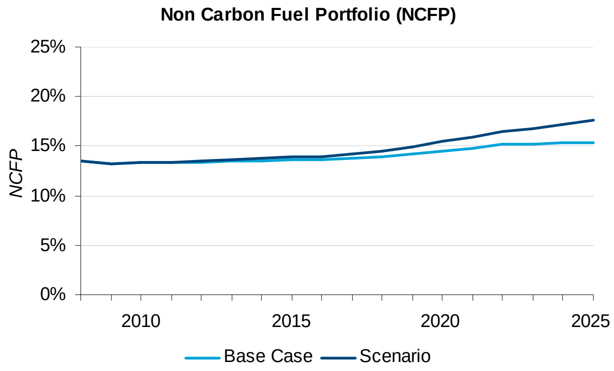
The US is a good example of how competition between fuel types may be impacted when introducing a substantial cost on carbon. The scenario projects a cost of $35 per tonne of CO_2 in line with current market projections where emissions' trading already exists.

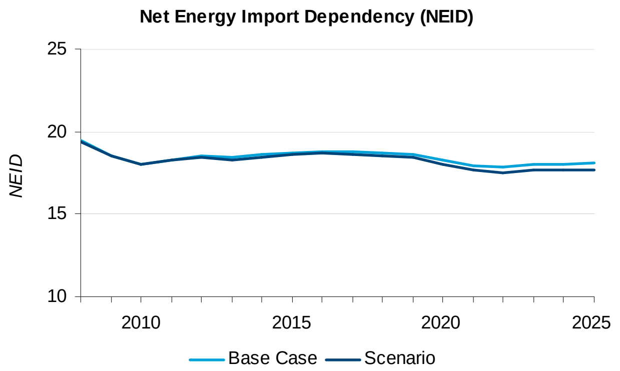
First, the cost of carbon will make nuclear and renewable energy viable options compared to fossil fuels. Hence, the scenario accommodates a gradual increase in wind energy towards 2025.

Second, at $35 per tonne it will make the full cost of coal and gas comparable, in which case local differences in supply, demand and pricing of the raw material will determine which fuel is chosen. Consequently, the increase in gas penetration in the US electricity sector is less than that what appears to be achievable based on current usage patterns, even with a reasonably high cost of carbon.

Energy security



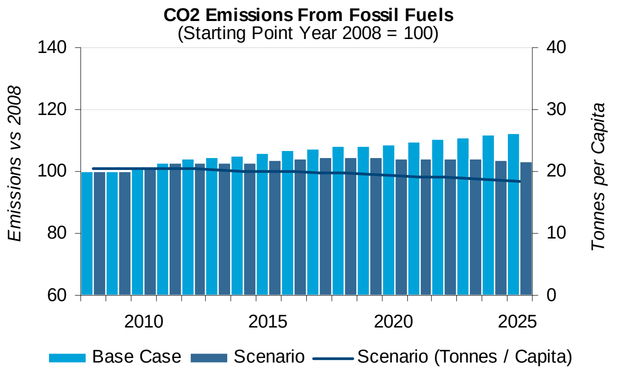


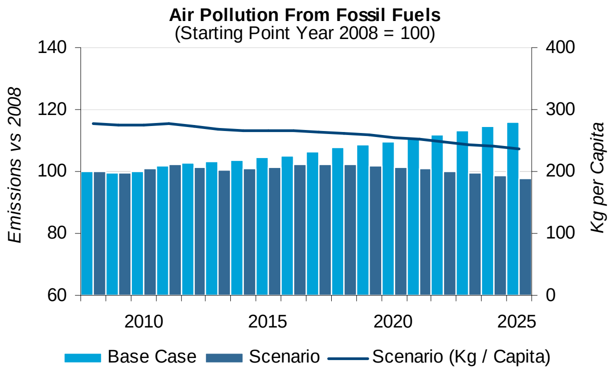


The positive developments for DoPED and NCFP are driven by increased use of renewable energy which means that the total primary energy demand is derived from five differing sources.

Net energy import dependency will be sensitive to the ability to maintain domestic gas production and whether oil consumption can be reduced.

Emissions and air pollution





The scenario shows a positive trend for both CO2 emissions and air pollution in the US, mainly caused by a switch to non-fossil fuel derived energy. Growth of gas instead of renewable energy will have a similar outcome (although to a lesser extent).

11.4 Modelling of economic growth

The objective of the economic modelling is to estimate the long term impact on the economy by increasing the utilisation of gas through fuel substitution.

Modelling was performed with the GTAP model managed by Monash University in Melbourne.[60]

GTAP is not integrated with the MARKAL model that was used for analysis of the energy markets, and hence there is not a direct relationship between input and output in the two models.

The long term economic impact is assessed by comparing 2025 results in the scenario relative to the base case which represents business as usual.

11.4.1 Assumptions

In order to assess the long term impact of increased gas penetration, the following groups of shocks were induced relative to the base case:

1. Investment in gas and disinvestment in coal, plus an exogenous switch from coal to gas in electricity generation.
2. An indirect tax increase on coal globally plus technological deterioration in coal mining.
3. Technological improvement in gas production.

Shock 1 – Investments in gas plus exogenous switch

The investment shocks only have a minor impact as the theory of the global GTAP CGE model does not in its present form allow for industry-specific investment. Rather, capital goods are perfectly mobile between sectors. Immobile factors, particularly in mining, are proxied by resource endowments. The model includes specific industry factors, but does not allow us to model the impacts of specific industry investments.

The exogenous switch from coal to gas in electricity production globally reduces the demand for coal and increases the demand for gas. The reason for an exogenous switch is to model a planned rather than price-induced switch in electricity. This planned switch can be initiated by governments in each of the respective countries.

The switch from coal to gas in isolation is expected to increase production costs, and will therefore have a negative effect on real GDP in regions in which the switch takes place.

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60 The appendices provide an overview of the GTAP model.

Shock 2 – Indirect tax on coal and technological deterioration in coal mining

Coal is the largest emitter of greenhouse gases per unit of energy and hence an indirect tax is imposed on coal rather than all fuels. A carbon tax in the GTAP model raises taxes on coal in all regions to around 50% of the producer price. India has a smaller tax increase than other regions, as the initial tax level is higher in the database than for other regions.

Disinvestment in coal mining results in a degree of technological deterioration in coal production. This reflects that there will be less emphasis on research and implementation of efficiency gains in the scenario than in the base case which represents business as usual.

In isolation, the effect is to raise the price of coal globally and improve the terms-of-trade of coal exporting countries such as Australia. However, the model allows for substitution by industries that use large amounts of fuel (electricity, petroleum and coal products, and mineral products). The substitution effect alleviates the impact on the terms-of-trade.

Shock 3 – Technological improvement in gas production

Technological improvement in gas production is the reverse effect of the technological deterioration for coal. It further induces substitution from coal towards gas by lowering the relative price of gas in industries in which substitution is possible. Australia has the largest technological gain in gas production in the scenario (30% relative to the base case).

The price-induced substitution between coal and gas, (shock 2 and 3) is expected to increase the utilisation of gas amongst major energy users.

11.4.2 Impact on gross domestic product (GDP) in 2025

Directionally, the economic modelling suggests that an increase in gas usage will have a modest positive impact on GDP in Australia and India, and a modest negative impact on GDP in the other countries.

The GDP impact for each of the three groups of shocks is discussed in turn below:

Shock 1 – Investments in gas plus exogenous switch

The investment and exogenous switch from coal to gas usage slightly lowers real GDP in all regions other than Canada as the fuel switch raises the costs of electricity generation relative to the base case. These results also reflect that in isolation, without considering the supply-side productivity impacts of shocks 2 and 3 below, the fuel switch will contribute to an increase in the price of gas relative to coal.

Shock 2 – Indirect tax on coal and technological deterioration in coal mining

An indirect tax on coal combined with productivity declines in coal production (relative to the base case) will have a negative impact on GDP in all regions.

Shock 3 – Technological improvement in gas production

Technological improvement in gas production relative to the base case has a positive impact on GDP in Australia, China, India and the US. The exceptions are Japan and Korea, where production of gas is virtually zero, and Canada, where gas production and consumption is similar in both the base case and the scenario.

Figure 11.1 Real GDP impact – Measured as % change relative to the 2025 base case

	Shock 1	Shock 2	Shock 3	Total impact
Australia	-0.102%	-0.222%	0.484%	0.160%
Canada	0.010%	-0.003%	-0.024%	-0.016%
China	-0.160%	-0.209%	0.046%	-0.323%
India	-0.099%	-0.013%	0.267%	0.155%
Japan	-0.004%	-0.008%	-0.003%	-0.014%
Korea	-0.023%	-0.014%	-0.002%	-0.038%
US	-0.062%	-0.165%	0.031%	-0.196%
Rest of World	-0.040%	-0.005%	0.019%	-0.027%

The 'total impact' is the sum of the three shocks. Percentage changes in GDP are measured for the scenario relative to the base case in 2025. For example, the table reflects that if Australia's GDP in the base case is 100, then GDP in the scenario will be 100.16.

11.4.3 Impact on aggregate consumption in 2025

The main difference between aggregate consumption and real GDP is the impact caused by changes in the terms-of-trade. That is, for a given level of national output or real GDP, if the terms-of-trade improve because the price of exports rises relative to the price of imports, then aggregate consumption as a share of real GDP will rise.

Figure 11.2 Aggregate consumption impact – Measured as % change relative to the 2025 base case

	Shock 1	Shock 2	Shock 3	Total impact
Australia	-0.084	-0.305	0.498	0.109
Canada	0.590	-0.023	-0.450	0.117
China	-0.324	-0.661	0.067	-0.918
India	-0.101	-0.043	0.285	0.142
Japan	-0.046	0.009	0.035	-0.002
Korea	-0.212	-0.109	0.145	-0.176
US	-0.128	-0.237	0.066	-0.300
Rest of World	-0.071	-0.028	0.042	-0.057

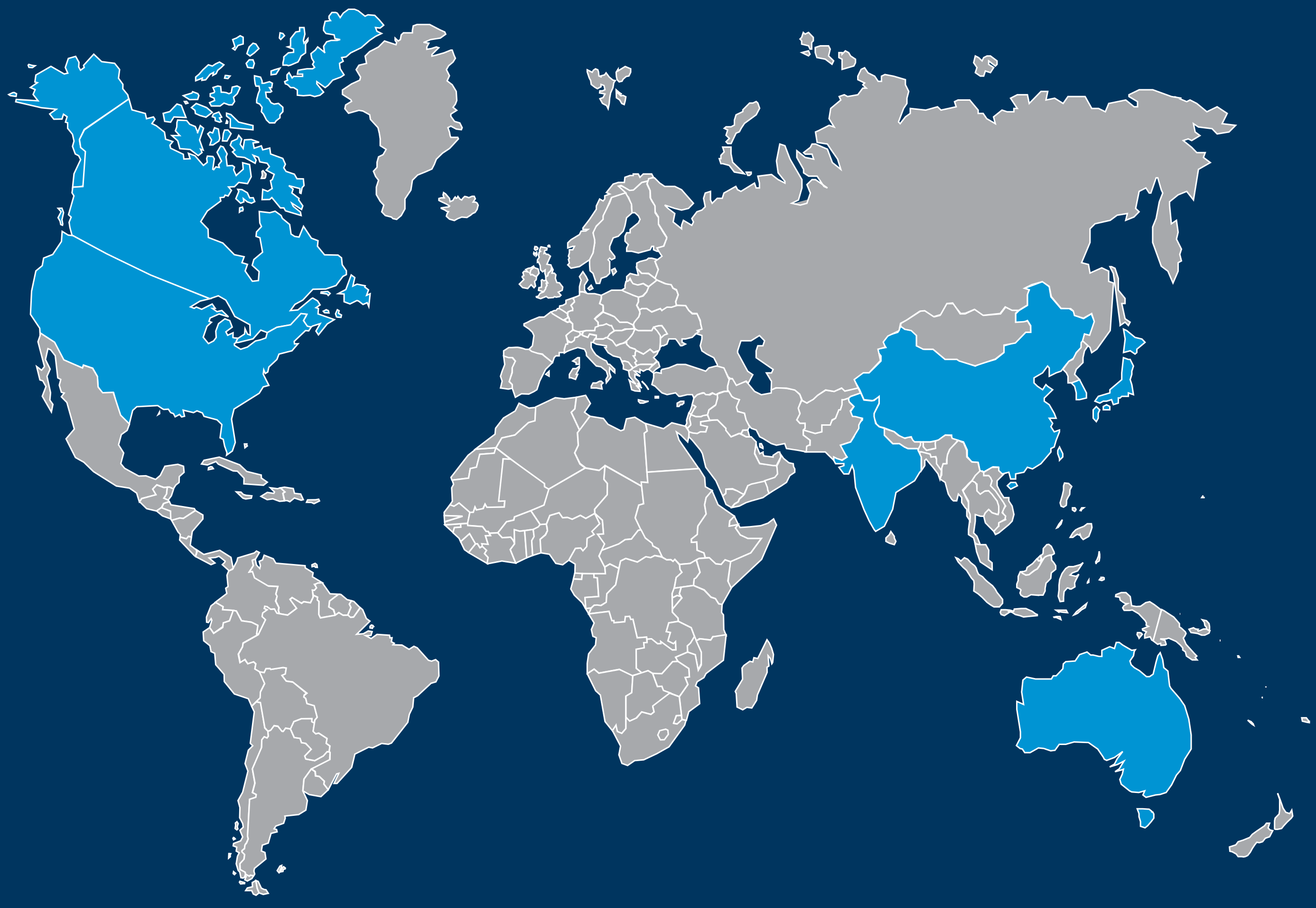
The impact on aggregate consumption broadly mirrors the impact on GDP. Directionally, the economic modelling suggests that an increase in gas usage will have a modest positive impact on aggregate consumption in Australia, India and Canada, and a modest negative impact on aggregate consumption in the other countries.

One difference between the results for GDP and aggregate consumption is the favourable impact on Canada. It is assumed that Canada does not have either significant productivity gains or losses relative to the base case. Since there is no accommodating supply switch, the demand switch shown for shock 1, in the table above, results in an increase in aggregate consumption. Canada has a substantial gas export base, several-fold larger in value terms than its coal export base. Hence, the effect of shock 1 which is negative for coal supply and demand, and good for gas prices, will suit Canada's export base.

The impact on China's aggregate consumption is negative as its terms of trade decline. The negative impact on export prices relative to import prices is caused by a combination of the indirect tax on coal and the higher import prices for gas.

PART D Findings and conclusions

Australia • Canada • China • India • Japan • Korea • US



12 Findings and conclusions

This section pulls together the information and analysis from all sections in this report to collectively develop findings and conclusions for the APP gas markets as a whole. The findings and conclusions are set out under the following:

1 Development of trade and market access in the APP

2 Significant global challenges, particularly as they relate to the supply side and its indirect impact on gas market growth in the APP countries

3 Modelling results of the APP gas markets

4 Country specific issues and impediments to gas market growth

5 Summary of impediments to gas market growth in the APP.

A high level summary of the findings and conclusions is provided in Section 12.6.

12.1 Development of trade and market access in the APP

APEC best practice principles

Asia-Pacific Economic Cooperation (APEC) is a forum for facilitating economic growth, cooperation, trade and investment in the Asia-Pacific region, six of the seven APP Partners have joined APEC.

The APEC Energy Working Group (EWG) has developed a set of best practice principles for facilitating and development of LNG trade and market access in the APEC region. These principles, which are detailed in Appendix A, are highly focussed on developing trading systems that facilitate free and open markets, flexible access arrangements, and investments. The principles also support coordination and sharing of information in relation to energy security, trade, technology and regulatory standards.

At the 6th meeting of APEC ministers in Manila in 2004, the ministers agreed that ”We support the creation of a competitive and transparent marketplace for gas trade and encourage member economies to move towards best practice as identified in ‘Facilitating the Development of LNG Trade in the APEC Region’, recognising the important contribution of the private sector in developing these principles, and direct the EWG to implement its recommendations …. “

Focus on markets and reducing barriers to investment

Consistent with the APEC best practice principles, and the objectives of the Asia-Pacific growth project, the focus in this report is to assess gas markets in the APP Partner economies with a view to identify areas where the Partners can reduce barriers to investment and encourage trade in the region. This approach reflects that:

- APP Partners have limited control over the supply side, and new supply to the APP will to a large extent rely on imports to the region in competition with increasing requirements for natural gas and LNG in Europe.
- Trade will not occur unless there is significant investment in infrastructure. A large proportion of these investments will come from the private sector (including corporations owned by or controlled by the respective APP governments).

It should be noted that it may not be possible or desirable for all countries to achieve highly efficient gas markets, and the need for sophisticated regulatory and competitive frameworks in the respective countries will evolve over time.

It is also important to note that development of efficient gas markets does not necessarily require privatisation of energy assets, particularly in the early stages of the process. In fact, the APP Partner economies and other countries assessed in this study predominantly have come from a position of government ownership of gas and electricity assets. The trend towards deregulation and/or privatisation has only gained significant momentum in the last 10-15 years. Hence, energy markets in these countries have had the benefit of long standing support and commitment from governments to build and maintain the infrastructure which currently underpins the markets. In addition, certain infrastructure assets in these gas markets have been granted exclusive rights in order to ensure that they are economically viable.

12.2 Significant global challenges

Many of the impediments to gas market growth in the APP Partner economies concern the supply side, and are specific to large-scale LNG projects outside the APP region. The global challenges are significant and their indirect impact on gas market growth is similar for each of the importing countries. The main issues are summarised in Figure 12.1 below:

Figure 12.1 Global challenges (supply side)

Category	Specific issues and risks
Complexity and risks of large scale projects	LNG projects are large and expensive to develop, and have a long lead time from inception to completion. Key challenges include: • High cost of upstream developments (offshore), construction and transport. • Availability of equity and project finance for large projects that are associated with substantial risk. • Availability of skilled resources to complete the planned projects. • Location, environmental and safety concerns.
The ability to provide security of supply	Gas and LNG producers must provide certainty of supply for end users. This is a key challenge for the supply side, individually and collectively, and the issues include: • Sovereign risk, concentration of supply sources, and the potential for a gas cartel to be established by Russia, Iran and Qatar. • The global marketplace, both physical and financial, being less developed than other commodity markets in terms of transparency and liquidity. • Limited ability to provide alternatives during unplanned supply disruptions, including insufficient availability of spot cargoes to manage variations in supply and demand. • Uncertainty of gas field development timing and production certainty.

These challenges are substantial, but it is reasonable to regard complexity and project risk as issues that can be overcome. In fact, good projects tend to find ways to move forward, and marginal projects are deferred or delayed until a time when economics, policy, fiscal terms, pricing or technology improves.

There are no significant trade barriers for natural gas and LNG trade, but project developers are required to manage a broad set of risks that extend far beyond the task of developing fields and transporting gas to end users.

Other factors, such as the price of gas or initiatives to address global warming, are important for the development of natural gas resources, but they are not necessarily barriers or impediments to growth. In fact, many of the key energy challenges today will benefit the gas industry rather than impede gas market growth.

The price of natural gas and LNG

High prices in recent years may have prompted some buyers to question the affordability of natural gas and LNG, However, this is not necessarily an impediment to gas market growth. Energy prices are determined by the market based on supply and demand at the time. There is a clear relationship between prices for the various types of fossil fuels as determined by their energy value.

In general, high energy prices will encourage the development of less traditional gas resources as evidenced by the shale gas, tight sand gas and coal seam gas developments in the US and Australia.

Price volatility creates uncertainty, but the link between international prices for oil and gas provides avenues to manage these market risks. For example, producers wishing to lock in high price levels for energy can access financial markets and hedging markets for oil, and this is the case for LNG supply contracts indexed to oil. Experience in the oil markets shows that some investors are in fact seeking out projects or companies that offer exposure to energy prices.

Initiatives to address global warming

Introducing carbon reduction measures such as an emission trading scheme or indirect tax to promote cleaner fuels may negatively impact the cost of making LNG. This is mainly because of the large amount of energy required to produce one unit of LNG. However, carbon reduction measures in general are positive for gas market growth relative to coal, so in the long run it is only reasonable to expect a consistent policy for emission reductions that apply for both producers and consumers of energy.

Conclusion – risk reduction will encourage investment and trade

Large-scale LNG supply projects carry substantial amounts of risk, and end users also expect reliable supply of natural gas and LNG. These are key issues for the supply side to manage.

The broader risks facing the supply side include the need for long term contracts to underpin investments, and a lack of certainty and commitment to gas market development in the importing countries. These risks are additional to the traditional project risks for large infrastructure developments, and will serve to discourage investment and trade in natural gas and LNG.

Governments in the importing countries can help reduce this risk by improving domestic gas markets to a point where stable and predictable government policies, regulation and end user demand provide certainty for investors rather than adding to the amount of risks. The implication and potential downside for countries with inefficient markets is that other destinations with less perceived risk will be preferred on a price parity basis. These important aspects of gas market growth are discussed further in Sections 12.4 – 12.5

12.3 Modelling of APP energy markets

The purpose in modelling the energy markets was to assess the impact of increasing gas use in the APP economies. Part C of the report outlines the impact on gas penetration, investments, energy security, greenhouse gas emissions, air pollution and economic growth for each of the seven APP Partners. The results in this section assess the aggregate impact of a positive gas market scenario against the business as usual base case.

The development of a scenario is intended to provide the means to quantify the impact of removing some of the key barriers to grow gas markets and gas market co-ordination in the APP. Results are provided below in aggregate for all countries.

It should be noted that although the scenario is designed to illustrate the impact of removing barriers to growth, it does not represent a maximum for gas penetration. For example, forecast investments in coal-fired generation are nearly double that of gas, so there is clearly the potential to shift further investments to gas. In addition, modelling of the US illustrates that an emission reduction scheme will not necessarily favour the gas industry, and that additional measures may be required to promote increased use of gas.

12.3.1 Gas penetration and investments

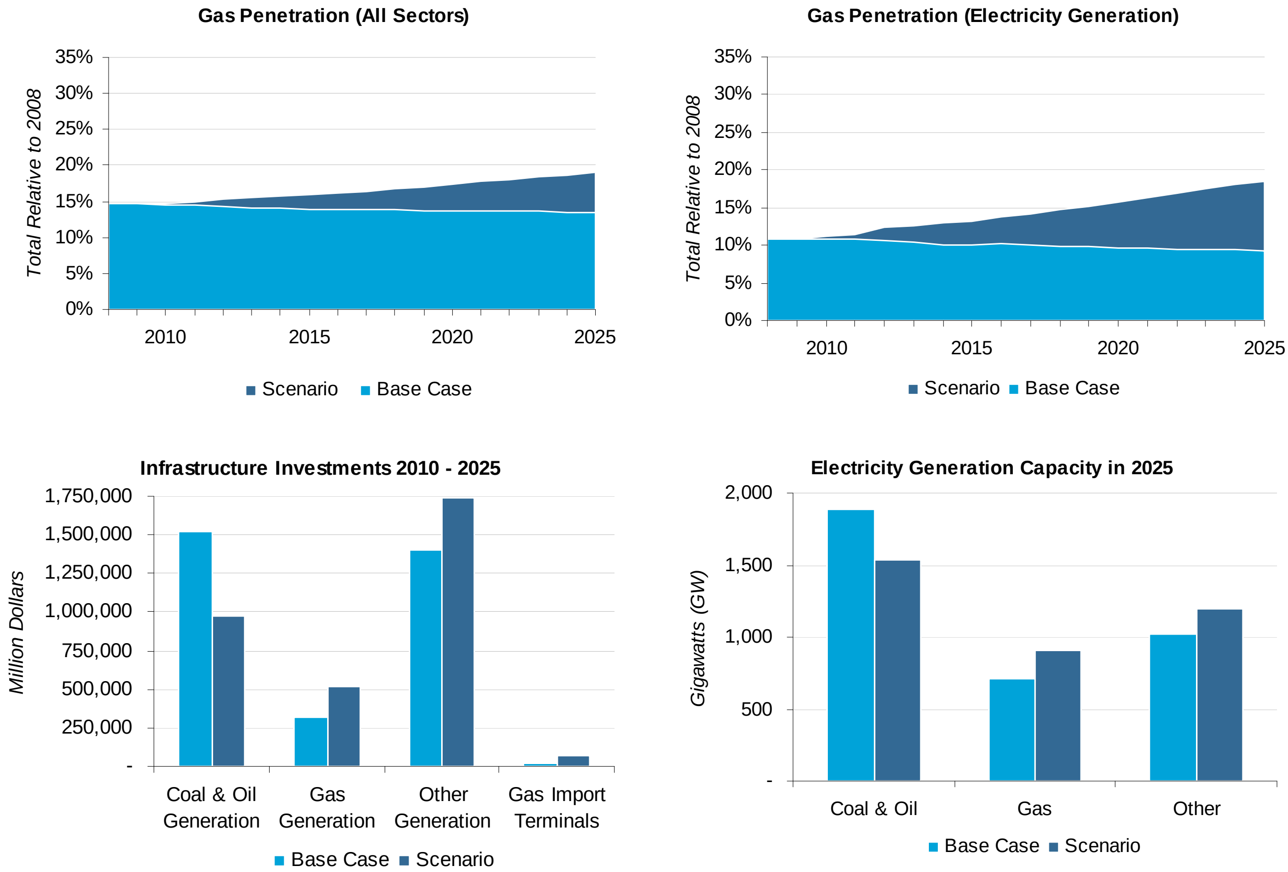
Gas currently represents 15% of the total primary energy supply in the APP countries, and the base case forecast is that gas' share will drop to 13% by 2025. Gas' share of electricity generation is forecast to decline from 11% at present to 9% at the end of the period.

The main reason for the lower gas penetration across the APP economies is that the strong growth in energy supply in China and India is weighted towards coal rather than gas. In addition, gas penetration in the US has been forecast to decline towards the end of the period.

China and India have the greatest potential to increase gas as part of the energy mix. This is due to a combination of low gas penetration at present and plans to make large investments in new electricity generation capacity. Also Australia, the US and Korea have good potential to grow gas consumption relative to the base case. Canada's base case already incorporates gas market growth, and the short term opportunities are quite limited in Japan.

Gas usage in the scenario increases from 15% to 19% of the total primary energy supply, and gas' share of electricity generation output grows from 11% to 19%. The increase gas penetration scenario is achieved through a combination of carbon reduction schemes in the developed economies (ie carbon trading or carbon tax) and a policy shift towards gas in the developing countries. The results and comparison of a business as usual base case and a scenario that increases gas penetration is displayed in Figure 12.2.

Figure 12.2 Gas penetration and investments



The modelling also revealed that carbon emission reduction schemes will not just benefit gas-fired electricity generation. A high cost on carbon may deliver the following:

- Nuclear energy is reinforced as the cheapest option for electricity generation.
- Wind energy becomes cheaper than both gas and coal. An expected focus on improving technology and cost reduction may in turn deliver new commercial alternatives from renewable sources.
- Coal prices will most likely be set to compete with gas. This is possible because coal is readily available at a low cost in many countries, including Australia, China and the US. High prices for oil and gas will also continue to favour coal.

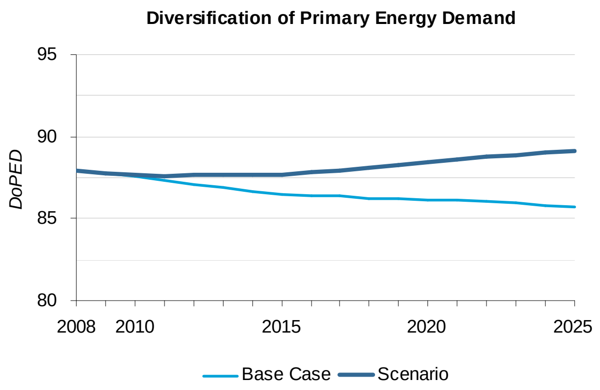
Gas has many benefits compared to coal, including significantly lower levels of air pollution. Consequently, if the aim is to reduce reliance on coal worldwide, an emission reduction scheme for carbon may work best in combination with a pollution reduction scheme and/or more targeted initiatives to achieve the desired outcome.

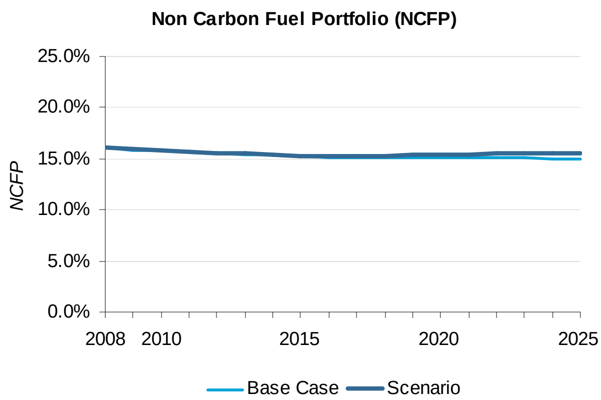
Total investments in electricity generation capacity and gas import facilities could exceed $3,200 billion between 2010 and 2025, so this is clearly the key focus area for gas market growth. Nearly half of the investments (47%) are expected to be in coal fired generation.

Our modelling shows that investments in coal plants can be reduced from $1,525 billion (47%) in the base case to $975 billion (29%) in the scenario. This would allow investments in gas-fired generation to increase from 10% to 16% of the total, and investments in other generation (nuclear, renewable and hydro) to increase from 43% to 54%.

Investments in LNG import facilities represent 0.5% of total investments in the base case, and 2% in the scenario.

12.3.2 Energy security

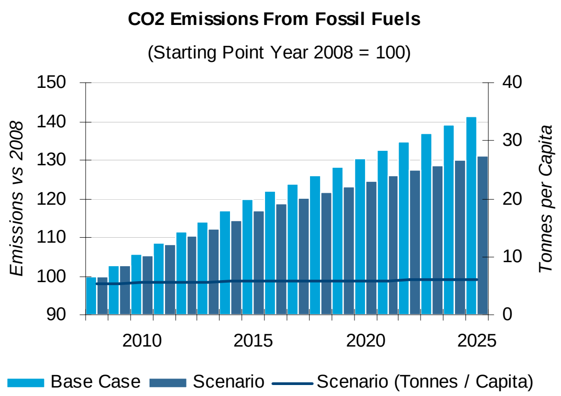


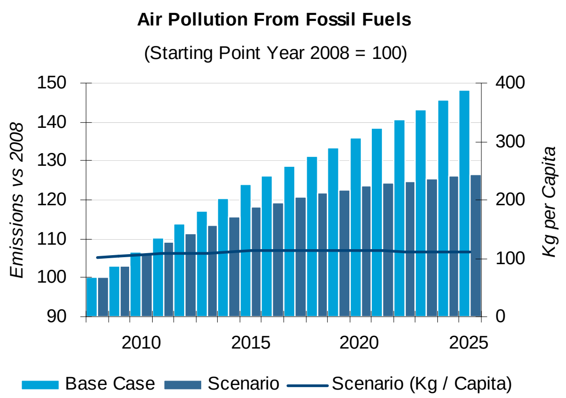


Diversification of primary energy demand which is a key measure of energy security shows a positive trend throughout the period as the reliance on coal is reduced from 42% in the 2025 base case to 35% in the scenario. This reduction in coal is matched by an increase in gas.

The share of non-carbon fuel in the portfolio remains fairly constant throughout the period, consistent with the modelling assumptions. However, policy decisions to implement a high cost on carbon could see changes in this area.

12.3.3 Greenhouse gas emissions and air pollution





The base case forecast is that CO_2 emissions and air pollution from burning fossil fuels will increase respectively by 41% and 48% compared to 2008. The increase reflects that energy usage is expected to grow by 35%, and that the reliance on coal is forecast to increase throughout the period. Based on these numbers one would expect the potential for improvements through demand management and a shift to cleaner fuels to be considerable.

The high gas penetration scenario shows a 7% reduction of CO_2 emissions compared to the base case, and a 15% reduction in air pollution (measured as the total of nitrogen oxides, sulphur dioxide and particulates).

12.3.4 Economic growth

Impact on gross domestic product in 2025

Economic modelling shows a modest gross domestic product reduction in the scenario compared to the base case for all countries except Australia and India. These results reflect the combined impact of higher gas prices relative to coal, technological deterioration in coal mining and technological improvement in gas production.

Australia, Canada and India also have a modest positive impact on aggregate consumption as the terms of trade improve when export prices rise relative to imports.

Long term economic impact (beyond 2025)

Some of the most significant benefits of increasing gas use in the APP have not been modelled because the positive impact on the economy and the environment will only be evident after the end of the modelling period.

Specifically, reducing the level of CO_2 emissions and air pollution over the next 15 years will have a positive impact on the economy beyond 2025. Therefore, the overall long term impact of higher gas use in the APP can be assumed to be positive, provided that the higher cost of energy is consistent with a market based cost of emissions that fully reflects their negative impact on the environment.

12.3.5 Country summary

The favourable impact on the APP Partners in aggregate reflects that there are favourable outcomes for each of the member economies.

Figure 12.3 summarises the results for each of the measures of energy security, air pollution and economic growth that were modelled and presented in Part C of the report (nine measures in total). The favourable results are confirmed by showing results for each country as well as the totals.

Figure 12.3 Scenario outcomes in 2025 compared to base case (by country)

+1 Favourable impact   -1 Unfavourable impact   - Neutral

	Australia	Canada	China	India	Japan	Korea	US	APP7
Energy security								+6
• Diversification of primary energy demand	+1	-	+1	+1	-	-1	+1	
• Non-carbon fuel portfolio	+1	-	-	+1	-	-	+1	
• Net energy import dependency	+1	-	-1	-1	-	+1	-	
CO2 emissions	+1	-	+1	+1	+1	+1	+1	+6
Air pollution	+1	-	+1	+1	+1	+1	+1	+6
Economic growth in 2025								-4
• GDP	+1	-1	-1	+1	-1	-1	-1	
• Aggregate consumption	+1	+1	-1	+1	-1	-1	-1	
Total impact	+7	-	-	+5	-	-	+2	14

Although Figure 12.3 does not measure the size of benefits or costs, it confirms that the impact of gas market growth is positive for energy security, CO2 emissions and air pollution.

In addition, when incorporating the full impact on economic growth beyond 2025, including the long term benefits achieved by making a positive contribution to reducing global warming, the total benefits of higher gas use will increase further.

12.4 Country specific issues and impediments to growth

12.4.1 Australia

Australia is rich in energy resources and as such has not been too concerned with energy security. In recent years Australians have become very concerned with the effects of climate change and the new government that was elected in 2007 has ratified the Kyoto Protocol and announced the introduction of an emissions trading scheme, which is officially referred to as the Carbon Pollution Reduction Scheme (CPRS).

The outlook for the Australian gas industry as a whole is very positive with prospects of strong domestic and international demand. The main opportunities for gas producers in Australia are in the export of LNG, but a well implemented emission trading scheme that encourages the use of gas would also present development opportunities for the domestic gas industry.

We analyse below the key impediments to growing the gas market in Australia and offer possible solutions consistent with APEC's best practice principles to facilitate the development of gas markets.

Energy policy – Value of CO2 emissions

The competitive price of coal for power generation, and the state governments' support of the coal based industries are key issues for the development of the gas industry in Australia. This is a problem common to many countries and in Australia's case it is more poignant as coal is an important economic driver and the main source of electricity generation in the country (around 80%).

Australians are high energy consumers. Among the APP countries Australia is at the top of the list for per capita CO2 emissions, which is driven by high use of coal and oil.

Possible solution – CPRS and pollution

When discussing energy policy and energy security issues, Australia should continue to assess the risk of having such a high reliance on one particular type of fuel. Ideally, the energy mix could be more balanced and gas could have a much higher penetration as Australia is a large producer. Government support for gas will ensure industry growth and attract investment.

The implementation of the Carbon Pollution Reduction Scheme will be a key challenge for the Australian government as it has several ramifications, especially with coal which is readily available and also a major source of revenue and employment. The proposed CPRS in combination with penalties for non-CO2 pollution will have a positive effect on gas generation.

If gas prices rise in Australia (possibly driven by new LNG projects on the east coast that will establish a link between domestic and international prices), the gas generation sector might be unable to compete with inexpensive coal. The broader plan for managing climate change could have a mechanism for dealing with this possibility.

Policy and regulatory issues

The regulatory framework is well set up and Australia has a stable legal environment. However regulatory decision-making is not always perceived to be consistent and the regulatory processes are time consuming. The strong focus on consultation is a positive aspect of the process. However, too much consultation may also result in failures to adhere to stipulated timelines, which in turn can be frustrating for investors.

There are frequent rule changes and the industry undergoes constant restructure. The decisions to allow transmission networks to acquire distribution networks, and determination of their relative returns, may not have been easy to predict. Several regulatory decisions have been supported by confidential undertakings between the regulator and energy companies.

Regulation can act as a barrier to the development of economically viable projects if these are stalled due to lengthy approval processes and lack of coordination between the states. This will be particularly important when dealing with LNG facilities.

A generally accepted principle is that processes are clear, transparent, non-discriminatory, co-ordinated and timely. The regulators and the government are expected to provide justifications for decisions and should work at adhering to timeframes.

Possible solution – Improved coordination

The governments should continue to search for the right balance between taking the necessary time to asses a project and encouraging investment. Careful consideration should be given to time management in a high-capital investment environment.

Decisions made by the regulators should be coordinated. Dealing with consistency is extremely complex but interstate coordination would reduce issues relating to differences of opinion between the states. The states could co-ordinate and agree on the basic principles in order to accelerate processes, particularly when multiple jurisdictions are involved.

Greater coordination will also have a positive impact on timeliness.

Infrastructure issues

Australia's existing infrastructure is appropriate for the current demand. If demand increases to the levels expected, a key challenge will be to upgrade existing infrastructure. The key issues around infrastructure at present relate to pipeline capacity utilisation and storage, which can also cause market power.

Possible solution – Utilise/increase capacity

Australia has a legal and regulatory framework in place that will encourage investment to be made as demand increases. A key role of the regulator and market operator is to point out the opportunities and facilitate the investment processes.

With short-term trading markets starting up on the east coast, storage facilities, short term capacity availability or additional pipeline capacity in those states may assist in meeting high peak demand and managing short-term trading risk. The step change in demand for infrastructure will occur with substantial investments in gas fired electricity generation.

Gas market structure and operation

Under the current market structure and operation it is not easy for businesses to manage their financial risk and security of supply. There is no secondary market. This increases the need to secure long-term bilateral contracts. Gas sales that are largely based on long-term bilateral contracts for the commodity and transportation have resulted in:

- Constraints on infrastructure capacity utilisation.
- Lack of price transparency.
- Lack of responsiveness to a transparent electricity market.

These issues can create 'market power' and prevent new players from entering the industry. As a result there are very few retailers in gas. The fully contracted pipeline capacity acts as a barrier for new entrants as they cannot get reasonable access to a pipeline that is already fully contracted, even if it is considerably underutilised.

Possible solution – consistent short-term trading mechanisms

There is a very positive move to create short-term trading markets on the east coast, which will encourage competition and transparency. Australia should continue to seek the development of a flexible trading system that is integrated and includes:

- Short-term/spot trade.
- The capacity to develop a forward market for gas.
- The removal of unnecessarily restrictive contractual practices.
- Further transparency in pipeline capacity availability.

Demand management

Demand management is a new concept in Australia. The government has started studies around demand management with a focus on electricity savings.

Compared with other countries, Australians are used to low energy prices and there is lack of public awareness of the advantages of using certain appliances. For example, hot water provided by an efficient gas hot water system may have environmental benefits compared to an electric system which is 80% fuelled by coal and subject to substantial energy losses during transmission.

Possible solution – Public education

Demand management initiatives in Australia could include the promotion of gas over electricity for certain energy requirements. Direct use of gas in home heating and hot water systems, or indirect uses such as cogeneration, can improve Australia's economic and environmental performance.

Australia could also undertake public education campaigns by highlighting the benefits of using energy efficient appliances. This may be complemented by promotion of natural gas and emphasising its economic, environmental and energy security benefits.

Other risks

Australia remains relatively unexplored. Offshore exploration and development costs are very high so exploration businesses will lobby for tax incentives and exemption from the CPRS to make some projects viable. Australia's size ensures that exploration and production opportunities will continue to arise, but there are also constraints (including labour and technology) for how quickly the country's resources can be developed.

12.4.2 Canada

The North American market will continue to benefit from the significant ongoing investment in North American natural gas supply and delivery infrastructure. Increasingly unconventional and remote supply sources, expanded storage capacity and improved end-use efficiency will all help to guarantee supply.

The gas industry is large and efficient in Canada, which implies that most of the impediments to growth have already been removed. Further growth in the gas industry will mainly be limited by Canadian gas price competitiveness and the key challenge will be to find new sources of natural gas.

Our discussion will centre on regulatory and policy issues.

Regulatory and policy issues

Long pipelines require numerous authorisations as they can overlap jurisdictions. Having multiple jurisdictions to continually deal with could deter investors. Where jurisdictions overlap, the NEB is working with provincial and territorial regulatory agencies to ensure the environmental assessment and regulatory issues are dealt with in a coordinated manner.

Whilst the interconnection with the US is beneficial to both countries, it does not account for different rates of return and risks within the regulated pipeline sectors in each country. This affects competition for business investment between the two countries.

Historically there has been competition between the provinces of Alberta and British Columbia to sell gas to the US. This has generated a lack of cooperation between the states. Streamlined regulatory processes with a single location for all administrative approvals would be beneficial but it will only be possible if there is close cooperation between federal, provincial and territorial governments.

Lack of infrastructure also limits access to gas as more infrastructure would need to be developed in order to access reserves in some areas like Northern Canada and offshore. In other instances, environmental concerns and regulatory processes around gas exploration and production limit access to gas. Often, these concerns can be exaggerated and represent impediments to increase Canadian gas production.

Possible solution – Improve coordination

- Reliance on lengthy processes for approval of new pipelines should be kept to a minimum as investors are put off at the idea of waiting for approvals. This could be improved by using a single location for all administrative approvals.
- The provinces could cooperate in order to achieve better results that would benefit all parties, for instance in the case of British Columbia and Alberta selling gas to the US.

12.4.3 China

Production, consumption, exports and deliverability for natural gas have increased significantly in recent years, due to regulatory pricing that has made natural gas artificially cheaper, increased attention to environmental issues as well as major investment in the west-to-east transmission network.

The Chinese government is keen to reduce its dependence on coal as a fuel source for power generation due to the high levels of pollution it causes in major population centres. As part of the government's approach to tackle pollution it wants to promote 'cleaner' electrical power through gas-fired generation, renewable energy and nuclear energy. Therefore, it has been increasing gas exploration efforts, pushing forward construction of the Central Asia and West-East Gas Pipeline, as well as LNG re-gasification terminals. Despite these measures, coal is likely to remain the primary feedstock fuel for generators for some time to come due to large domestic reserves and its competitive pricing relative to other fuels and power generation technology costs.

In order to satisfy its huge demand for natural gas, China will rely on increased natural gas production and LNG imports, the promising development of coal bed methane (CBM) and considerable investments in pipeline infrastructure.

The analysis below concentrates on the main impediments for the growth of gas markets in China.

Energy policy – Value of CO2 emissions

Coal

Coal is the backbone of China's energy system meeting over 60% of the primary energy demand and growing. The domestic coal production is significant, China being the 2nd largest producer in the world. The main use of coal is for electricity generation, with over 80% of it being coal based. Coal fired generation is expected to increase at an average rate of 4.9% pa.

As a developing country, China does not have an emissions reduction target as a signatory under the Kyoto protocol.

Infrastructure issues

Overall natural gas supply, pipeline networks and gas storage are in shortage. The growth of China's natural gas market has been limited by supply deliverability capacity. A considerable investment in pipeline and storage infrastructure is required. This is exacerbated by the fact that production will be increasingly concentrated in the centre and west of the country while demand is concentrated in the southern and eastern provinces.

Pipelines

CNPC aims to build a well-connected national trunk pipeline network but this will take time. The distribution networks in China are under developed. Many cities lack an appropriate distribution network to transport gas and would require major investment to meet future demand.

Storage

Downstream players with higher gas requirements are actively seeking ways to diversify supply sources and build supply buffers.

Insufficient gas storage provides limited protection for downstream management of supply/demand imbalances. Government's regulatory role in storage requirements is not well-developed.

Government plays a minimal regulatory role in gas storage requirements. No strategic reserve requirements are in place yet and current storage is insufficient.

Pricing issues

Wholesale prices

Government regulates natural gas prices which are artificially kept low. Low prices do not provide enough incentives for private/foreign companies to invest in the upstream and transportation segments of the gas supply chain. In December 2005, the NDRC issued a new directive to establish a market-oriented price mechanism in the gas industry. However, delivered gas price is still set by the NDRC in the major consumption centres.

Natural gas development is hindered by inefficient pricing and it takes time to develop coal seam gas, LNG and long distance pipeline gas import projects.

In absolute terms coal is the most heavily subsidised form of energy. In percentage terms, under-pricing is biggest for natural gas and coking coal. On average consumers pay a little over a half the true economic value of the gas they use.

Price setting remains a sensitive issue and subsidies remain large in some cases, albeit in an effort to achieve important policy goals.

Pipeline tariffs

The tariff system is quite simplistic despite certain improvements. Tariffs do not encourage optimised use of natural gas. The new 'two-step' tariff system to encourage greater pipeline efficiency is being adopted slowly.

There are no stand-alone tariffs and commercial operation of storage facilities. Costs of storage investments are usually factored into the pipeline transmission tariff.

Policy and regulatory issues

Transparency

The lack of transparency in regulations continues to constrain midstream asset development. NDRC is under-manned and has not been proactively managing the growth but rather letting the market develop itself, giving rise to a situation where gas upstream controls and dictates midstream opportunities.

Foreign investment restrictions

Government policies in the natural gas sector limit foreign investment. While foreign investment is 'encouraged' in midstream activities by NDRC policy, no further guidelines are provided and projects are still approved on a case-by-case basis, leaving much room for market power manipulation.

NDRC generally allows a 12% rate of return for midstream projects and PetroChina's midstream operations are therefore very profitable. However, future midstream project economics are hard to predict because there is a lack of a benchmark besides PetroChina.

Lack of access to infrastructure

Third-party access to midstream assets is still being discussed as part of draft energy law. Sinopec's sharing of PetroChina's pipeline is again negotiated on an ad-hoc basis.

Market power

CNPC, Sinopec and CNOOC control the upstream and midstream market, with CNPC dominating the on-shore sector. The three companies account for 95% of total gas supply (production and imports). Competition within the gas sector is primarily between China's the three NOCs who have used their marketing freedom to sell gas to industrial consumers (particularly in the chemical industry) who can purchase more feedstock than the state utility companies, whose resources are limited by state capped retail prices.[61]

Equity participation of IOCs is limited in the on-shore development areas.

Local distribution companies for pipeline reticulated cities have limited choice for purchasing gas, often only having a single choice from the three large gas companies to service their residential and commercial customers.

12.4.4 India

There is significant potential for India to increase energy supply to its industries and households in light of the current low per capita consumption and forecasted economic growth. During the course of this project consultation with stakeholders revealed an insatiable demand for reasonably priced energy from electricity, gas or coal.

The government has been trying to balance the following issues of growth, equity and energy security:

- Growth: by opening up markets, designing investor-friendly policies and deregulating economic activity.
- Equity and energy security: by ensuring government control over public enterprises involved in energy distribution, and by providing subsidies to the poor to enable affordability.

However, there is a growing perception in the industry that increased efficiencies can be obtained through a market mechanism which is adequately regulated. Gas market regulations are still at an early stage of evolution. The current regulatory framework is focused more on gas transmission and distribution, and less on gas pricing and marketing.

Overall, the Indian gas market has enormous potential for growth. The challenge for the government is to design effective policies that encourage investment in infrastructure, and to ensure the price difference between coal generated electricity and gas does not impede infrastructure investment and market development. Growth in India will be driven by:

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[61] Global Insight Inc. 2008

Energy demand on account of economic growth and improved standard of living	India is witnessing high growth in energy demand in line with economic growth. Gas availability is limited to certain industrial pockets so many of the industries use costlier electricity from coal. The increasing availability of energy will itself lead to growth. A reasonably priced and assured supply of a clean fuel like LNG would definitely help India realise higher economic value in the booming economy, while increasing energy supply diversity.
Access to commercial energy	A large part of the population does not have access to reasonably priced and commercially available energy. Rural households use fuels like firewood, biomass or subsidised kerosene for domestic needs due to the lack of other energy fuels. This indicates the opportunity for investment in the downstream sector. The national government policy now focuses on promoting city gas networks, using natural gas for public transport, buses and taxis etc.
Huge growth in electricity generation capacity	India has plans to double the existing generation capacity to provide electricity access to 100% of the population and promote industrial growth. A significant part of the new generation could be based on natural gas or LNG. India currently has around 170,000 MW of installed capacity and this is proposed to become 212,000 MW by 2012.
LNG for a diversified energy mix	Being dependent on imports, energy security will remain an area of priority for the government. Promoting LNG could be one way of ensuring a diversified energy mix.
Moving towards a clean-energy economy	The increasing global focus on greenhouse gas reduction will lead to pressure on India to pursue cleaner fuels.

Policy and regulatory issues

The government has been taking firm steps towards promoting an open market for gas and new regulations for the sector are being enacted. A move toward transparent regulations and a level playing field for new players could result in a more efficient gas supply chain, thereby powering economic growth and improving the standard of living of people deprived of commercial energy.

Possible solution – Implementing new regulations

A stable regulatory regime and consistent policies would encourage more investors to participate in the development of gas markets.

The new regulations in the natural gas sector regarding pipeline investments, LNG infrastructure and city gas investments are focused toward a transparent regulatory regime to ensure fair returns for investors. Also, the subsidies affecting gas market pricing, including fertiliser prices and power tariffs, could be rationalised to better reflect economic costs.

The diverse nature of the Indian economy and the issues of poverty and inclusive growth are unique to the country. But while setting policies to address these issues, India could absorb the experiences of other countries which have undergone similar transformations. World's best practices in utility and energy regulations can provide a guide to develop an optimal policy framework that meets the country's twin objectives of growth and economic equity.

Independent regulator and regulatory capacity building

Regulations are still taking shape and new legislation to promote markets has been enacted. There will be great benefits from prioritising a speedy process for moving towards a transparent regulatory regime. The PNGRB would be critical to the processes of reform and to establish sufficient capacity building and adoption of best practices to ensure a vibrant gas economy.

Pricing distortions issues

Different pricing mechanisms apply for different sectors and sellers in India.[62] In summary:

- The government decides on the price of natural gas for the electricity generation, fertiliser and city gas distribution sectors.
- The gas produced by joint venture and private players is priced at market rates.
- LPG (the main domestic fuel) is heavily subsidised for domestic consumers.

The distortions are a result of the national priority to provide affordable domestic energy to the population (electricity and LPG) and also to subsidise the fertiliser costs (since a large percentage of population is dependent on agriculture for income). Pricing distortions make it difficult to select one fuel over another, and create inefficiencies in the market by diverting subsidised fuel for commercial use.

Possible solution – Move towards free and open commodity pricing

India would greatly benefit from the development of a spot market for gas with transparent pricing. As can be learned from international experience, trade promotes investments. The emergence of a spot market is not an easy step and it may develop over several years. The first step required is to let the market set the wholesale price without government intervention.

In order to achieve this, price unbundling is critical. India has entertained the possibility of unbundling GAIL to encourage competition and ensure transparency in transportation costs.

While a sudden move to unbundled markets would result in equity issues, the government could enable a market-led price discovery, starting with commercial and industrial customers.

Market based pricing will depend on a clear policy and timeline for elimination of subsidies and cross subsidies. India currently has a subsidy system where all users benefit irrespective of the ability to pay for the service. A targeted subsidy system would accelerate a move toward a market based on economic principles.

It is common practice that governments regulate gas transportation and storage as they are natural monopolies (and also retail prices in some instances) in order to protect small customers. Therefore the establishment of the regulatory board and the new regulations based on economic principles have been a step in the right direction. Further benefits will follow from consistency in pricing reforms in the downstream sector.

[62] Natural Gas Markets in APP Countries with a Special Focus on India and China: Regulatory Issues, Cross-Border trade, and Evolving LNG Contract Structures

Infrastructure issues

Lack of adequate infrastructure is the biggest challenge for the development of gas markets in India. Much of the transmission system is concentrated in the natural gas production centres, and there is little interconnection between regions.

GAIL has announced an ambitious long-term plan to increase its transmission network from 1,900 miles to 6,200 miles thereby establishing a national gas grid. However, only a handful of actual expansion projects are planned for the next few years.

Possible solution – Infrastructure planning

Analysis suggests that India could benefit from strengthening its focus on infrastructure planning. Due to a lack of clear policy on the trajectory of infrastructure building, new players would feel uncertainty and withhold investment. A policy would clarify the requirements for appropriate planning, outline the longer term commitment to gas and encourage private sector investment.

In spite of the government's willingness to open the market to new players, investment in infrastructure has been slow. This could be attributed to uncertain downstream pricing and uncertainty about the long term commitment to gas.

Pipeline infrastructure is a natural monopoly and in most countries it is subject to regulation. An integrated network is ideal as it connects the markets and is a way to improve supply management.

Regarding access to infrastructure, it will be very important to plan the market structure around GAIL. Separation of the infrastructure and retail arms of GAIL will be beneficial and the outsourcing of the retail arm of GAIL will encourage retail competition. Development of GAIL's infrastructure in a planned and integrated manner will be essential for future growth, and competition will increase once third party access is ensured.

Very importantly, LNG terminals will need a pipeline to link them to the demand centres. Without adequate pipeline infrastructure LNG investments will also be on hold.

Energy policy – Value of CO2 emissions

India's energy mix is currently dominated by coal and oil, although the role of natural gas has been rapidly increasing. The presence of non-commercial fuels (firewood, biomass, charcoal) in the household sector and the fact that 70 million households use subsidised liquefied petroleum gas or kerosene for cooking indicates great scope for potential gas penetration.[63]

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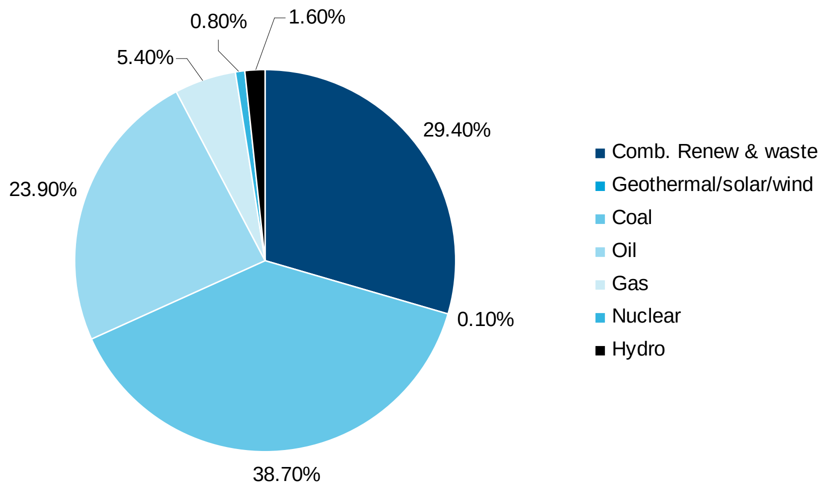
[63] International energy initiative: http://iei-asia.org/IEIBLR-Cleancooking-Presentation.pdf

Figure 12.4 India's total primary energy supply in 2005



India is the third-largest consumer of coal in the world. It also has substantial coal reserves, meaning coal is a cheap and attractive fuel. 53% of India's power generation capacity is coal-based (gas accounts for 11%). In the absence of an emission trading system and firm policy support for gas, coal will continue to be preferred over gas.

Possible solution – Moving towards a carbon pricing system

India is not an 'obligated' country under the Kyoto Protocol, and has not enacted any policies to move toward cleaner fuels (except the introduction of CNG-based public transport in some big cities). This means that energy prices do not reflect the cost to the environment. New policy measures could clarify the balance between growth in energy supply, the need for cheap energy and control of emissions.

Despite having some way to go in providing reasonably priced energy to its vast population, India could benefit from planning a gradual transformation to cleaner energy sources over time. This would require early policy interventions and debate on how to deal with carbon emissions. India has been experimenting with mandatory renewable targets in some areas such as retail purchases, and setting policies for enabling investments in renewable generation. However carbon emissions affect all aspects of the energy policy.

Other risks

Community opposition

Many times government policies have been backtracked due to heavy opposition and demonstrations. Energy prices are politically sensitive as there is a large population depending on government subsidies for cooking-gas (LPG), fertiliser and electricity. Therefore any pricing reform would be slow, and there will not be a level playing field for private/gas utilities for some time to come.

Gas market structure

At present the market is controlled by a small number of companies with an effective monopoly of gas infrastructure provision. A high degree of public ownership inevitably causes political intervention. There is also a degree of vertical integration with GAIL being in charge of all downstream activities.

12.4.5 Japan

Japan is one of the world's top five energy consumers. It has limited availability of energy resources and has an environment that makes infrastructure integration difficult. It is hardly surprising then that the Japanese government has energy security as a top priority.

Natural gas plays a significant role in the development of Japan's energy policy and its use will increase as tighter controls are put in place following the government's commitment to achieving greenhouse gas emission targets.

Japan has promoted diversification of energy sources after the oil crisis in the 1970s. Both LNG and nuclear energy are considered to be reliable base-load power sources that will contribute to energy diversification and mitigation of climate change. The government's desire to increase the use of nuclear power will need public support from the populace that is concerned with safety and the potential for earthquake damage to nuclear power plants.

The outlook for the Japanese gas industry looks positive with ongoing market reforms encouraging competition and investment. Stable growth in gas is going to be further supported by:

- Japan's commitment to clean energy and environment protection.
- Energy security concerns, as Japan is looking at reducing reliance on oil.
- Industry reform that is seeking to improve infrastructure and interconnection between the different markets.
- Technology developments that will increase the number of uses for gas.

Energy Policy and CO2 emissions

Coal is one of the major sources of electricity generation in Japan, due to its relative low cost and its contribution to energy security. Being one of the largest energy consumers in the world Japan is concerned with reducing its CO2 emissions. Japan is a world leader in progressing energy and environmental policy, and the country is committed to guiding the world's economies along a sustainable and secure energy pathway.

Japan regards energy conservation as a means for simultaneously solving issues in relation to energy security and climate change. To achieve high energy efficiency, the country has strong energy and climate change policies such as the Energy Conservation Law.

Possible solution – Value of CO2 emissions

As per the IEA Japan 2008 study, Japan's leadership and commitment to climate change and global action for the long term is an example to follow.

Japan could benefit from further encouraging market signals in the economy by providing incentives for reducing greenhouse gas emissions. This can be implemented in a way that promotes demand for gas, both at the industry level and at the power generation level.

Regulatory issues

Japan's primary competition regulator the FTC has recently been strengthened in terms of resources but the FTC continues to be perceived as another arm of government. While independent from the government the use of staff from government ministries has made it difficult for the FTC to demonstrate its independence.

The gas markets are undergoing constant restructure, but there is still a lack of competition. The gas industry in Japan is typical of an oligopoly with large disparities between operators in terms of scale. The gas assets are mainly owned by the three largest gas companies – Tokyo Gas, Osaka Gas and Toho Gas. Together these companies account for about 75% of the total LNG volumes in Japan.

The Japanese gas market is one of the more advanced within the region but the respective parts of the gas value chain require further deregulation to promote competition and improve economic efficiency. The government has been steadily committed to a policy focused on security of natural gas supply. The market has opened since deregulation started in 1995. A more competitive gas market will assist the private sector by securing supply and allowing trade across regions to improve efficiency, flexibility and security.

Possible solution – Promote competition

Japan could undertake a review of the gas business act to ensure that it adequately promotes competition and displays transparency in the administration of regulations.

Japan could also consider encouraging its main utilities to establish clear separation between its transmission, distribution and retail areas. This will ensure more transparency in the pricing of different services, and therefore encourage competition.

Infrastructure issues

In the gas sector, the country has grids centred near LNG import terminals. The trunk pipeline networks of these grids are not fully interconnected across the country. This is a key limitation. Integration would not only improve energy security but would allow for an integrated market.

In the case of Japan the lack of integration is partly due to economic feasibility and past regulatory impediments. The government is aiming to promote the development of gas pipeline networks and their interconnection.

Possible solution – Integration incentives

Japan should continue to consider new ways of ensuring that the market and regulatory framework create the right incentives for a cost-effective integration of the natural gas network. Integration will improve supply security and trade.

12.4.6 Republic of Korea

It appears that the Korean economy has scope for increasing productivity and attaining greater efficiencies through optimal gas resource utilisation.

To this end it also appears that the Korean government has not been consistent in its approach towards energy market reform, and that both the electricity and gas markets are currently in a state of uncertainty. This may in turn have a negative impact on the development of these markets as well as the ability of large companies (including both KOGAS and the large gas users) to plan forward with a degree of certainty.

There has been some progress in reducing market and regulator uncertainty in recent years, for example with imports for captive use and moving towards regulated third party access. Depending on the political will to support further reforms, the next step could be to establish an independent gas regulator and to invite greater industry participation.

Energy policy support for competitive fuels

Growth in the Korean gas markets over the previous ten years has occurred as a result of strong political support for the fuel, largely due the stated policy to diversify energy supplies and reduce reliance on oil. The political support for gas may no longer be so strong.

Gas demand in the residential sector is expected to continue growing, however some forecasts indicate a reduction in demand for gas in the electricity sector as renewable energy and nuclear energy are preferred to gas. Korea has committed substantial funds to the development of new renewable energy over the next 20 years in an effort to be more self reliant in energy, cut its reliance on fossil fuels and reduce emissions of carbon dioxide.

Potential solution

The issue of determining an appropriate fuel mix is not necessarily a matter of introducing market based pricing. The question for Korean authorities and energy companies is in principle similar to the key questions for countries that already have market based pricing:

1 What is the appropriate cost of carbon?

2 Which part (if any) should nuclear energy and renewable energy play in the fuel mix?

Clarification of these significant policy matters would preferably precede a move towards deregulation of the gas market.

Policy and regulatory approach

The Korean gas sector does not have an independent regulator, and there is not a clear policy on regulation in the event that the original gas market reforms are implemented.

Vertical integration and heavy government involvement in the gas industry call for a strong and independent regulator. Furthermore, uncertainty about regulation and market reform is also likely to be negative for potential gas market investors and hence negative for development of the gas market.

Potential solution

Consistent with recommendations put forward by the IEA, key reform initiatives in Korea could include the following:

- The establishment of a fully independent and powerful gas regulator.
- Effective unbundling of transmission and distribution of gas.
- Effective open access on the transmission pipelines and a non-discriminatory pipeline access code.
- Move towards creating market-based trading arrangements for wholesale gas.
- Progressive move towards full retail contestability, starting with big customers.

Infrastructure to manage seasonal demand

Korea seems to have adequate re-gasification capacity (nearly three times the level of current imports), and there are plans to further increase the storage facilities. However, storage of LNG is expensive.

Korea has very large swings in seasonal demand due to the use of gas for heating in the residential sector. This is not consistent with the economics of LNG production (which is to maintain output at a flat rate) and the preference of LNG producers to tie up production under long term bilateral contracts with Take-or-Pay commitments for the buyer.

Potential solution

In the absence of a liquid international spot market for LNG, Korea may consider alternative solutions to managing seasonal demand. This may include seasonal tariffs, initiatives to encourage the use of gas in areas with less seasonal variability (such as electricity) or alternative import arrangements (including piped gas).

It may also be worthwhile investigating opportunities to upgrade one or two import facilities in the region to re-export LNG, which in turn could see movement of smaller LNG cargoes between locations in Japan, Korea and northern China.

Competition and pricing

To have one large company (KOGAS) import most of the country’s LNG requirements may provide good outcomes if this approach is combined with appropriate pricing and monitoring of performance by an independent party. However, it may also provide opportunities to pass through high or avoidable costs. Consumers may benefit from market based pricing or regulated pricing in key parts of the gas supply chain, including third party access to infrastructure and greater ability for large customers to negotiate supply terms for gas.

In addition, wholesale electricity pricing based on plant economics (rather than availability) may give better signals for when and how to run the gas fired plants.

Potential solution

Even in the absence of full deregulation, Korea may benefit from further relaxing some of KOGAS’ monopolistic privileges and introduce competition in selected areas of the gas supply chain.

12.4.7 United States of America

As the US is the word's top energy consumer, it is not surprising that energy security is a key consideration for its policy makers. Overseas dependency is seen as a key risk to energy security, therefore the recent increase in domestic production of unconventional resources such as coal-bed methane and shale gas are a welcome and promising development.

In terms of energy security, increased penetration of gas in the energy mix would be desirable as at the moment, there is heavy reliance on oil and coal. This reliance also causes concerns in regards to CO2 emissions.

Overall the outlook for the US gas industry is very positive with strong demand for the commodity. This demand is expected to increase due to population growth, increased gas-fired power generation and environmental concerns.

The main challenge for the US gas industry is to determine how to satisfy this growing demand (either by increasing domestic production or via LNG imports) whilst maintaining gas prices at levels that are competitive with other fuels, such as coal.

The fact that the US has the most developed gas market in the world is a clear indication that impediments for growth have largely been removed but there are still some challenges that can be addressed.

Coal price competitiveness

Due to resource availability and price competitiveness, it is likely that coal will continue to be a major economic driver of the western states and the main source of electricity for some time. Development of carbon-capture and storage facilities will further support its use in the future.

The large use of coal (and oil) has placed the US as the top CO2 emitter in the world and concerns about the environment are inevitable. These days, the value to be placed on CO2 emissions is a key consideration for energy policy makers and is still being debated. Some states have already started their own emissions trading schemes but there is not a firm commitment at the federal level.

Potential solution – Value of CO2 emissions

The lack of agreement as to the pricing of CO2 emissions generates uncertainty and is preventing investments in gas, especially in the electricity generation sector. The federal government will make a decision regarding CO2 emissions but the timing and the value are uncertain.

A federal framework on emissions trading would harmonise the different approaches undertaken in the different states, and also send a strong signal to the rest of the world.

Regulatory issues

Many factors, including geographic location, environmental risk, regulatory issues and the financial environment, act as barriers to supply. In addition, some areas come under federal access restrictions. In 1999 the National Petroleum Council estimated that 213 Tcf of natural gas exists in such areas. The restrictions are the result of presidential and congressional leasing moratoriums, and affect the amount of natural gas resources that may be extracted and supplied.

Disputes between the states and the federal government over ownership and access to federal land and coastal waters, as well as continuing debate between the federal government and congress, has created uncertainty for companies willing to invest in the development of these resources. Lack of cooperation between the federal government and the states affects investment in new infrastructure in all stages of the supply chain. An additional obstacle is lengthy regulatory processes. It takes an average of four years to obtain approvals to construct a new natural gas pipeline.

Potential solution – Access to the commodity: Supply barriers

Improved coordination between the federal and state governments will facilitate the smooth working of approval processes and reduce regulatory issues.

Efforts may include additional focus on managing regulatory processes on a timely basis, considering the value of time in an industry that is capital-intensive.

A consistent regulatory and legal framework would alleviate environmental concerns about exploration and production and facilitate the processes for granting permission and royalties.

Developing a permitting process which allows diversification in the location of LNG terminals is advisable. Regulatory processes in this area are currently very time-consuming.

Demand management

In addressing concerns on energy security, the US government recognised the need to also address demand management as a way of reducing energy security concerns.

The per capita energy consumption in the US is one of the highest in the world, driven by high living standards, low energy prices and a lack of incentives and will to use energy efficiently.

Potential solution – Public education

The Japanese experience is a good example of what demand management can achieve. The US could follow this example and start to implement its plans to control energy demand.

The public could be further educated on energy savings and energy efficiency, which would also include highlighting the benefits of using gas instead of electricity. Greater awareness of the benefits of gas might also reduce community opposition to bringing LNG from overseas.

12.5 Impediments to gas market growth in the APP

For each country, the identification of gas market growth barriers and potential solutions for addressing the issues, draw on our analysis of each country's specific circumstances. In addition, findings from the analysis of gas market market efficiency and modelling of the energy markets are also taken into consideration.

Figure 12.5 summarises out the most significant barriers that have a direct impact on gas market growth in the seven APP economies. These barriers are in addition to the supply side issues which are considered to have an indirect impact on gas markets in the importing countries.

The impediments to gas market growth have been classified as global, regional and country specific. Global issues relate to all the APP Partners and are considered to be of high importance. Regional and country specific issues will have different priorities across the various domestic markets.

Figure 12.5 Summary of the key barriers and impediments to growth

Impediment to gas market growth	Description	Category
Energy policy • Value of CO_2	APP Partners should clarify policies on global warming and initiatives to reduce carbon emissions.	Global
Energy policy • Preferred energy mix • Support for other fuels	APP Partners should clarify their policies on how to achieve a target energy mix, including any preferences or privileges for certain fuels. Support for other fuels is likely to have a direct negative impact on gas use.	Global
Policy and regulatory approach • Independent regulator • Transparency	Market participants will benefit from having an independent regulator to oversee markets and implement reform.	Country specific
Competition and pricing • Market power • Third party access	The Asia-Pacific markets display varying degrees of market power, some of which can be addressed by introducing more competition in selected areas.	Asia-Pacific
Competition and pricing • Pricing distortions - wholesale • Pipeline tariffs	Subsidies and sub-optimal pricing will discourage investments in exploration and infrastructure, and lead to inefficient utilisation of resources.	Country specific
Infrastructure • Capacity to bring gas to market • Infrastructure planning • Seasonal demand	Impediments related to existing and required infrastructure are most profound in the developing countries with low gas penetration at present. Infrastructure planning will assist investors and provide assurance of the future commitment to gas.	Country specific in Asia-Pacific
Regulatory process	There is a need to co-ordinate and improve process approvals, but this issue is less important than some of the issues above.	North America

Energy policy

Energy policy issues related to the value of CO_2, the preferred energy mix for each country and specific support or privileges for a particular type of fuel are all linked. The common denominator is that the policies are developed individually, not collectively, by the respective governments.

Climate change and initiatives to reduce emissions of carbon dioxide are among the most topical issues at present. The purpose of this report is not to discuss climate change, but to highlight how initiatives, or lack of initiatives, to address global warming impacts on the ability to grow gas penetration in the APP gas markets.

Some countries are moving towards a solution with emission reduction schemes and other countries may consider a more direct approach. In principle, the questions for a market based economy and a centrally planned economy are the same: What is the appropriate cost of carbon, how will it affect the fuel mix, and which part (if any) should nuclear energy play in the fuel mix?

Potential implications of the carbon cost in an emission reduction scheme were also discussed in the section for modelling of the APP energy markets (refer Section 12.3 above).

Regulatory approach

Government policies and regulation work together and represent the two major categories that set basic market rules and provide certainty for investments and commercial activities.

Consistent with our findings in the benchmarking analysis and the review of regulatory best practice, some APP economies would benefit from establishing an independent regulator, transparency in regulatory processes, and implementation of market reform. These are country specific issues that have a high priority in less developed gas markets.

Competition and pricing

Barriers and impediments to growth relating to competition and pricing fall into two categories:

- Market power and varying degrees of competition between market participants.
- Wholesale gas prices and pipeline tariffs at below market rates or economic rates.

Market power may reflect the dominance of an incumbent, the size of the market or other limitations (ie geography or long distances) which inhibits multiple entities to be involved with the infrastructure development.

Fundamental competition and pricing issues may also be the result of government policies and the regulatory approach within specific countries. For example, gas wholesale prices below market in some countries are obviously in place for a good reason, and lower prices will make gas affordable and stimulate demand relative to other fuels. However, policies to subsidise gas prices may have unintended or unwanted effects on resource allocation and investors. For example, uncertainty about government policies on pricing may deter exploration for significant unconventional gas resources, such as coal seam gas, in these economies.

Infrastructure

Availability of infrastructure to bring gas to the end user is a key issue for gas market development in some countries. These issues are country specific in the Asia-Pacific region, as potential investors are likely to be discouraged by low pipeline tariffs for delivered gas and the absence of long term infrastructure planning.

We have not attempted to quantify the amount of investments in domestic pipelines that will be required to grow gas utilisation, but the challenge is likely to be substantial. Our study reveals that the requirement for infrastructure investment in LNG import terminals is very small compared to the planned capital expenditure on new electricity generation

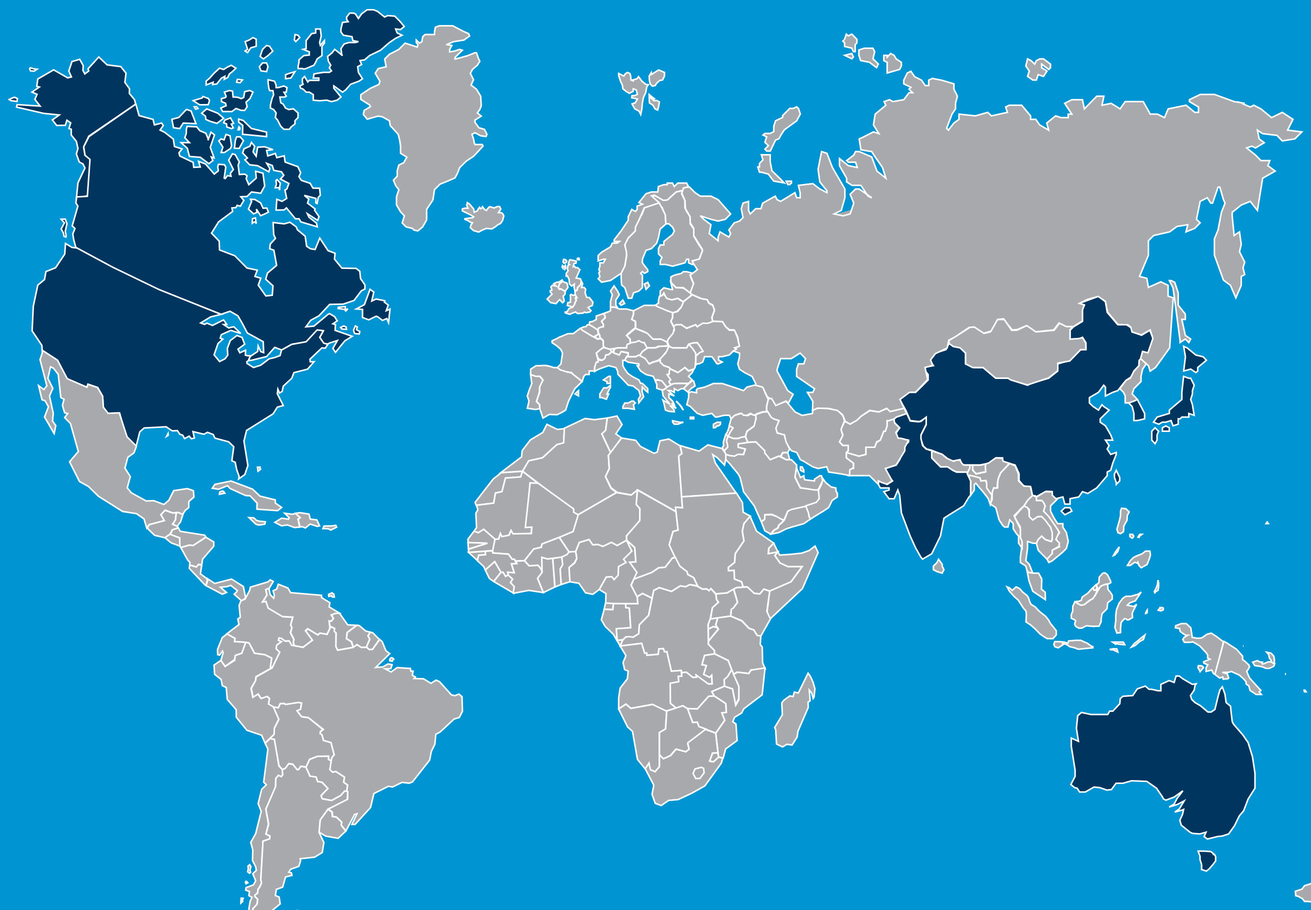
12.6 Summary of conclusions

The key messages coming from the analysis and interpretation of modelling results are:

- Producers and end users will continue to rely on each other to develop the market for natural gas and LNG. Importing countries will rely on the supply side to manage large-scale projects and provide security of supply. Producers will rely on governments in the importing countries to reduce risk by improving domestic gas markets to a point where stable and predictable government policies, regulation and end user demand provide sufficient certainty for the projects to move forward.
- There are significant differences between the efficiency of gas markets in the Atlantic Basin and the Asia-Pacific. The analysis and findings in many Asia-Pacific countries provide clear evidence that the basic foundations of efficient markets are either limited or not in place.
- There are substantial opportunities to grow gas market utilisation in the APP economies.
  - Opportunities to grow gas penetration are the greatest in the electricity generation sector, particularly in countries that already have low gas penetration.
  - Growth of gas in the energy mix will have a positive impact on energy security, greenhouse gas emissions and air pollution. The long term economic impact is also positive.
- Gas market growth must be underpinned by government policies and regulation that support market development and provide certainty for potential investors. Key focus areas for the energy policy include clarity around issues related to the cost of carbon emissions and the preferred energy mix for the respective countries.
- Government policies that endorse the use of coal will continue to provide a limitation to the growth of gas in terms of the energy mix.

Appendices

Australia • Canada • China • India • Japan • Korea • US



Appendix A Regulatory best practice principles

Asia Pacific Economic Cooperation (APEC) has 21 member countries including six of the seven APP economies. At their sixth meeting in Manila on 10 June 2004, APEC Energy Ministers encouraged member countries to move towards best practice as identified in ‘Facilitating the Development of LNG Trade in the APEC Region’ as outlined below.

These principles, developed by APEC’s Energy Working Group, may be regarded as a model for regulatory best practice principles for developing gas and LNG markets, and have been used when assessing regulatory practices in each of the seven APP economies (refer Part B –Analysis of gas markets by country).

Note: For the purposes of this report (and unless the context requires otherwise), the term *LNG* has been interpreted as reading *natural gas and LNG* and the wording has been updated accordingly.

Facilitating the development of trade

Trade – General

1 Economies should promote, or not impose measures that impede, the development of a proper and transparent LNG trading system that allows free and open markets to set the price across the natural gas and LNG value chain.

2 Economies should promote, or not impose measures that impede, the development of a flexible natural gas and LNG trading system that may include short term/spot trade, the capacity to develop a futures/options market for natural gas and LNG, and the removal of unnecessarily restrictive contractual practices.

3 Economies should establish predictable and stable legal and fiscal frameworks that protect the sanctity of contracts and do not distort the market through subsidies, inequitable cost allocation, uneconomic tariffs, or retroactive legislation. Legal frameworks should be clear and transparent to promote natural gas and LNG investment and the fiscal regime should support non-discriminatory policies for natural gas and LNG trade and investment.

4 Economies should remove legislative and regulatory impediments to the economic transportation of natural gas and LNG without compromising safety and security.

5 Economies should promote, or not impose measures that impede, the development of flexible access arrangements that encourage competition, anti-monopolistic behaviour and investment.

Financing/investment

6 When establishing and reforming energy market structures, economies should not impose measures that impede the development of economically viable natural gas and LNG projects.

7 Economies should develop energy market structures that promote investments with the capacity to support longer-term natural gas and LNG contracts to get green-field projects up and running and encourage increased natural gas and LNG trade.

8 Multilateral financial institutions should be encouraged to support the development and expansion of natural gas and LNG projects.

Emergency scenarios

9 Economies should develop and coordinate their security frameworks to enable natural gas and LNG to continue to be transported in a secure and safe manner, including sharing information on counter-terrorism measures.

10 Economies should promote, or not impose measures that impede, the development of a capacity to ameliorate 'sudden shocks' to the natural gas and LNG system (i.e. increase storage capacity, secure multiple sources of supply and excess capacity, establish time trade arrangements, encourage more trading flexibility among stakeholders).

Technology transfer and knowledge sharing

11 Economies should facilitate technology and skills transfer to help build the capacity of related sectors within member economies and reduce costs through the natural gas and LNG value chain.

12 Economies should facilitate natural gas and LNG trade through the collection and dissemination of natural gas data and the exchange of non-confidential commercial information among member economies (eg exports, imports, prices, supply, and demand). This sharing of information should be balanced with commercial and security concerns.

Permitting processes and regulatory issues

13 Economies should develop clear, transparent, non-discriminatory, coordinated and timely project approval processes for permitting natural gas and LNG facilities, including providing justifications for decisions.

14 Where appropriate, economies should consider the potential for making available government-owned land for the siting of natural gas and LNG infrastructure (eg receiving terminals).

15 Economies should share information on natural gas and LNG-related regulations, standards and quality specifications and, to increase the flexibility of trade, consider ways to further their harmonisation.

Public education

16 Economies should promote public education campaigns to build positive perceptions about natural gas and LNG by highlighting its demonstrated safety and reliability and emphasising its economic, environmental and energy security benefits.

17 Economies should clearly articulate their energy security policies as they relate to natural gas and LNG.

Appendix B Description of the models

The MARKAL energy model

Intelligent energy systems (IES)

Energy market modelling for this project has been performed with MARKAL models operated by IES. IES is a long-established consulting and software company that provides advisory services and software solutions to organisations dealing in energy markets. Whilst IES specialises in reforming and reformed electricity markets, it also does work in gas markets and macro/national energy systems. Central to the IES business model is research and development, which feeds into its advisory work and software products.

Mathematics of MARKAL

MARKAL is a linear programming model that represents the energy system by a large set of equations that governs system operation according to the technologies and data input. The objective of MARKAL is to optimise a chosen objective function subject to meeting all system constraints that are defined. A variety of such objectives are available within MARKAL but the one normally used is the minimum of total system discounted cost. The MARKAL solution is obtained by using a linear programming optimiser that finds the minimum objective function value while simultaneously satisfying all constraints that have been defined.

Formally, MARKAL is a partial equilibrium model that provides a market clearing solution for the energy sub-sector but does not have an explicit connection to other economic sectors. The output from the MARKAL solution is twofold. The most obvious is the ‘primary’ solution that details the technologies used each year, the extraction, importing and exporting of energy, the investments required, the fuel flows, system costs etc. However, of equal importance is the so-called ‘dual’ solution that provides shadow prices for all fuels that are consistent with the primary solution, that is, if fuels were valued at the shadow prices then there would be no excess demand for any fuel (supply ‘equals’ demand).

The shadow prices indicate the true worth (opportunity cost) of each fuel to the system. Fuels in unlimited supply will have a shadow price equal to the input cost but if supply is limited and there is an excess demand for the fuel, then the model may impute a higher ‘scarcity’ value to the fuel. This scarcity premium may also arise from supply limitations imposed by pipelines or other means.

Because there is explicit recognition of technologies in MARKAL, the model not only indicates fuel use in the various sectors but also is able to indicate which technologies are of major interest. This is particularly useful if technologies prove to be a robust selection under different scenario assumptions. The shadow prices in turn can provide guidance on policy settings to encourage the uptake of desirable technologies in the real world market environment.

MARKAL is very strong on analysing environment impacts and policies. Different types of emissions can be defined and associated with each technology at the point of release. Hence an assessment can readily be made of the amount of emissions and where they are occurring. Limitations can also be placed on the level of emissions on either an annual or cumulative basis. This allows the model to indicate the least cost way of meeting the emission standard, the cost of so doing, and the environmental ‘tax’ that would need to be applied to reach the standard via consumer choice.

The regional MARKAL and MARKAL-macro model extensions

MARKAL is a partial equilibrium model of the energy sector in a country or region. The key assumption here is that prices and policy settings in the non-energy sectors as well as neighbouring energy sectors that might be involved in energy trade can be assumed to remain fixed under the different energy sector cases that might be modelled. There are two extensions to MARKAL that extend its application.

The first is a regional version of MARKAL, which is now part of the standard MARKAL modelling system. With this facility, neighbouring regional or national MARKAL models can be imported into a combined MARKAL database, trade options defined between them, and the model run as a single system optimisation.

The second extension, called MARKAL-macro, is a facility that allows a MARKAL to interface directly with an input-output representation of the rest of the economy. This allows the effect of changes in the energy sector to be traced through the rest of the economy. Experience has shown that this can be relevant when a major part of the energy sector undergoes a significant shock.

The GTAP model

GTAP is a multi-region CGE model designed for comparative-static analysis of trade policy issues. The version of the model taken as a starting point for this study is as documented in Hertel (1996). The model used for this project distinguishes the 8 regions (the seven APP countries plus the rest of the world) and the 57 single-product sectors. In addition, there are three other agents in each region: a capital creator, a household and the government.

GTAP determines regional supplies and demands of goods and services through optimising behaviour of agents in competitive markets. Optimising behaviour also determines sector demands for primary factors, ie labour, capital, land and natural resources. In each region there are two types of labour (skilled and unskilled) and a single, homogenous capital good. In standard long-run comparative static applications of the model, total supplies of labour, land and natural resources are fixed for each region, while capital can cross regional borders to equalise percentage changes in rates of return.

The modelling of each regional economy in GTAP is based on ORANI, a single region model of Australia.[64] However, unlike ORANI, GTAP models inter-regional linkages arising from the flows of tradable goods and services and of capital. In doing so it ensures that each region's total exports equal total imports of these goods by other regions.

The basic theoretical assumptions made in GTAP are as follows:

64 Dixon, P., Parmenter, B., Sutton, J. and Vincent, D. 2002, ORANI: A Multisectoral Model of the Australian Economy, Contributions to Economic Analysis 142, North-Holland, Amsterdam.

Markets

Demand equals supply in all markets. Each market is assumed to be competitive, implying equality between the price received by the producer and the producer's marginal cost. Regional governments intervene in their own markets by imposing taxes and subsidies on commodities and primary factors, thus driving wedges between prices paid by purchasers and prices received by producers.

In markets for traded commodities, buyers differentiate between domestically produced products and imported products with the same name.[65] Product differentiation is also allowed between imports by region of origin. This allows for two-way trade across regions in each tradable product.

Input demands for production of commodities

Two broad categories of inputs to production are recognised: intermediate inputs and primary factors. In every region, each sector is assumed to choose the mix of inputs to minimise total cost for a given level of output. Sectors are constrained in their choice of inputs by a three-level nested production technology. At the first level, intermediate-input bundles and primary-factor bundles are used in fixed proportions. At the second level, intermediate input bundles are formed as combinations of imported bundles and domestic goods with the same name, and primary-factor bundles are formed as combinations of labour, capital and land. In both cases the aggregator function has a constant elasticity of substitution (CES) form. At the third level, imported bundles are formed as CES combinations of imported goods with the same name from each region.

Household demands

Each region has a single representative household. Aggregate household expenditure is determined as a constant share of total regional income (household consumption plus government expenditure plus national savings). The household buys bundles of commodities to maximise utility subject to its expenditure constraint.[66] The bundles are CES combinations of domestic goods and import bundles, with the import bundles being CES aggregations of imports from each region.

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65 Allowing for the possibility that imported products may not be perfectly substitutable for the corresponding domestic product is an idea first put forward in Armington (1969). Armington, P.S. (1969), A theory of demand for products distinguished by place of production. IMF Staff Papers (16), pp. 159-178.

66 GTAP represents consumer demands using the Constant Difference Elasticity implicit expenditure function.

Demands for inputs to capital creation and the determination of investment

The cost-minimising capital creator in each region combines inputs to assemble units of capital, subject to a nested production technology similar to that facing each sector for current production. The only difference is that the capital creator does not use primary factors. The use of primary factors in capital creation is recognised indirectly through inputs of commodities to capital construction.

Investment in each region is financed from a global pool of savings. Each region contributes a fixed proportion of its income to the savings pool. In standard GTAP, there are two alternative ways that this pool is allocated to investment in each region. The first makes investment in each region a fixed proportion of the overall size of the pool. Thus if the pool increases by 10%, investment in each region increases by 10%. The second relates investment allocation to relative rates of return. Regions that experience increases in their rate of return relative to the global average will receive increased shares of the investment budget, whereas regions experiencing reductions in their rate of return relative to the global average will receive reduced shares.

Government demands for commodities

The share of aggregate government expenditure in each region's income is held fixed. Government expenditure is allocated across commodities by a Cobb-Douglas distribution. The allocation of total expenditure on each good to domestically produced and imported versions is based on the same nesting scheme used to allocate total household expenditure on each good.

Database

The GTAP data base comprises: input/output data for each region; bilateral trade data derived from United Nations trade statistics; and support and protection data derived from a number of sources. The simulations reported in this study are based on version 6 of the database, as described in McDougall and Dimaranan (2005).[67] The database contains estimates of production costs, final demand values, bilateral trade values and various tax levels for 2001.

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[67] Dimaranan, Betina V. and Robert A. McDougall, Editors (2005) Global Trade, Assistance, and Production: The GTAP 6 Data Base, Center for Global Trade Analysis, Purdue University.

Appendix C Summary of modelling assumptions

Sources of data for the base case

For the purpose of energy market modelling of the base case, information has predominantly been sourced from the following publications:

Australia	Australia Energy, National and State projections to 2029/30 by ABARE December 2007. Additional assumptions as outlined below +
Canada	Canada's Energy Outlook The Reference Case 2006 by Natural Resources Canada
China	World Energy Outlook 2007 - China's Energy Prospects
India	World Energy Outlook 2007 - India's Energy Prospects
Japan	Japan Long Term Energy Outlook: A projection up to 2030 under environmental constraints and energy market changes by The Institute of Energy Economics 2006.
Korea	The 3rd Basic Plan for Long Term Electricity Supply and Demand 2006 – 20020, and APEC Energy Demand & Supply Outlook 2006 - Korea
US	Annual Energy Outlook 2008 by the Energy information administration (EIA), June 2008.

+Australia – Additional assumptions

- The mandatory renewable energy target will increase to 20% of renewable energy or 45,000 GWh by 2020.
- The gas supply curve reflects a gradual move towards higher domestic prices.
- Queensland has targets for gas generation as share of total electricity generation.
- A carbon cost of \$20 per tonne of CO_2 will apply from January 2011.

Economic and commodity price assumptions

Economic growth

Economic growth assumptions for GDP are consistent with information found in the main reference documents for each country.

	2007	2010	2012	2015	2020+
Australia	3.0%	3.0%	2.5%	2.5%	2.5%
Canada	2.7%	2.3%	2.3%	2.3%	2.3%
China	7.7%	7.7%	7.7%	4.9%	4.9%
India	7.2%	7.2%	7.2%	5.8%	5.8%
Japan	2.0%	1.5%	1.5%	1.5%	1.1%
Korea	5.0%	3.6%	3.6%	3.6%	2.5%
US	2.5%	2.7%	2.7%	2.4%	2.4%

Currency and interest rates for MARKAL modelling

All modelling is in current dollars and the discount rate is 8%. All countries are represented in US dollars. The AUD / USD exchange rate is assumed at parity.

Commodity prices for MARKAL modelling

Price assumptions (mainly relevant to the scenarios) are broadly in line with international market prices when the gas market modelling was performed:

Commodity	Value expressed in current dollars
Crude oil	\$100 / bbl or \$17.00 / GJ
Petroleum products	12.5% premium over crude oil
Natural gas and LNG	\$8.50 / GJ
Coal	\$85 / tonne or \$2.98 / GJ
Cost of carbon (for emissions of CO2)	Developed countries: \$35 / tonne from 2013 Developing countries: \$0

Primary energy

Renewable energy generation is converted to primary energy on 1:1 basis (eg 1PJ output = 1 PJ of primary energy supply).

Nuclear electricity generation is converted to primary energy using an efficiency of 33% (consistent with IEA assumptions). Nuclear is treated as a domestic fuel in all countries.

The gas market scenario

The gas market scenario reflects modelling of the following changes compared to the base case:

Australia	It is known today that a carbon cost of $35 / tonne will be introduced from January 2013. Results are modelled for the electricity sector. New investments in brown coal generation are not permitted, but black coal generation is treated in accordance with economics. There are no investments in nuclear generation capacity. Investments in renewable energy are limited by a constraint on wind energy to be no more than 20% of system capacity.
Canada and Japan	It is known today that a carbon cost of $35 / tonne will be introduced from January 2013. Results are modelled for electricity generation. Nuclear and renewable energy generation capacity is consistent with the base case.
China, India and Korea	Assume a gradual increase in gas penetration of 0.625% per annum (consistent with growth rates seen in other countries). The increased gas usage is shared evenly between industry and the electricity generation sector.
USA	It is known today that a carbon cost of $35 / tonne will be introduced from January 2013. Results are modelled for electricity generation. Nuclear energy is consistent with the base case. A gradual increase is permitted for renewable energy other than hydro, subject to economics and within the following restrictions: (a) Renewable energy generation (other than hydro) to represent maximum 20% of system capacity by 2025. (b) The increase in wind energy is restricted to 15% per year. Modelling shows that the economics for new coal fired generation and new gas fired generation is very similar, and investment decisions will therefore be based on a range of factors such as location, fuel availability and alternative use. Hence, the additional assumption is that 50% of new capacity will be coal and 50% of new capacity will be gas.

Appendix D Emission factors

Emission factors vary across the seven APP countries for a variety of reasons, including quality of energy input, the actual use of energy and the application of pollution controls.

Definitions of the various types of pollutants may differ (for example the granularity of particulates). In addition, comparison of data is further complicated by the fact that many publications do not disclose the underlying assumptions.

Calculations in this study are based on one set of definitions and assumptions sourced from the EIA as set out in the table below. Output from the modelling is presented in relative terms compared to 2008 emissions in order to compare trends rather than actual emissions of CO2 and pollution.

Emission factors per unit of energy input

Emission factors	Pounds / Billion BTU		
	Gas	Oil	Coal
Carbon dioxide	117k	164k	208k
Nitrogen oxides	92	448	457
Sulphur dioxide	0.6	1,122	2,591
Particulates	7	84	2,744

Notes to the table of emission factors:

No post combustion removal of pollutants. Bituminous coal burned in a spreader stoker is compared with No. 6 fuel oil burned in an oil-fired utility boiler and natural gas burned in uncontrolled residential gas burners. Conversion factors are: bituminous coal at 12,027 Btu per pound and 1.64 percent sulphur content; and No. 6 fuel oil at 6.287 million Btu per barrel and 1.03 percent sulphur content - derived from Energy Information Administration (EIA), Cost and Quality of Fuels for Electric Utility Plants (1996).

Source: Energy Information Administration (IEA), Office of Oil and Gas. Carbon Monoxide: derived from EIA, Emissions of Greenhouse Gases in the United States 1997, Table B1, p. 106. Other Pollutants: derived from Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Vol. 1 (1998).

Appendix E Energy security measures

Energy security measures in this study broadly reflect those published by the Asia-Pacific Energy Research Centre in 2007.

Diversification of Primary Energy Demand (DoPED)

DoPED is a modified version of the Shannon Diversity Index, a diversity index used to measure biodiversity. This measure considers both the significance of diversification in terms of abundance and equitability of sources. The indicator, adapted from this index is shown below:

D = −Σ Pi ln Pi and DoPED = D / D Max = D ln T

Where:
D = Shannon's Diversity Index
Pi = share of primary energy supply i in total primary energy supply
i = 1…T: primary energy source index (T sources are utilised)

The final value acquired from this indicator is normalised on a 0-100 scale.

A value close to zero implies that the economy is dependent on one energy source (and therefore reflects a higher risk of energy supply security). A result close to 100 implies that the economy's energy sources are evenly distributed among the main energy sources.

Non carbon fuel portfolio (NCFP)

The NCFP of each economy takes into account the share of demand that hydro, nuclear, and NRE contribute to total primary energy demand. The indicator is shown below:

NCFP = (Hydro + Nuclear + New and renewable energy) / Total primary energy demand

Net energy import dependency (NEID)

The Shannon Diversity Index for this indicator was altered to reflect the impact of both diversification and imports on energy supply security. The NEID of each economy is weighted by the consumption intensity of each primary energy source (PES). The indicator, adapted from this index is shown below:

D = −Σ Ci Pi ln Pi subject to Ci = 1 Mi

DoPED (import reflective) = D / D Max = D ln T

NEID = 1 - DoPED (import reflective) / DoPED

Where:
Ci = correction factor for Pi
Mi = share of import in PES of source i

The final value acquired from this indicator is calculated as a percentage. A value closer to zero implies that the economy relies on domestic sources to meet its primary energy demand (PED). A result close to 100% implies that the economy is highly dependent on imports and may possess a limited supply of domestic sources to meet its PED. Thus, a higher value reflects a higher risk of energy supply security.

Appendix F Abbreviations

Abbreviation	Meaning
AER	Australian Energy Regulator
APP	Asia-Pacific Partnership on clean development and climate
APP partners or APP7	The APP's seven member countries of Australia, Canada, China, India, Republic of Korea, Japan and the United States
APEC	Asia-Pacific economic cooperation with 21 member economies of Australia, Brunei Darussalam, Canada, Chile, China, Hong, Kong, Indonesia, Japan, Republic of Korea, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, Philippines, Russia, Singapore, Chinese Taipei, Thailand, United States and Viet Nam
APPEA	Australian Petroleum Production & Exploration Association
Bcf	Billion cubic feet
Bcm	Billion cubic metres
Btu	British thermal unit
CBM	Coal bed methane
CO2	Carbon dioxide
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CSG	Coal seam gas, more frequently referred to as CBM outside Australia
DoPED	Diversification of primary energy demand
EIA	Energy Information Administration (USA)
ETS	Emissions Trading Scheme
FERC	Federal Energy Regulatory Commission (USA)
GAIL	Gas Authority of India Ltd
GDP	Gross domestic product
GL	Gigalitre
GWh	1 gigawatt hour = 1,000 megawatt hours = 1 million kilowatt hours
IEA	International Energy Agency
JOGMEC	Japan Oil, Gas and Metals National Corporation
KOGAS	Korea Gas Company
Korea	Republic of Korea
Kt	Thousand tonnes
LDC	Local distribution company

Abbreviation	Meaning
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
METI	Ministry of Economy, Trade and Industry (Japan)
MOCIE	Ministry of Commerce , Industry and Energy (Korea)
Mt	Million tonnes
NCFP	Non carbon fuel portfolio
NDRC	National Development and Reform Commission (China)
NEB	National Energy Board (Canada)
NEID	Net energy import dependency
NYMEX	New York Mercantile Exchange
ONGC	Oil and Natural Gas Corporation (India)
PJ	1 petajoule = 1,000 terajoules = 1 million gigajoules
PNGRB	Petroleum and National Gas Regulatory Board (India)
Tcf	Trillion cubic feet
TPES	Total primary energy supply
TW	1 terawatt = 1 thousand gigawatts = 1 million megawatts
US	United States of America

Appendix G Figures table

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