8 GAS EXPLORATION, PRODUCTION, WHOLESALING AND TRADE

Moomba petroleum and natural gas plant, Cooper Basin. Brendan Esposito (Fairfax Images)

Natural gas producers search for, develop, extract and process gas to a standard suitable for industrial and residential purposes.

8 GAS EXPLORATION, PRODUCTION, WHOLESALING AND TRADE

This chapter considers:

> the role and significance of the gas exploration and production sector
> exploration and development in Australia
> gas production and consumption and the future outlook for growth
> gas prices
> the structure of the sector, including industry participants and ownership changes
> gas wholesale operations and trade
> market developments.

8.1 The role and significance of the gas exploration and production sector

Natural gas is predominately made up of methane, a colourless and odourless gas denoted by the chemical symbol CH_4. It usually occurs in combination with other hydrocarbons, in liquid or gaseous form. It is found in underground reservoirs trapped in rock, often in association with oil—conventional natural gas. Methane extracted from coal seams—coal seam gas (CSG) or coal seam methane (CSM)—is also found in Australia in sufficiently large quantities to be a viable alternative to conventional gas supplies. There are also alternative renewable gas sources including biogas (landfill and sewage gas) and biomass, which includes wood, wood waste and sugar cane residue (bagasse). The Australian Bureau of Agricultural Resource Economics (ABARE) projection data suggests that renewable energy comprises only about 5 per cent of the primary energy mix in Australia and is predominantly biomass (68 per cent). Biomass and biogas make up about 16 per cent of primary gas consumption in Australia.[1]

Exploration for conventional gas and CSM occurs in conjunction with the search for other hydrocarbon deposits beneath the earth's surface. Explorers use sophisticated survey techniques—such as aeromagnetic, airborne gravity and seismic—and drilling to detect and determine the extent of hydrocarbon deposits.

Conventional natural gas can occur in isolation or contain natural gas liquids (ethane, propane, butane or condensate) or be associated with oil. 'Associated gas' can be separate from oil (free gas) or dissolved in the crude oil (dissolved gas). In addition, raw natural gas may contain impurities such as water, hydrogen sulphide, carbon dioxide, helium, nitrogen and other compounds.

During gas **production** (extraction and processing) discovered gas and other oils and liquids are extracted and separated and impurities removed; and then the raw gas is processed to a standard suitable for sale. Gas production includes underground gas storage (which is the injection and recovery of gas usually in a depleted gas field), construction of pipelines for the transport of raw gas to a processing plant and the processing facilities.

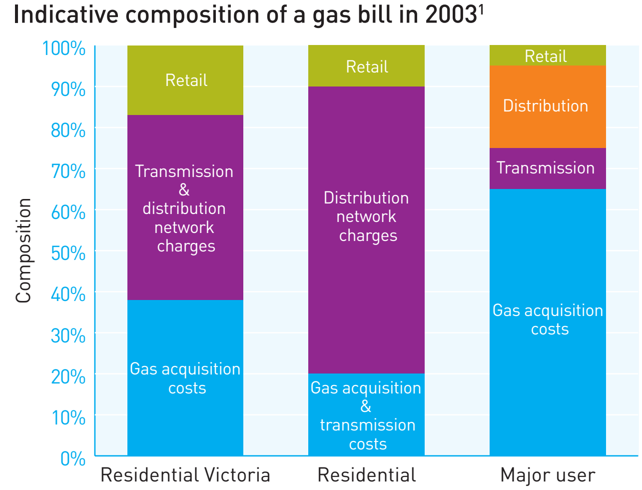
Permits are required to explore for and produce gas and other petroleum products in Australia.

Natural gas exploration and production is the first link in the natural gas supply chain and a significant contributor to the Australian economy. Production of natural gas for the domestic market was worth around $2500 million in 2004–05. Exports of liquefied natural gas (LNG) were valued at around $3700 million in the same year.[2]

The cost of gas typically accounts for the bulk of the cost of a gas supply service for major users, such as electricity generators and metals manufacturers. In contrast, the cost of gas usually accounts for a relatively small share of a residential gas bill, while transport charges typically make up the bulk of the cost of a gas supply service (figure 8.1). Location affects the cost of gas supply with consumers located close to the source of supply, such as Victorians, facing a lower transport cost component.

Figure 8.1

Indicative composition of a gas bill in 2003[1]

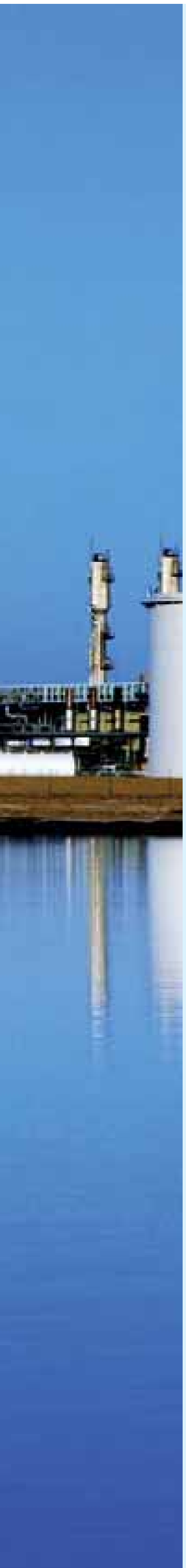


1. 'Residential' is based on Envestra data supplied to the Productivity Commission.

Source: KPMG, *The effectiveness of competition and retail energy price regulation*, 2003; Charles River and Associates, *Electricity and gas standing offers and deemed contracts 2004–2007*, December 2003; Australian Gas Association and Envestra, as published in Productivity Commission, *Review of the gas access regime*, Inquiry report no. 31, 2004, pp. 37 and 46.

1 Based on projections for 2005-06 from C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE Research Report 06.26, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006, table A2, p. 53.

2 ABS, *Mining operations, Australia*, companion data, cat. no. 8415.0, Canberra, October 2006.



Box 8.1 Reserves and resources definitions

Reserves: the quantities of gas anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves are categorised by the level of certainty associated with the estimates.

Proved (1P): The volumes of gas reserves that analysis of geological and engineering data suggests are recoverable to a high degree of certainty (90 per cent confidence). Reserves may be developed or undeveloped.

Probable: The volumes of gas reserves that analysis of geological and engineering data suggests are more likely than not to be recoverable under current economic and operating conditions. There is at least a 50 per cent probability that the quantities actually recovered will exceed the sum of estimated proved plus probable reserves (2P). In the Australian context booking of gas reserves as 2P usually requires gas contracts and development approval to be in place.

Possible: The volumes of gas reserves recoverable to a low degree of certainty. There is at least a 10 per cent probability that the quantities actually recovered will exceed the sum of estimated proved plus probable plus possible reserves (3P).

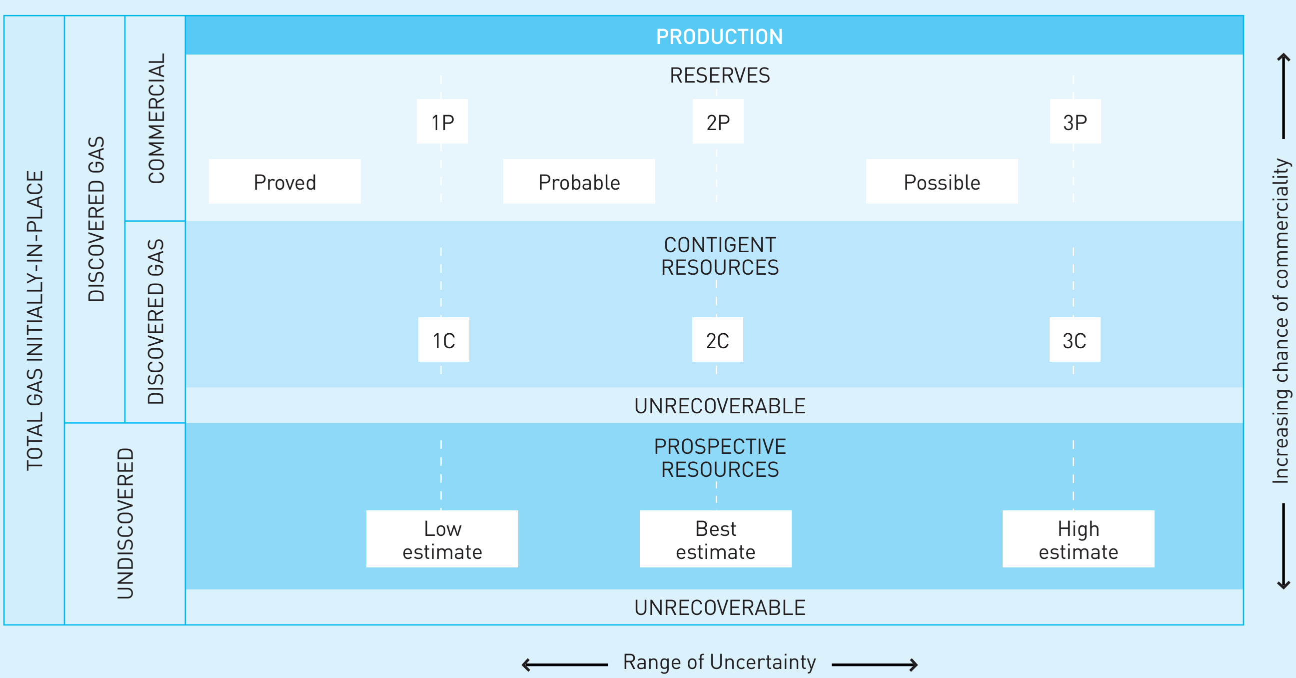
Resources: refers to the remaining quantities of gas estimated to be in-place.

Contingent resources: are estimated to be potentially recoverable from accumulations that are known but not currently considered to be technically mature or commercially viable. Probabilities can also be attached to these resources.

Prospective resources: The quantity of gas estimated at a given date to be potentially recoverable from undiscovered accumulations by application of future development projects.

Unrecoverable: is that portion of discovered or undiscovered gas potentially in-place that is estimated at a given date not to be recoverable.

Figure 8.2
Gas reserves and resources classification framework



Source: EnergyQuest, *Energy quarterly production report*, February and May 2007; Society of Petroleum Engineers 2007, Petroleum resources management system 2007, viewed 24 May 2007<http://www.spe.org>.

Table 8.1 Natural gas reserves and production in Australia

GAS BASIN	CONTINGENT RESOURCE[1]		PROVED & PROBABLE RESERVES (2P)[1]		PRODUCTION IN 2006[2]	
	PJ	%	PJ	%	PJ	%
Amadeus	0	–	218	0.5	20.6	2.3
Bonaparte	19 500	19.9	1 687	4.2	–	–
Browse	30 000	30.7	–	–	–	–
Carnarvon	44 030	45.0	24 313	60.0	305.2	33.6
Perth	0	–	37	0.1	10.6	1.2
Total West/North	93 530	95.6	26 255	64.8	336.4	37.0
Cooper–Eromanga	0	–	1 225	3.0	170.7	18.8
Gippsland	3 670	3.8	5 377	13.3	243.5	26.8
Otway	250	0.3	1 568	3.9	70.1	7.7
Bass	350	0.4	315	0.8	7.6	0.8
Bowen–Surat	na	na	312	0.8	22.4	2.5
Gunnedah	na	na	na	na	1.0	0.1
Total East/South	4 270	4.4	8 797	21.7	514.3	54.1
Conventional supplies	**97 800**	**100.0**	**35 052**	**86.6**	**828.1**	**91.2**
Bowen–Surat	4 500	na	5 337	13.2	70.3	7.7
Sydney	na	na	102	0.3	9.9	1.1
Coal seam methane	**na**	**na**	**5 439**	**13.4**	**80.2**	**8.8**
Domestic total	102 300		40 491	100.0	**908.3**	**100.0**
Exports (LNG)					657.8	
Total	102 300		40 491	100.0	1566.1	

na not available. 1. As at 31 December 2005. See box 8.1 for details on the classification of reserves. 2. Production in the 2006 calendar year.

Source: EnergyQuest, *Energy quarterly production report*, February and May 2007.

8.2 Australia's natural gas reserves

Australia has abundant natural gas reserves. Current estimates indicate that there are around 35 000 petajoules[3] of conventional supplies of proved and probable (2P) reserves (box 8.1), with contingent resources estimated to be around 97 800 (table 8.1). Total proved and probable natural gas reserves, those reserves with reasonable prospects for commercialisation, stand at around 40 500 petajoules (table 8.1). This includes around 5500 petajoules of CSM. Given the relatively early stage of development of the sector and the size of Australia's coal resources, CSM resources are potentially large, well above conventional resources in southern and eastern Australia—the area in which CSM is currently produced. For example, from December 2005 to December 2006 estimated proved and probable reserves of CSM have increased from around 3300 petajoules to 5500 petajoules —an increase of 62 per cent.[4]

At current rates of consumption and production Australia has sufficient proved and probable reserves to meet domestic and export demand for about 26 years.[5] Exploration for natural gas is a comparatively recent development, which largely began in the 1960s. The development of CSM is even more recent, occurring only within the past decade. It is likely that further exploration will lead to additional discoveries and verification of reserves.

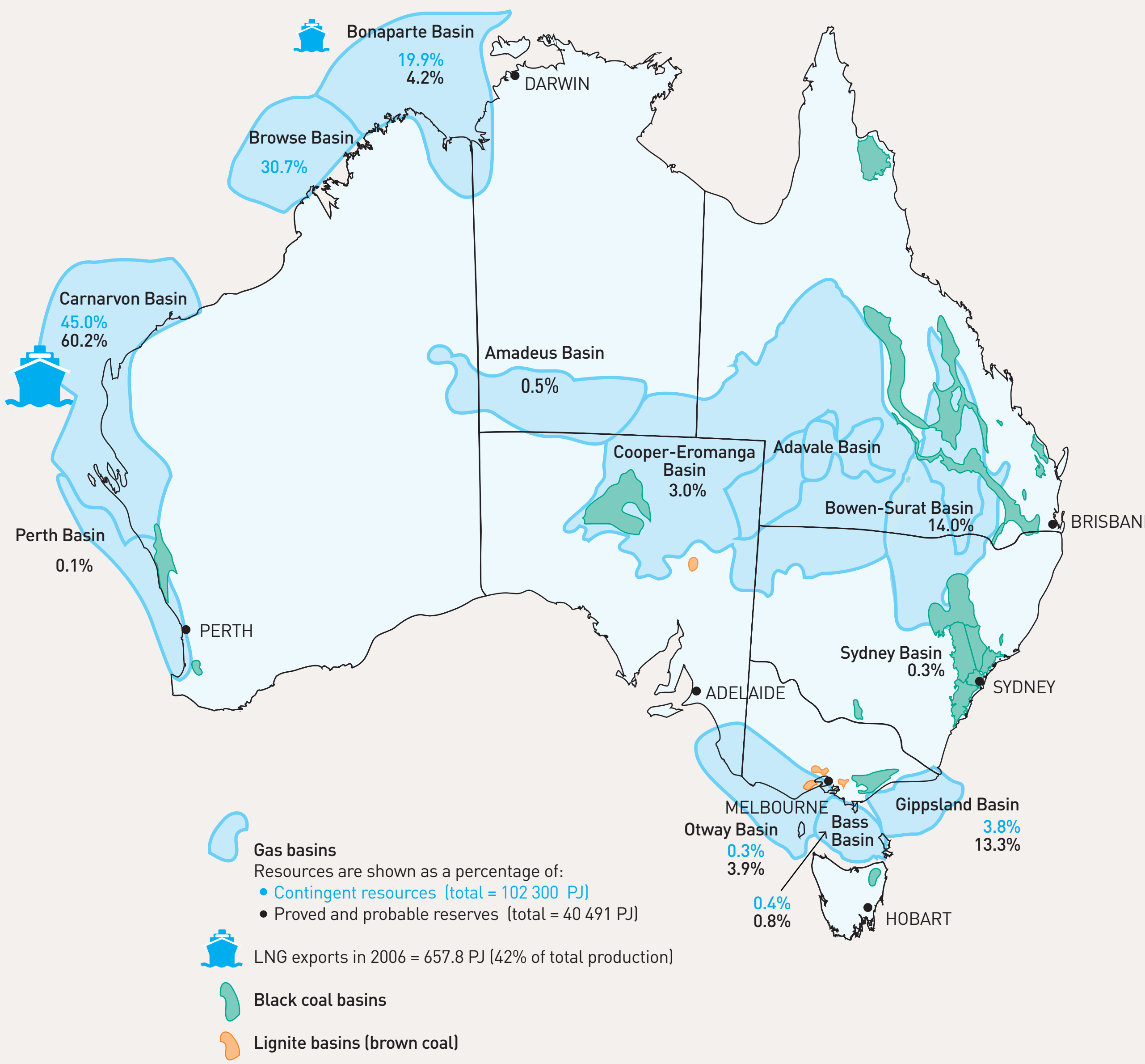
3 A petajoule is 10^{15} joules. A joule is a unit of energy, which is sufficient to produce one watt of power continuously for one second. One joule is approximately the energy required to heat one gram of dry, cool air by 1°C. To raise the temperature by 1°C of an average room (3m × 3m, 2.5m high) would take 23 700 joules.

4 EnergyQuest, *Energy quarterly production report*, February and May 2007.

5 The Ministerial Council on Energy and Ministerial Council on Mineral and Petroleum Resources have established a joint working group on natural gas supply. The group is to report in 2007 and, among other things, must consider domestic gas supply and demand, prices, long-term energy security and the need for a national gas plan.

Figure 8.3

Australia's natural gas reserves



1 Locations are indicative only.

Source: K Donaldson, *Energy in Australia 2006*, ABARE report, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2007; EnergyQuest, *Energy quarterly production report*, February and May 2007.

Figure 8.3 shows the location of Australia's major natural gas reserves. The most significant reserves of proved and probable gas supplies are in Western Australia. The Carnarvon Basin off the north-west of Australia holds about 60 per cent of Australia's known conventional natural gas reserves and currently accounts for about 34 per cent of gas produced for the domestic market (table 8.1). Gas produced from the basin meets over 95 per cent of Western Australia's gas demand. The state's remaining gas needs are supplied from the smaller and more mature gas-producing region of the Perth Basin, located to the south of the Carnarvon Basin. Gas from the Perth Basin is mainly transported on the Parmelia Pipeline.

The North West Shelf joint venture converts some gas produced from the Carnarvon Basin to LNG gas for export. In 2005–06 around 646 petajoules of gas produced from the basin were exported as LNG. Australia is the world's fifth largest LNG exporter, after Indonesia, Malaysia, Qatar and Algeria. According to EnergyQuest, Woodside expects LNG demand to double over the next ten years while forecast supply has been lowered.

The Bonaparte–Timor Sea Basin along the north-west coast of Australia is estimated to contain a contingent resource of about 19 500 petajoules. The basin is estimated to contain about 4 464 petajoules of 2P gas reserves. Australia's share of this reserve is 1 687 petajoules with the rest belonging to Timor Leste. Bayu-Undan (located in the Australia-Timor Leste Joint Development Area) is the only area in the basin producing gas at this time. Development of the basin centres on LNG production for export. The first shipment of LNG was in February 2006 and overall production for the year to December 2006 was around 123 petajoules (including Australia's share of about 12.3 petajoules, with the rest attributable to Timor Leste). The Blacktip field is being developed to supply domestic gas to the Northern Territory with the first gas expected to flow from January 2009.

To the south-west of the Bonaparte Basin lies the Browse Basin. It contains significant natural gas resources. These are currently subject to development studies for LNG.

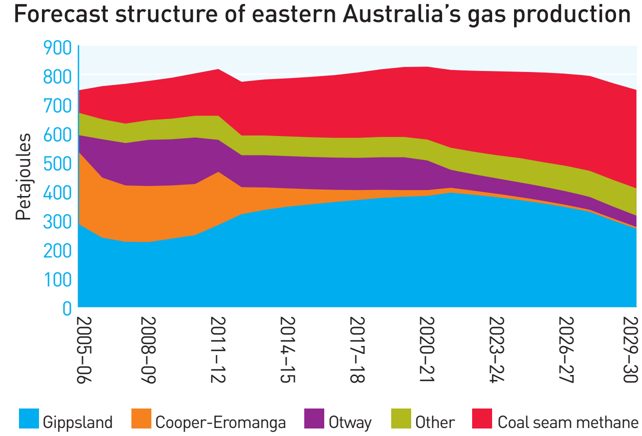
A small reserve of 218 petajoules of gas remains in the Amadeus Basin in central Australia. The basin is currently producing around 20 petajoules of gas a year, which is sufficient to meet all current demand for gas in the Northern Territory. The basin is in decline, however, so that gas for electricity production will soon be supplemented by supplies from the Blacktip field.

The most significant reserves of gas in the south-east of Australia are found in the Gippsland Basin off the Victorian south coast. The basin accounts for around 13.3 per cent of Australian reserves. In 2006 around 243 petajoules of gas (about 27 per cent of total domestic production) were produced from the Gippsland Basin. Some of this gas was exported to New South Wales. The remaining gas is enough to meet more than 90 per cent of Victoria's gas needs. There are also significant reserves of gas in the Bass and Otway basins to the east of the Gippsland Basin.

The Cooper–Eromanga Basin in the north-east of South Australia and south-west Queensland is a mature gas producing region. It has an estimated 1225 petajoules of commercial reserves remaining. At current rates of production of around 158 petajoules of gas a year this is enough to last about nine years. About 14.4 per cent less gas was produced in 2006 than in 2005, and production is expected to decline more rapidly after about 2011–12 (figure 8.4). However, the basin is still being actively explored so new discoveries of gas may extend the life of the basin.

Figure 8.4

Forecast structure of eastern Australia's gas production



Source: C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE research report 06.26, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006.

The Bowen–Surat Basin, which extends from northern New South Wales to northern Queensland, is also a relatively mature gas-producing area. It has conventional reserves of about 312 petajoules suitable for commercial production. This is enough for about 14 years at current rates of production. The basin also contains significant quantities of CSM. Reported figures suggest that there are about 152 000 petajoules of gas-in-place, although only about 5500 petajoules are booked as proved and probable (2P) reserves.[6] This provides enough gas to supply all of Queensland's gas requirements for at least 20 years. Current production of CSM from the basin is about 70 petajoules a year, more than three times the level of conventional gas supplies from the basin. CSM from the basin provides over 50 per cent of Queensland's current gas requirements. Wood Mackenzie predicts that in 2007, CSM production will increase by more than one-third to 98 petajoules or 79 per cent of final gas demand in Queensland.[7]

CSM is also found in the Sydney Basin. The gas-in-place in New South Wales is estimated at around 97 000 petajoules, although there is considerable uncertainty about how much of this can be developed.[8] Commercial production within the Sydney Basin began in 1996 at Appin and since 2001 there has been a small quantity of CSM produced close to the Sydney market. CSM currently supplies only around 8 per cent of gas demand in New South Wales. A number of companies are actively engaged in attempts to increase production.

Conventional gas and CSM are found in the Gunnedah Basin in northern New South Wales. Eastern Star is developing this area. The company also has conventional gas and CSM exploration rights in the Clarence Moreton Basin of New South Wales.

There is potential for further development of CSM in other regions where black coal is present, including Tasmania.

Currently CSM production occurs in Queensland and New South Wales only. Nevertheless, CSM is currently the fastest growing sector of gas production. Production has grown nearly three-fold since 2004, mainly as a result of increased production in the Bowen–Surat Basin in Queensland (figure 8.5). ABARE expects CSM production to continue to grow at a rapid rate. It forecasts that annual production will reach to over 300 petajoules by 2029–30 and become the main source of gas supply in eastern Australia (figure 8.4).

CSM provides a highly competitive alternative for conventional natural gas. It also provides opportunities for significant cost savings by delaying the need for investment in infrastructure to ship gas from more distant sources such as PNG or the Timor Sea.

Nevertheless, ABARE currently forecasts that strong demand, in part driven by greenhouse initiatives[9], and dwindling supplies from the Cooper–Eromanga Basin mean that from as early as about 2012–13 there may be an opportunity for supplies from outside the region to enter the eastern Australian market.[10]

ABARE forecasts are, however, likely to be conservative. While ABARE figures suggest that by 2020 CSM will account for about 40 per cent of eastern Australia's gas demand, Wood Mackenzie expects the fuel to account for about half of that demand.[11] There is likely to be substantial growth in gas production from offshore Victoria and stronger growth in CSM production than currently predicted could delay the need to import gas from outside the region.

6 Based on RM Davidson, LL Sloss, and LB Clarke, *Coalbed methane extraction*, IEA coal research, London, 1995, as reported in A Dickson and K Noble, 'Eastern Australia's gas supply and demand balance', *APPEA Journal* 2003, 143.

7 S Wisenthal, 'Coal seam to supply 80pc of Qld's gas', *The Australian Financial Review*, 5 March 2007, p. 16.

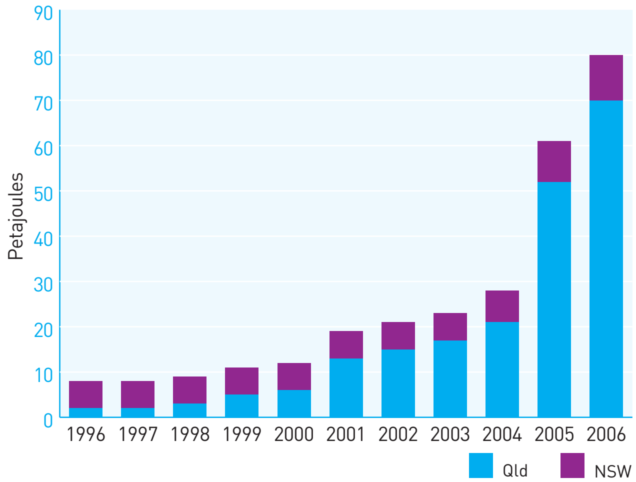
8 Based on K Brown, DA Casey, RA Enever, and K Wright, *New South Wales coal seam methane potential*, Geological survey of New South Wales coal and petroleum geology, New South Wales Department of Mineral Resources, Sydney, 1996, as reported in A Dickson, and K Noble, 'Eastern Australia's gas supply and demand balance', *APPEA Journal* 2003, 143.

9 See appendix B for detail on initiatives targeted at reducing greenhouse gas emissions.

10 C Cuevas-Cubria, and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE Research Report 06.26, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, December 2006.

11 see footnote 7.

Figure 8.5
Coal seam methane production 1996–2006



Source: Data supplied by EnergyQuest.

8.3 Exploration and development in Australia

In Australia, the Crown owns petroleum resources. The states and territories have the statutory rights to onshore resources and resources in coastal waters while the Australian Government controls the resources in offshore waters. The governments coordinate activities through the Ministerial Council on Mineral and Petroleum Resources.

Exploration rights

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.

The three most common licences are:

- an **exploration licence**, which provides a right to explore for petroleum and to carry on such operations and execute such works as are necessary for that purpose, in the permit area
- an assessment or **retention licence**, which provides a right to conduct geological, geophysical and geochemical programs and other operations and works, including appraisal drilling, as are reasonably necessary to evaluate the development potential of the petroleum believed to be present in the permit area
- a **production licence**, which provides a right to recover petroleum, to explore for petroleum and to carry on such operations and execute such works as are necessary for those purposes, in the permit area.

Petroleum tenements are usually allocated through a work program bidding process, which operates somewhat like a competitive tendering process. Under this approach anyone may apply for a right to explore, develop or produce in a tenement based on offers to perform specified work programs. The minister chooses the successful applicant by assessing the merits of the work program, the applicant's financial and technical ability to carry out the proposed work program and any other criteria relevant to a tender.

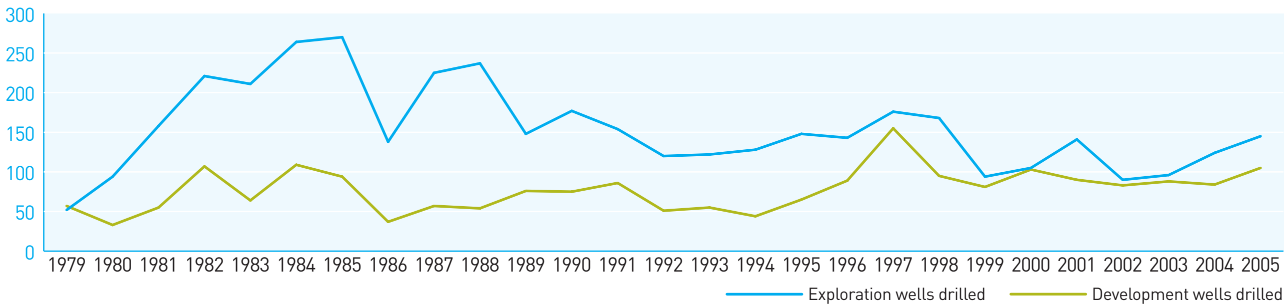
While the approach to issuing licences is relatively consistent across states and territories there are significant differences across jurisdictions in licence tenure and conditions.

Offshore projects are located outside the three nautical mile boundary and fall within the Australian Government's jurisdiction. The Australian Government applies the petroleum resource rent tax to petroleum projects in its jurisdiction.[12] Onshore projects fall within state and territory jurisdiction and are subject to the excise and royalty regime. Tasmania applies a royalty of 11–12.5 per cent of the value of the petroleum at the well-head. Western Australia applies a royalty of 5–12.5 per cent. The other states and the Northern Territory apply a royalty of 10 per cent.

12 The North West Shelf exploration permits WA-P-1 and WA-P-28 are excluded from the tax. These projects are subject to the excise and royalty regime. The Australian Government shares the royalty with Western Australia.

Figure 8.6

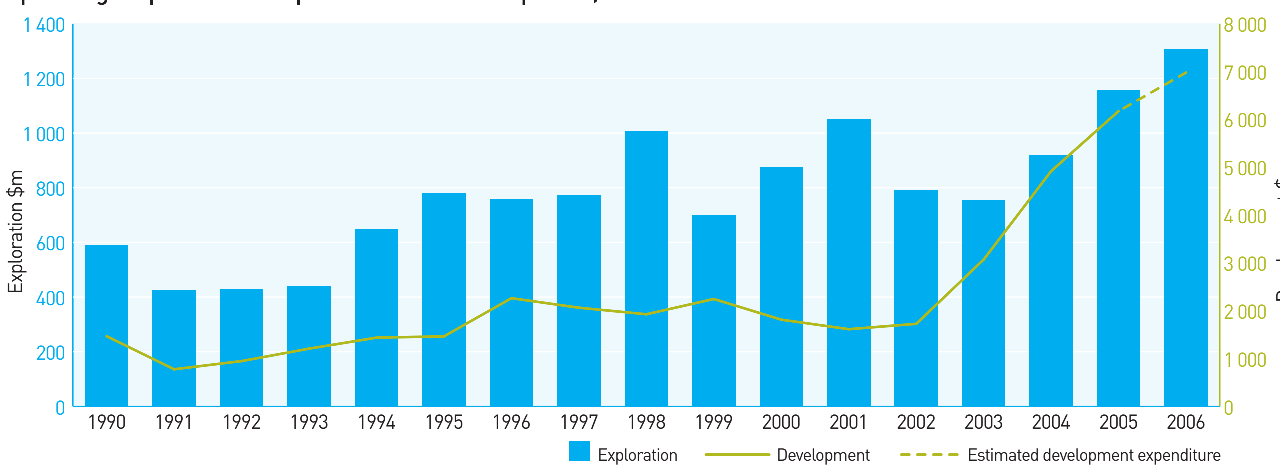
Petroleum exploration and development wells drilled, 1979–2005



Source: Geoscience Australia, *Oil and gas resources of Australia 2004*, Canberra, 2006.

Figure 8.7

Spending on petroleum exploration and development, 1990–2006[1,2]



1. Exploration, development and production expenditure (nominal prices) incurred in the Joint Petroleum Development Area is included in the above figures.
2. Development expenditure in 2005 and 2006 is assumed to increase at the same rate as exploration expenditure.

Sources: Geoscience Australia, *Oil and gas resources of Australia 2004*, Canberra, 2006; ABS, *Mineral and petroleum exploration, Australia*, September 2006, Cat. no. 8412.0; AER estimates.

In addition to royalties the Western Australian Government seeks to impose a domestic gas reservation requirement on export gas (LNG) projects. The domestic reserve is determined through negotiation between the Western Australian Government and LNG project proponents. The government's policy aim is to ensure that sufficient supplies of gas are available to underpin Western Australia's long term energy security and economic development. Based on gas reserves and forecast LNG production the government currently estimates that the equivalent of 15 per cent of LNG production is required to meet the state's future domestic gas needs.

Exploration and development activity

Petroleum exploration activity tends to vary considerably. Exploration activity is primarily driven by prices, but is also affected by a range of other factors, including access to acreage, equipment costs, perceptions of risks and rewards and availability of finance.

Figure 8.6 shows Australian petroleum drilling activity from 1979 to 2005. Exploration drilling activity grew rapidly from 1979 through to the mid-1980s with an average of almost 600 wells drilled a year. From the mid-1980s exploration activity started to decline. There has been some recovery from the early 1990s,

Table 8.2 Development of Australian gas basins

GAS BASIN	GAS EXPLORATION BEGAN	GAS FIRST DISCOVERED	GAS PRODUCTION BEGAN
Amadeus	1964	1964	1983
Bonaparte Gulf	1969	1999	Scheduled from 2009
Timor Sea	1969	1981–82	2006
Carnarvon	1953	1971	1984
Perth	1964	1966	1971
Cooper–Eromanga	1959	1963	1969
Gippsland	1964	1965	1970
Bass	1965	1966–73	2006
Otway	1892	1980	1987
Bowen–Surat	1900	1900	1961
Sydney, Gunnedah, Clarence–Moreton	1910	1980s	1996

Source: Department of Primary Industries (Vic), *History of petroleum exploration in Victoria*, <http://www.dpi.vic.gov.au>; viewed: 19 October 2006; GPInfo, *Petroleum permits of Australasia*, Encom Petroleum Information Pty, Ltd, North Sydney 2006; Industry Commission, *Study into the Australian gas industry*, Report, Canberra, 1995.

in part in response to reduced regulation and reform in the east coast gas market, and again more recently in response to higher world oil and gas prices. The overall decline in the number of exploration wells drilled in part reflects technological improvements, such as 3D seismic technology, which reduces the need for drilling. The number of development wells drilled has shown a slight upward trend over the same period.

There is currently high demand for petroleum acreage and significant exploration and activity throughout Australia due to the high world price of oil, continuing demand for gas and higher LNG prices.

Figure 8.7 shows spending on petroleum exploration and development activity from 1990 to 2006. Spending on exploration activities more than doubled from $589 million in 1990 to $1307 million in 2006. Over the same time development expenditure grew from $1467 million to an estimated $6979 million with much of the growth occurring after 2002. Over the period 1990 to 2001 development expenditure grew by an average of about 1 per cent a year. Between 2002 and 2006 expenditure increased four-fold growing at an average annual rate of about 42 per cent a year. The recent increase in spending reflects the start of several major projects and the rapid growth in the cost of offshore development projects. High demand for equipment has significantly increased the cost of offshore exploration and development. For example, in the past couple of years drilling rig costs have doubled (from about $200 000 to $400 000 a day) as activity has increased in response to the surge in world oil prices.[13]

The increase in costs appears to be having an impact on Western Australia with gas producers no longer offering long term contracts because of uncertainty about future gas field development costs, future prices and the impact of the government's domestic gas reserve policy.[14]

Table 8.2 sets out the chronology of the development of gas basins in Australia. Demand for gas, prices, and infrastructure costs can affect the rate at which a gas basin or field is developed. Offshore the Northern Territory and in the Carnarvon Basin in Western Australia there has been a considerable lag between gas discovery and production. Establishment of a domestic market for the Carnarvon gas has required substantial investment in pipeline infrastructure. The two major pipelines in Western Australia—the Dampier to Bunbury and Goldfields Gas pipelines represent investment of around $3.5 billion in historic terms.

13 Geoscience Australia, *Oil and gas resources of Australia 2004*, Canberra, 2006.
14 ERA, *Gas issues in Western Australia,* Discussion paper, Perth, 2007.

Coal seam methane

In production, CSM is a close substitute for conventional natural gas. Exploration, development and production of CSM is occurring in New South Wales and Queensland black coal deposits and may become prospective in other black coal regions in Australia. The recent commercial development of CSM stems from Queensland Government energy and greenhouse policies but also reflects improved extraction technology and increased demand for gas with associated higher gas prices.

The profitability of a CSM project is affected by several factors including well flow rates and spacing, drilling and development costs, water disposal costs and access to land and markets. In particular, wells need to be able to produce gas at a rate that is able to supply gas contracts. This means that the coal seams need to have either high gas content with reasonable permeability or low gas content with high permeability. Many wells are usually required for a CSM project, which adds to drilling costs. Water produced during extraction of CSM is often very saline so that the disposal of water is becoming a significant issue. Another disadvantage of CSM is that production rates cannot be varied.

Queensland and New South Wales CSM projects have some commercial advantages over conventional natural gas. The gas is found closer to the surface and under lower pressure than conventional natural gas. It usually has a relatively high concentration of methane, lower levels of impurities and is closer to markets than conventional natural gas. These features reduce exploration and production costs and other risks. It also allows for a more incremental investment in production and transport than bringing a major new conventional natural gas development on stream.

In New South Wales most of the current exploration and production activity relates to CSM. In Queensland around 70 per cent of the production permits issued since 2004 relate to CSM. In addition, in 2005–06, a total of 216 wells were drilled in Queensland to explore for, develop and appraise CSM. By comparison 33 wells were drilled in search of conventional natural gas.

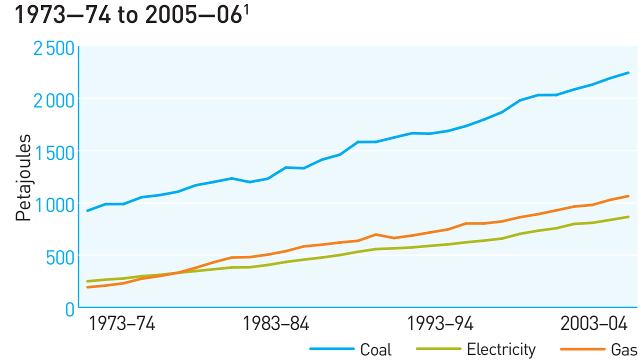
8.4 Gas production and consumption

Natural gas is a versatile source of energy, which has a range of industrial, commercial and domestic applications, including electricity generation (mainly for fuelling intermediate and peaking generators) and as an input for manufacturing pulp and paper, metals, chemicals, stone, clay, glass, and certain processed foods. In particular, natural gas is a major feedstock in ammonia production. It is also used to treat waste materials, for incineration, drying, dehumidification, heating and cooling, and cogeneration. In the transport sector, natural gas in a compressed or liquefied form is used to power vehicles. In a commercial and residential setting natural gas is used for space conditioning and refrigeration, heating and cooking.

Natural gas also has the advantage that it burns cleaner than other fossil fuels, such as oil and coal, and produces fewer greenhouse gas emissions per unit of energy released. For an equivalent amount of heat, burning natural gas produces about 45 per cent less carbon dioxide than burning black coal.

Figure 8.8

Australian gas, coal and electricity consumption, 1973—74 to 2005—06[1]

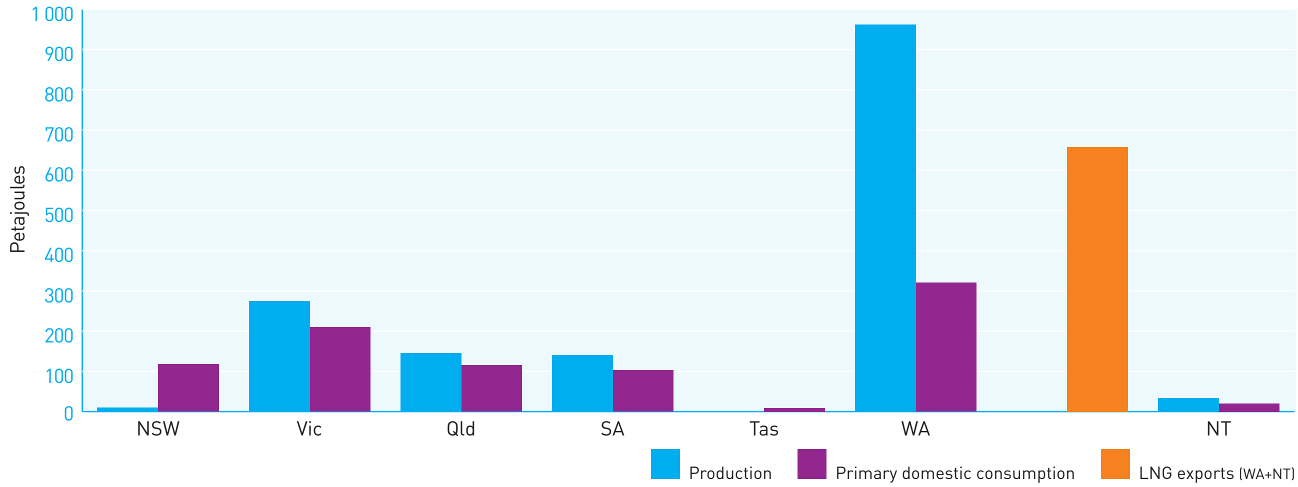


1. Data for 2005–06 based on ABARE projections.

Sources: ABARE, 'Energy Statistics – Australia', Table F, <www.abareconomics.com>; C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE Research Report 06.26, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, December 2006.

Figure 8.9

Gas production and consumption by state and territory, 2006[1, 2]



1. Production data allocated to the states and territories on the basis of EnergyQuest production data by basin. It is assumed that the production in the Otway Basin is divided equally between South Australia and Victoria. 2. Domestic consumption data is based on ABARE forecasts scaled to match production.

Source: C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE Research Report 06.26, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006; EnergyQuest, Energy quarterly production report, August 2006.

The advantages of gas are reflected in relatively strong growth in domestic gas consumption compared with other energy sources, such as coal and electricity (figure 8.8). While starting from a low base, since 1973–74 gas consumption has risen from around 200 petajoules to 1200 petajoules in 2005–06, a six-fold increase. By comparison over the same period use of black and brown coal has grown from 900 petajoules to 2300 petajoules and electricity from 250 petajoules to 900 petajoules, which on average is about a three-fold increase.

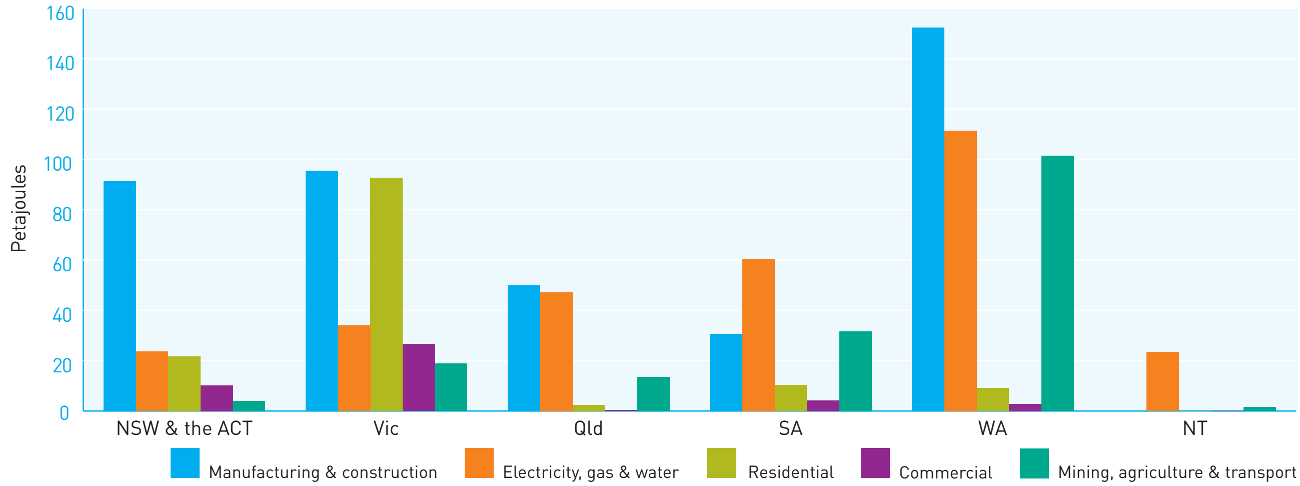
Historical restrictions on interstate trade have limited trade in gas. The 1994 agreement among Australian governments to introduce free and fair trade in gas between and within the states and territories, the introduction of regulated third party access rights to natural gas pipelines and other National Competition Policy and related reforms have created trading opportunities and incentives for expansion of the gas transmission network. Construction of the Eastern Gas Pipeline and the SEA Gas Pipeline has contributed to the opening of the Patricia-Baleen field in the Gippsland Basin and the Minerva and Casino fields in the Otway Basin. Producers from these fields compete with the Cooper–Eromanga Basin producers to supply gas to New South Wales and South Australia, for example. Trade in gas now occurs across south and eastern Australia, with Tasmania and New South Wales mainly relying on gas imported from other states. However, relatively high transport costs limit opportunities to trade in gas such that gas collected from each basin is principally sold into the nearest market. Gas from the Bowen–Surat Basin, for example, is principally marketed into Queensland. Figure 8.9 indicates current production and consumption patterns.

CSM development in Queensland and New South Wales is significantly increasing competition in the sector and is the main driver behind planned infrastructure development over the next 5–10 years (section 8.5). This is likely to see the rapid expansion of the Queensland pipeline system in the next few years and its interconnection with the rest of south-east Australia to allow for the export of Queensland gas to New South Wales, South Australia and Victoria.

Offshore gas rig

Figure 8.10

Sectoral primary natural gas consumption by state and territory, 2004–05[1]



1. Mining accounts for at least 69 per cent of the mining, agriculture & transport sector in each state and territory.

Source: ABARE, *'Energy statistics – Australia'*, Table F, http://www.abareconomics.com/interactive/energy/excel/table_f.xls, viewed: 24 November 2006.

Western Australia and the Northern Territory are geographically isolated from the major eastern and southern markets and gas is not traded across state borders. However, LNG exports are growing rapidly and now account for much of Western Australia's production. Similarly, all current production from the Bonaparte Basin is for export. Increased international trade in gas has meant greater integration of Western Australia's domestic market and the global gas market, with subsequent increases in domestic gas prices (section 8.5).

In Australia natural gas is predominantly used for industrial manufacturing purposes and for electricity generation. The mining sector is also a major user of gas in Western Australia (figure 8.10). The residential sector accounts for only a small share of consumption in all states and territories, except in Victoria where the sector accounts for around a third of total consumption.

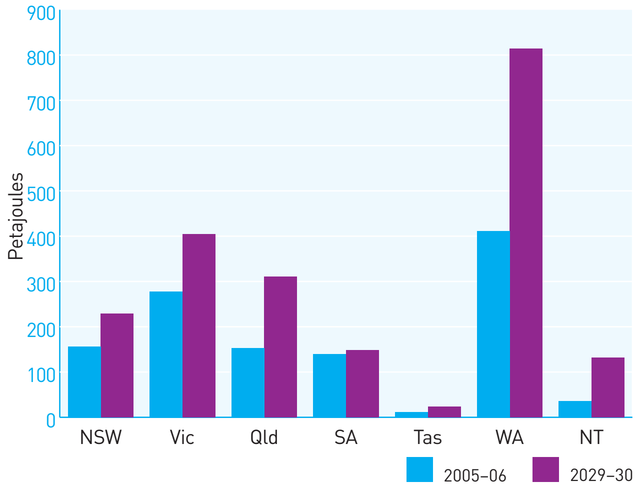
Future outlook

ABARE has projected that over the period 2005–06 to 2029–30 primary energy consumption in Australia will increase by about 43 per cent from 5715 to 8162 petajoules, growing at an average annual rate of 1.4 per cent. It expects consumption of natural gas to be an important contributor to this growth, projecting gas consumption (including in the LNG export sector) to increase by 2.2 per cent a year, accounting for 37 per cent of the total increase in primary energy consumption. It expects much of this growth to occur in the Northern Territory, Western Australia and Queensland (figure 8.11).

ABARE expects primary natural gas consumption for the Northern Territory to increase about four-fold from about 36 petajoules in 2005–06 to 132 petajoules in 2029–30. Key contributors to this growth are energy intensive refining and the LNG export sector. ABARE also expects that a significant increase in Australia's alumina refining capacity and the new Burrup Peninsula ammonia fertiliser plant will contribute to projected strong growth in natural gas consumption in Western Australia. ABARE forecasts that overall natural gas consumption in Western Australia will almost double from 423 petajoules in 2005–06 to 797 petajoules in 2029–30.

Figure 8.11

Primary gas consumption by state and territory[1]



1. Based on ABARE forecast data. Actual production data for the 2006 calendar year is provided in table 8.1.

Source: C Cuevas-Cubria and D Riwoe, *Australian Energy: National and state projections to 2029-30*, ABARE Research Report 06.26, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006.

In Queensland, mining and minerals processing industries and increased use of gas for electricity generation are expected to contribute to strong growth in natural gas consumption in that state. ABARE projects that gas consumption will rise from about 153 petajoules in 2005–06 to 311 petajoules by 2029–30. In particular the effect of the Queensland Government's greenhouse and energy policies is expected to lead to an increase in demand for gas-fired electricity generation in preference to other fuels such as coal.

ABARE expects gas use in Tasmania to double, growing from a low base of about 11 petajoules in 2005–06 to 23 petajoules by 2029–30. ABARE forecasts relatively modest growth in natural gas consumption in New South Wales, Victoria and South Australia. In South Australia, for example, natural gas consumption is projected to grow by only 0.2 per cent between 2005–06 and 2029–30. The decline in manufacturing in South Australia and Victoria has been reducing demand, although this is offset to some degree by greater use of gas for electricity generation.

8.5 Gas prices

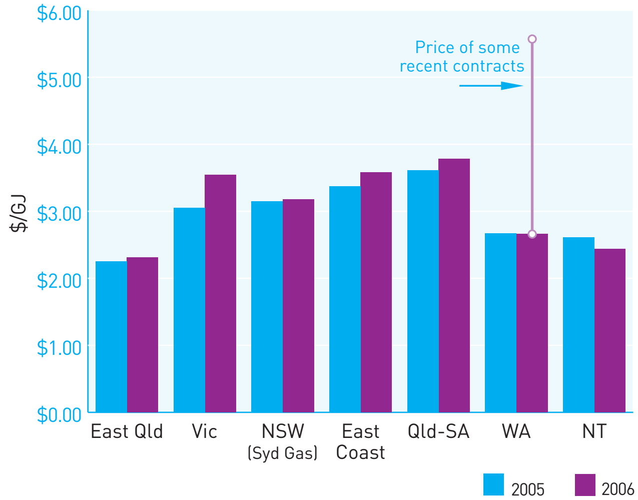
Gas is sold mostly under confidential long-term take or pay contracts. Historically contracts have lasted for up to 30 years, but more recently contracts have typically been shortened to 10–15 years. The contracted price of gas is usually increased each year by 80–90 per cent of the consumer price index. Unlike LNG, prices under domestic gas contracts are generally not related to oil prices.

Because gas contracts are confidential, comprehensive price information is not readily available. However, initiatives to improve price transparency are in train (section 8.8). Available information suggests that gas prices tend to vary within and across states. Figure 8.12 provides illustrative gas prices for different regions in Australia in 2005 and 2006. Available data suggest that current prices are within a band of about $2.25–$3.80 a gigajoule with the lowest prices occurring for CSM in eastern Queensland and New South Wales and for conventional supplies under existing long-term contracts in the Northern Territory and Western Australia.[15] Prices for conventional natural gas are relatively similar across most of the east coast of Australia, ranging from around $3.50–$3.80 a gigajoule in 2006. Prices on the spot market in Victoria have typically been around $3 a gigajoule. This is below long-term contracted prices for conventional gas. CSM contract prices have typically been lower, around $2.00–$2.50 a gigajoule, but more recently prices have increased to $2.50–$3.00 a gigajoule.

15 Price estimates reflect field gate prices, except for Queensland, which reflects the price for delivered gas.

Figure 8.12

Selected natural gas prices by region[1]



1. Data for the second quarter of 2005 and 2006. Field gate prices, except for Queensland where the price includes delivery costs. Prices for the Vic and WA are based on data provided by the Department of Industry and Resources (WA). Prices for East Qld reflect prices received by CH4. Prices for the East Coast are based on weighted average prices received by Santos and Origin Energy and mainly reflect prices for Cooper Basin gas, but also includes other east coast conventional gas and CSM, Western Australian (conventional and LNG), US and Indonesian gas.

Source: EnergyQuest, *Energy quarterly production report*, August 2006, p. 52; Data supplied by the Department of Industry and Resources (WA).

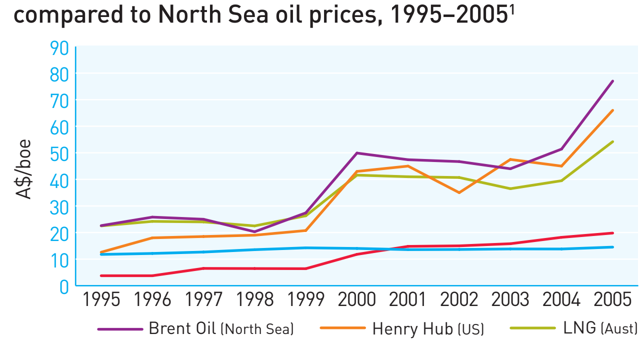
Contract prices for gas in Western Australia vary but are generally considered to be within the range of $2.00 to $2.90 a gigajoule with an average of about $2.45 a gigajoule ($14.25 a boe (barrel of oil equivalent)). However, according to EnergyQuest, in late 2006, some Western Australian domestic gas prices rose to over $5 a gigajoule in response to higher LNG prices. EnergyQuest provided an example of one new contract in which the gas price was $5.48 a gigajoule.[16] The Economic Regulation Authority of Western Australia also reports that wholesale gas prices in the Western Australia market range between $5.50 to $6.00. This represents a doubling of gas contract prices compared with early 2006.[17] During 2006 there was a considerable tightening in the supply of gas in Western Australia. The Economic Regulation Authority of Western Australia reports that gas producers are only offering contracts with a maximum term of five years with volumes restricted to about ten terajoules a day.[18]

The main cause appears to be uncertainty about future gas field development costs in light of the significant cost increases. Other contributing factors may include uncertainty about future gas prices and the government's domestic gas reservation policy.

Australia has had relatively low gas prices by international standards. Figure 8.13 compares gas prices in Australia and the United States with the price of Brent crude oil (sourced from the North Sea). Despite some significant increases in some Australian gas prices over the past decade, the ex-plant price of gas in Victoria and Western Australia has averaged around a third of the price in the United States (which was equivalent to an average of about $9.72 a gigajoule in 2005). Australian prices are also well below those achieved in the United Kingdom and Europe. In 2006, for example, the average wellhead price of gas in the United Kingdom was about $16.44 a gigajoule, while in Europe it was around $10 a gigajoule. This compares with prices generally less than $4 (less than $20 a boe) throughout much of Australia, although under some recent contracts Australian LNG prices have approached parity with oil prices.

Figure 8.13

Australian and United States average gas prices compared to North Sea oil prices, 1995–2005[1]



1. Brent oil is the average Brent oil price. Victoria Bass Strait gas is a Wood Mackenzie estimate of average Victorian gas prices ex-plant. Henry Hub gas is an annual average of the US Henry Hub spot price. LNG is measured free on board (net) based on an estimate of the average ex-plant LNG price from the North West Shelf adjusted to take account of gas used in liquefaction. All prices are measured in Australian dollars in terms of barrel of oil equivalents (boe).

Source: Department of Industry and Resources (WA), *Western Australian mineral and petroleum statistics digest 2005–06*, 2006, Perth.

16 EnergyQuest, *Energy quarterly production report*, February 2007.

17 Economic Regulation Authority, *Gas issues in Western Australia*, Discussion paper, Perth, 2007.

18 Economic Regulation Authority, See footnote 17.

In the United States and Europe gas prices follow oil prices closely. This has generally not been the case in Australia, primarily because of Australia's geographic isolation and high transport costs. The domestic price of gas reflects local supply and demand, which is characterised by relatively low consumption and high reserves. Increased demand for LNG is, however, leading to increases in the domestic price of gas, particularly in Western Australia.

8.6 Industry structure

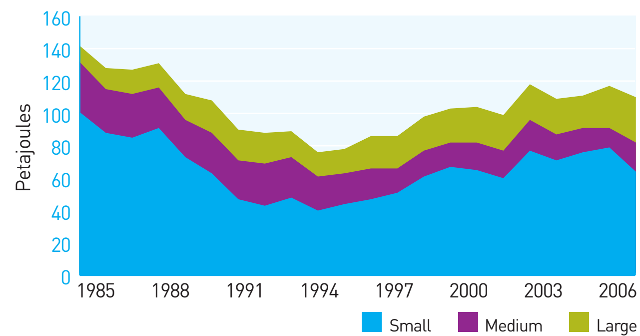
Long-term declining profitability of the global petroleum industry resulted in significant rationalisation of the industry during the second half of the 1980s and early 1990s. There was also considerable merger activity among companies of all sizes. In particular, major oil companies merged to create even larger companies, such as ChevronTexaco and ExxonMobil. These mergers allow control of very large petroleum fields that can be profitable even at relatively low crude oil prices.

Reflecting higher oil prices and continuing gas demand in Australia, the number of companies involved in gas and oil exploration, particularly junior explorers, has expanded since the mid-1990s. Companies floated in the last 10 years and their market capitalisation include AWE ($1219 million), Tap ($235 million), Arc ($306 million), Roc ($886 million), Queensland Gas Company ($1116 million), Arrow Energy ($825 million) and Sydney Gas ($130 million). Over the same period Beach Petroleum has grown to a market capitalisation of $919 million, Australian energy major AGL ($5.7 billion) has entered the gas production sector and both Apache and Mitsui have become important domestic gas producers.

The changing structure of the industry is illustrated by figure 8.14, which shows the change in industry structure from 1985 to 2006 for exploration in offshore waters that are under Australian Government jurisdiction.

Figure 8.14

Companies holding equity in gas and oil exploration permits in offshore waters, classified by size, 1985 to 2006[1]



1. Data reflects companies with permits issued by the Australian Government for offshore waters only (excludes onshore permits and permits in the JPDA and waters under state and territory jurisdiction). 2. Large refers to multinational and super-major companies and subsidiaries. 3. Medium refers to non-multinational companies with a significant market capitalisation. 4. Small companies have a moderate market capitalisation and are not major producers.

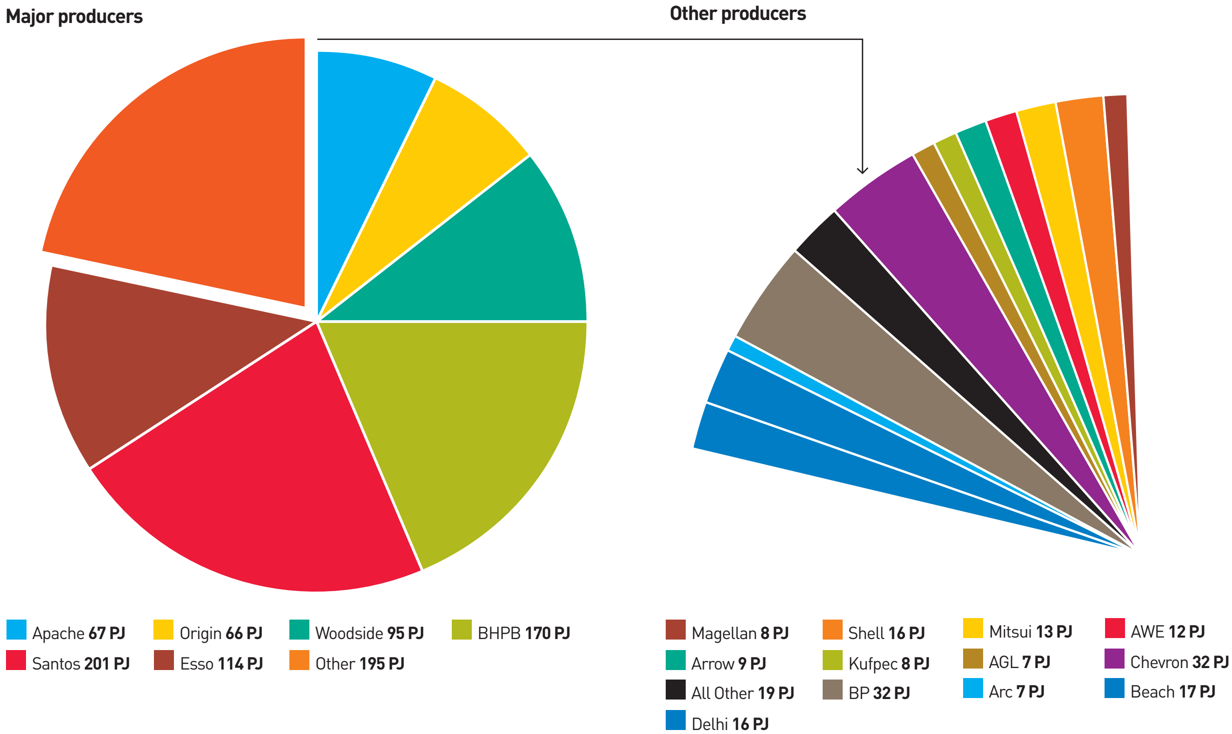
Source: Data provided by Geoscience Australia, 2006.

In general, the entities that now comprise the Australian petroleum resources industry fall into three categories. These are:

- International majors—multinational corporations with large production interests and substantial exploration budgets (e.g. BP, BHP Billiton, ExxonMobil, ChevronTexaco and Apache)
- Australian majors—major Australian energy companies with significant production interests and exploration budgets (e.g. Woodside Petroleum, Santos and Origin Energy)
- Juniors—smaller exploration and production companies, which may or may not operate production (e.g. AWE, Tap, Arrow, Queensland Gas Company and Arc). These companies may have a market capitalisation of over $1 billion.

Figure 8.15

Natural gas producers supplying the domestic market, 2006[1]



1. Other includes companies accounting for 4 per cent or less of domestic gas production. The group 'all other' comprises Anglo Coal, CalEnergy, Eastern Star, Enterprise Energy, Great Artesian, Helm Energy, Inpex, Molopo, Mosaic, Queensland Gas Company, Sentient Gas, Sunshine and Tap Oil.

Source: EnergyQuest, *Energy quarterly production report*, February 2007.

International majors tend to be involved in the larger offshore oil and LNG projects with Australian majors and smaller companies mainly focusing on onshore discoveries, often with a greater focus on natural gas sales for the domestic market. Santos, Origin Energy and Woodside Petroleum, for example, accounted for about 40 per cent of the domestic market and around a third of all gas produced in Australia in 2006. Junior explorers often play a significant role in higher risk greenfields exploration, such as the early phase of CSM developments in Australia. However, as illustrated by figure 8.14, smaller companies have been active offshore as well as onshore.

Gas producers

Gas production in Australia is relatively concentrated. While there are over 100 companies involved in gas and oil exploration only around 25 companies produce gas in Australia. Six major companies account for about 60 per cent of total gas production and almost 80 per cent of production for the domestic market. In 2006 Santos was the largest producer of gas for the domestic market accounting for 22 per cent of the market (figure 8.15). Other major producers were BHP Billiton (19 per cent), Esso (ExxonMobil) (13 per cent), Woodside (10 per cent), Apache (7 per cent) and Origin Energy (7 per cent). Other major players include BP, ChevronTexaco and Beach Petroleum[19] (which each make up 3–4 per cent of the domestic market) followed by other players such as Shell, Mitsui, and AWE (which each supply less than 2 per cent of the domestic market).

19 Beach Petroleum acquired Delhi in September 2006.

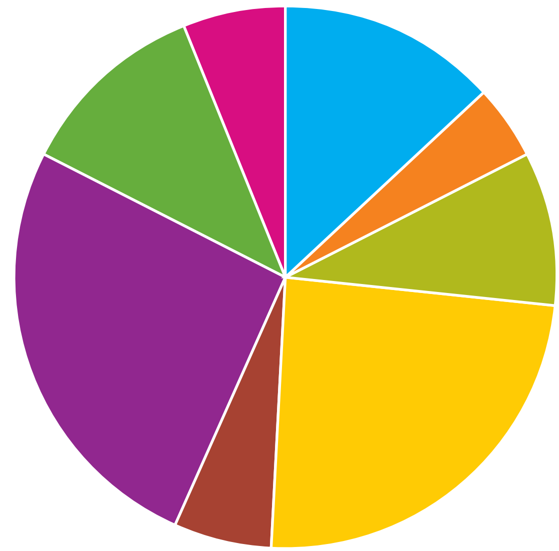
Gas plant at Moomba in South Australia

The development of CSM has seen the entry of a number of new players in exploration and production over the past 5–10 years. New entrants included a number of US companies (although most have now left Australia after little success with CSM development) as well as local companies including the Queensland Gas Company, Metgasco, Pure Energy, Sydney Gas, Hillgrove Resources, Bow Energy, Eastern Star, Sunshine Gas, and coal producers Anglo Coal and Xstrata. Santos, Origin Energy, AGL and Molopo also have involvement in CSM exploration and production.

There has been significant merger and acquisition activity in the CSM sector. Smaller companies are a common takeover target. For example, in 2005 Santos acquired Tipperary Oil and Gas (Australia) Pty Ltd and Sydney Gas Ltd sold 50 per cent of its assets to AGL and entered into a joint venture with AGL for the development of its tenements. In August 2006 Arrow completed a merger with CH4 Gas Limited. Following an unsuccessful takeover attempt by Santos the Queensland Gas Company formed a strategic partnership with AGL in which AGL obtained an initial 27.5 per cent stake in the company. The arrangement also provides for the two companies to enter into an agreement for AGL to purchase 540 petajoules of gas over 20 years, with an additional option of 200 petajoules. Prior to shareholder approval of AGL's cornerstone investment on 2 March 2007, US funds manager TCW, one of the world's biggest investors in CSM, made a takeover bid for the company.

The development of CSM and its impact on competition in the upstream gas industry is illustrated by figure 8.16. While significant gas producers such as Santos, BHP Billiton and Origin Energy accounted for most of the CSM produced in the year to December 2006, smaller players, including Sydney Gas (along with AGL), the Queensland Gas Company, and Arrow accounted for the balance (around 37 per cent).

Figure 8.16
Coal seam methane producers in Australia, 2006[1]



1. The other category is comprised of Mitsui, CS Energy, Molopo, Sentient Gas and Helm Energy.

Source: EnergyQuest, *Energy quarterly production report*, February 2007.

In terms of reserves Origin Energy and Santos are reported to have about 67 per cent of 2P reserves (proved and probable) with the balance mainly accounted for by the Queensland Gas Company and Arrow Energy. The smaller companies dominate the 3P reserves (proved, probable and possible) with Santos and Origin Energy having only 38 per cent of reported 3P reserves.[20]

20 Westside, 'Gas markets', <http://www.westsidecorporation.com/gas+markets.aspx>, viewed: 3 March 2007.

Joint venture arrangements

It is common for oil and gas companies to establish multi-company joint ventures, often at the exploration tenement application or bidding stage. Their purpose in establishing a joint venture is to help to manage risks and other costs. In these partnerships it is common for a significant producer (the operator of the joint venture) to hold a substantial or majority interest in the project with the remaining equity held by other companies including junior explorers. The joint ventures typically involve unincorporated contractual associations between the parties to undertake a specific business project in which the venturers contribute costs and receive output from the venture. They do not invest in a separate entity or receive a share of profits.

An example is the Cooper Basin partnership exploring petroleum tenements in South Australia. This comprises Santos (as operator) holding a 66 per cent interest, Beach Petroleum holding a 21 per cent interest and Origin Energy holding a 13 per cent interest.

The extent of competition within a particular basin depends in a large part on the number of fields developed and the ownership structure of the fields. Other factors include acreage management and permit allocation. Table 8.3 lists the main companies and joint venture arrangements in each major gas producing basin in Australia. There are currently about 16 ventures marketing gas in the south and eastern Australia. However, only about four producer groups are independent of the major producers (ExxonMobil, Santos, Origin Energy and BHP Billiton). In addition a single joint venture dominates production in the Cooper–Eromanga, Bass, and Gippsland basins. Competition is more diverse in the Carnarvon, Bowen–Surat and Otway basins.

In Western Australia there are about six key competing producer interests. In the Carnarvon there are around four key joint venture interests, although there are a number of common ownership interests across the ventures. Despite being focused on LNG production, the Woodside joint venture on the North West Shelf supplies about 60 per cent of the domestic Western Australian market. The John Brookes, Harriet and Griffin fields are not involved in LNG production. These fields produce around a third of Western Australia's domestic gas.

There are two producing groups operating in the Perth Basin, although production is dominated by Arc Energy, which wholly controls 64 per cent of the area under licence.

Gas for use in the Northern Territory is supplied from the Palm Valley and Mereenie fields in the Amadeus Basin. These fields are controlled by joint ventures involving Magellan and Santos. There is a joint venture with licences to produce in the Bonaparte and Timor Sea, but the venture is not currently supplying the local market. Supplies from the Bonaparte Basin for electricity generation are likely to commence in 2009 from the Blacktip project, which includes construction of a pipeline from the field to the Amadeus Basin to Darwin Pipeline.

In addition to existing production projects there are several gas projects that may begin in the next few years and could further add to competitive pressures. These projects are listed in table 8.4.

Table 8.3 Gas producers serving the domestic market in Australia, 2006[1]

NO.[2]	GAS FIELD	PRODUCERS BY MARKET AND GAS BASIN
16		SOUTHERN AND EASTERN AUSTRALIA
1		GUNNEDAH
		Eastern Star Gas Ltd
1		SYDNEY
	Cambden	Sydney Gas, AGL
1		BASS
	Yolla	Origin Energy, Aust Worldwide, MidAmerican Energy, Mitsui
2		GIPPSLAND
	Kipper	ExxonMobil (Esso), BHP Billiton[3]
	Patricia Baleen	Santos
3		OTWAY
	McIntee	Origin Energy, Beach Petroleum
	Minerva	BHP Billiton, Santos
	Casino	Santos, Mittwell Energy, AWE
1		COOPER-EROMANGA
		Cooper JV: Santos, Origin Energy, Beach Petroleum also others (Beach, Energy World, Drillsearch, Inland Oil, Magellan, CPC Energy)[3]
7		BOWEN-SURAT
		Arrow, AGL and others also Arrow and others (Beach, Qld Government)[3]
		Xstrata Coal
		Anglo Coal, Mitsui, Molopo, Helm
		Mosaic Oil and Santos
		Origin Energy and others (Mosaic, Santos, Ausam, Delta, Craig, Tri-Star)[3]
		Queensland Gas and others (Origin Energy, Sentient)[3]
		Santos and others (mainly Sunshine Gas and Origin Energy)[3]
6		WESTERN AUSTRALIA
4		CARNARVON
	Harriet	Apache, Kufpec, Tap Oil also Apache, Pan Pacific, Santos, Tap Oil[3]
	John Brookes	Apache, Santos
	North West Shelf	North West Shelf JV: Woodside, Royal Dutch Shell, Chevron, BHPB, BP[3]
	Griffin	BHPB, ExxonMobil, Inpex
2		PERTH
	Dongara/Yardarino; Woodada	Arc Energy
	Beharra Springs	Origin Energy, Arc Energy
1		NORTHERN TERRITORY
		AMADEUS
	Meerenie and Palm Valley	Magellan, Santos

1. Not all fields may have produced gas in 2006. 2. Represents the number of key producer groups operating in each basin and region. 3. Represents the aggregation of a number of production licences with similar joint venture arrangements.

Source: GPInfo, *Petroleum Permits of Australasia*, Encom Petroleum Information Pty, Ltd, North Sydney 2006; Websites of the Department of Industry and Resources (WA); Department of Infrastructure Energy and Resources (Tas); Department of Natural Resources and Water (Qld); Department of Primary Industries (NSW); Department of Primary Industries, Fisheries and Mines (NT); Department of Primary Industries and Minerals (Vic); Primary Industries and Resources South Australia (SA).

Table 8.4 Gas projects with potential to supply the domestic market

PROJECT	BASIN	OPERATOR (OTHER COMPANIES)	INITIAL PRODUCTION	STATUS AT FEBRUARY 2007
DOMESTIC GAS PROJECTS				
Thylacine	Otway	Woodside (Origin, Benaris, CalEnergy)	60 PJ a year	Production is due to start in late 2007.
Henry	Otway	Santos (AWE, Mitsui)	na	Front End Engineering Design (FEED) underway. Possible gas production by early 2009.
Trefoil/White Ibis	Bass	Origin (AWE, CalEnergy, Wandoo)	na	Development scoping studies being planned.
Kipper	Gippsland/Kipper	Exxon Mobil (BHP, Santos)	30–40 PJ a year	Participants have agreed to enter FEED. Gas production expected to start by 2010.
Basker-Manta	Gippsland	Anzon (Beach)	20	In FEED stage. Production planned for first half of 2009.
Turrum	Gippsland	Exxon Mobil (BHP)	na	Under consideration.
Longtom	Gippsland	Nexus	30 PJ a year	Possible production by the second half of 2008.
Tipton West	Surat	Arrow (Beach)	10 PJ a year	Commenced February 2007.
Argyle	Surat	QGC (Origin)	7 PJ a year	First gas likely March 2007.
Blacktip	Bonaparte	ENI	24 PJ a year	Production planned from 2009.
Reindeer	Carnarvon	Apache (Santos)	na	Feasibility study underway. Possible production from 2010.
LNG PROJECTS WITH DOMESTIC GAS POTENTIAL				
NWS JV Fifth Train	Carnarvon	Woodside plus partners	240 PJ a year	Increased capacity from the end 2008. Already a major gas producer for the domestic market.
Gorgon	Carnarvon	Chevron (Shell, Exxon Mobil)	550 PJ a year	In FEED stage.
Pluto	Carnarvon	Woodside	270–330 PJ a year	Possible production, including for the domestic market, by the end of 2010.
Darwin LNG	Bonaparte	ConocoPhillips	190–330 PJ a year	LNG expansion targeted for 2013. Under the right commercial conditions the project could supply the domestic market.
STALLED DOMESTIC GAS PROJECTS				
PNG	PNG	Exxon Mobil (Oil Search, AGL, Merlin)	na	Currently deferred in favour of LNG.
Petrel Tern	Bonaparte	Santos	na	At development proposal stage.

na not available.

Source: Information provided by EnergyQuest.

8.7 Gas wholesale operations and trade

Gas processing facilities are connected to end-use markets by gas transmission pipelines and distribution systems. Consequently, trade in gas comprises two distinct but inter-related wholesale components:

- gas sales—producers selling gas directly to major industrial and power generation customers and to energy retailers, who aggregate customer loads for on-sale to smaller customers
- gas transport—transmission and distribution pipeline service operators selling capacity and transport services to energy retailers and major gas users.

Unlike electricity, gas production and delivery is not instantaneous and gas can be stored in gathering and transmission pipelines (known as linepack) and in depleted reservoirs or in liquefied form. It is economic to store gas only to meet peak demand requirements or for use in emergencies.

Natural gas pipelines are subject to minimum and maximum pressure constraints. The quantity of gas that can be transported in a given period varies with diameter and length of the pipeline and the difference in pressure between the two ends. The greater the pressure differential, the faster gas will flow. These features mean that gas deliveries must be scheduled. In Victoria gas is generally produced and delivered in 6–8 hours because most demand centres are less than 300 kilometres from gas fields. Gas delivered from the Cooper Basin into New South Wales can take 2–3 days because the gas must be transported more than 1000 kilometres. Deliveries on the Eastern Gas Pipeline are faster. Time lags between production and delivery of gas are also substantial for some customers in Western Australia and the Northern Territory.

Given the time taken for deliveries, commercial operations mainly focus on managing daily flows of gas, with additional longer or shorter elements as appropriate. Gas retailers and major users estimate requirements for the day ahead and nominate that quantity to their producers and pipeline operators, subject to any pre-agreed constraints on flow rates and pipeline capacity.

Each day producers inject the nominated quantities of gas into the transmission pipeline on behalf of their customers. Transmission pipeline operators deliver the gas to customers or distribution networks, which in turn deliver the gas to retailers' customers.

There is typically a difference between retailer nominations for injections and actual withdrawals from the system, creating imbalances. A variety of systems operate in Australia for dealing with imbalances. In some systems imbalances are corrected over time through adjustments to future gas scheduling and in others imbalances are rectified through cash transfers, usually determined on a daily basis and reconciled monthly. The independent market operator in Victoria—VENCorp—operates a spot market for managing system imbalances and constraints on the Victorian Transmission System (VTS). The spot market also provides a transparent mechanism for short-term trading in gas (see p. 245 for details).

Gas supply arrangements

The fact that all stages of the production chain require large sunk investments means that commercial arrangements in the sector tend to be dominated by confidential long-term contracts for gas supply and transport both in Australia and overseas (see box 8.2 for an overview of gas contracting and trading arrangements in the United States and United Kingdom). Typically in Australia contracts extend for 10–15 years, but may extend for 20–30 years for riskier and high cost ventures. During 2006 there has been a considerable tightening in the supply of gas in Western Australia. The Economic Regulation Authority in Western Australia reports that gas producers are only offering contracts with a maximum term of five years with volumes restricted to about 10 terajoules a day.[21]

21 ERA, *Gas issues in Western Australia,* Discussion paper, Perth, 2007.

Box 8.2 Gas contracting and trade in the United States and United Kingdom

United States

The United States is the largest market for natural gas in the world. Gas and pipeline capacity are typically provided under long-term bilateral contracts for services. Gas is sold in an unregulated market while transmission services are subject to regulated price caps. Under federal regulation, pipeline operators must establish electronic bulletin boards to facilitate the trading of capacity, known as 'capacity release'. Shippers holding capacity rights can resell 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.

Gas trading in the United States largely occurs at hubs, where spot markets have emerged for managing short-term fluctuations in supply. The Henry Hub in Louisiana, which serves the New York area, is the largest trading centre. It provides a spot market for both gas and pipeline capacity. In addition, the New York Mercantile Exchange operates a natural gas futures market at Henry Hub. Prices are quoted for standard gas contracts, delivered to Henry Hub on specific dates.

United Kingdom

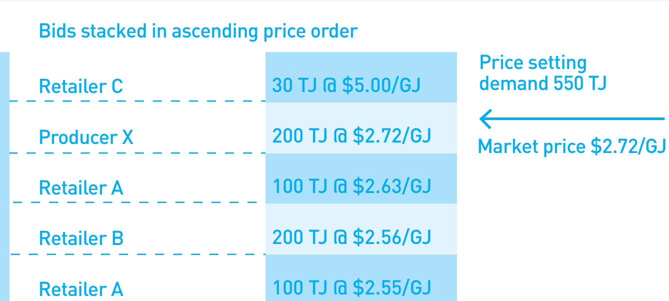
The United Kingdom is the largest natural gas market in Europe. Gas is sold under long-term bilateral contracts. The United Kingdom operates a regulated National Transmission System with services provided by a single independent operator—National Grid Transco. Transmission service prices are determined by the regulator using a 'building block' approach similar to that adopted in Australia. Services are subject to a network code, which establishes a common set of non-discriminatory rules for all industry players and forms the basis of arrangements for shipping gas.

Pipeline capacity is allocated annually through auctions at each of the main onshore gas receiving terminals. The auctioned rights provide monthly capacity entitlements. Shippers trade in capacity. In addition, National Grid Transco conducts daily auctions in which it acts as the counterparty to all transactions based on the posting of buy and sell offers. Natural gas spot markets have emerged at several of the onshore terminals. Spot market trading is bilateral or on a brokerage basis.

Source: The Allen Consulting Group, *Options for the development of the Australian wholesale gas market*, Report to the Ministerial Council on Energy Standing Committee of Officials—Gas Market Development Working Group, Final report, 2005.

Box 8.3 Determining the market clearing price in the Victorian spot market

In this example, a 550 TJ demand sets the price for gas on the day. In the absence of any constraints, this demand can be met by scheduling all of the gas offered into the wholesale market by retailers A and B, and 150 TJ of the gas offered by producer X.



Source: Vencorp, *Guide to the Victorian gas wholesale market*, 2006.

Contracts with gas producers include 'take-or-pay' clauses with the purchaser paying for a minimum quantity of natural gas each year irrespective of whether the purchaser actually takes delivery of it.

Two systems operate for bulk transmission of gas in Australia—'contract carriage' and 'market carriage'. Under the contract carriage system a gas shipper contracts for pipeline capacity on a 'take-or-pay' basis. The shipper pays for minimum use of a pipeline (expressed as $/maximum daily quantity (MDQ)) each year regardless of whether the capacity is used. Essentially, shippers purchase a transmission right. Capacity charges generally account for most of the cost of shipping gas, although volume charges for the actual amount of gas transported and other ancillary charges apply.

Under a market carriage system shippers do not contract for pipeline capacity. Rather capacity is assigned to users with shippers paying for capacity on a pro-rata basis. This is the system operated for carriage on GasNet's VTS. The market carriage system was introduced in the late 1990s to provide a more flexible arrangement for operating in a deregulated market. This was considered necessary because of the complexity of the interconnected network, which has five injection points and multi-directional gas flow and limited linepack. It also accommodates the fact that retailers operating in a competitive environment do not have a guaranteed customer base over the long term, potentially making it difficult to enter into contracts for supply.

Victorian spot market

The spot market operated by VENCorp for gas transported on the VTS operates under a net pool arrangement (that is, for increases and decreases in daily supply). Market participants (mostly retailers) inform VENCorp of their nominations for gas one and two days ahead of requirements. The spot market is then used to respond to changes in customer demands across a gas day and by VENCorp for gas balancing.

VENCorp stacks the bids and selects the least cost bids from participants to match demand across the whole market and establish the market clearing price (box 8.3). Market participants may submit offers for increments or decrements (increases or decreases) to the quantity injected or withdrawn at connection points. Each offer may specify several prices and corresponding quantities of injections or withdrawals that the market participant is prepared to implement if the market price reaches the specified value.

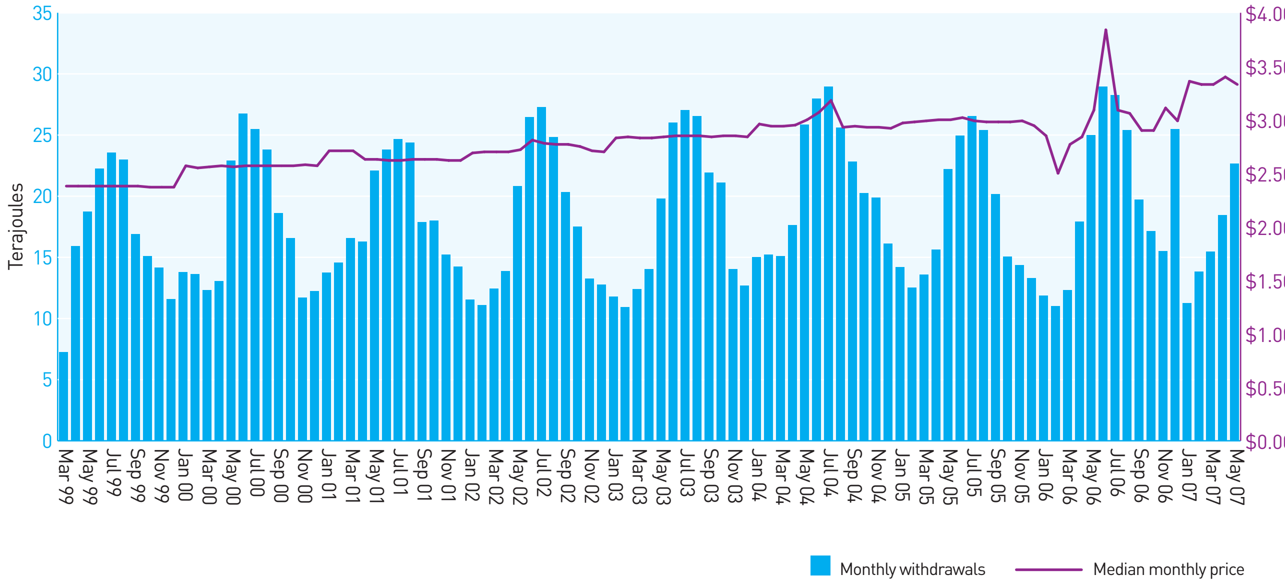
If the spot market price falls below a retailer's contract price, the retailer may take the position that it is better to reduce its own injections of gas and to buy from the spot market. If the spot price for gas rises, then the retailer may wish to inject more gas than it needs for its own customers and sell it through the spot market. As an alternative, a retailer may establish an 'interruptible' contract with a large customer and submit a withdrawal increment or decrement offer structured in such a way that if the spot price for gas rises above a certain price then that customer's use of gas is interrupted or reduced. Any excess gas obtained through such an arrangement can be sold on the spot market.

The spot market for gas in Victoria allows market participants to enter into financial contracts to manage their physical spot price exposure. However, available information suggests that such trading is very limited with all financial contracts conducted on a bilateral basis. There is no formalised market mechanism or brokering service for facilitating trades.

Around 10–20 per cent of gas transported on the VTS is traded through the spot market with the rest sold under commercially negotiated contracts. The price of the gas traded is established by VENCorp at the daily ex-post market clearing spot price based on completed trades.

Figure 8.17

Prices and withdrawals on the Victorian spot market



Source: VENCorp, 'Market reports', http://www.vencorp.com.au/html/index.htm, viewed: 2 November 2006.

Figure 8.17 plots monthly gas withdrawals and the median monthly spot price for gas from March 1999 (market start) to May 2007. It shows that the spot market has been characterised by low variability in prices and typically trading activity is highest during the winter peak period.

While prices on the spot market are relatively stable there are occasional troughs and spikes in the spot market price. For example, while in 2006 the average daily spot price was about $3.00, it fell to $2.21 on 15 March and achieved a high of $6.04 on 10 June. For the last trading interval on 16 April 2007 the spot price rose to $35.49. Under the Victorian Gas Industry Market and System Operations Rules VENCorp is required to monitor daily trading activity within the market to ensure that trading occurs within the rules. It assesses and reports on significant pricing or settlement events to determine whether the activities of market participants may have significantly affected market outcomes. To date VENCorp has found that price spikes in the market have been due to operational and market requirements, often relating to severe weather conditions.[22] It has not found evidence of anti-competitive conduct.

Prices on the spot market were more volatile during 2006 than in previous years. A range of factors may have contributed to this including:

- the start of new supplies (e.g. Casino and Bass gas)
- changes to contractual positions
- unusual weather events (for example, in 2006 April and May were warmer than usual, while June was unseasonably cold).

Stemming from VENCorp's 2004 *Victorian gas market pricing and balancing review*, reforms to the gas market began in February 2007 with ex ante pricing, within day rescheduling and rebidding being introduced. The spot price is declared ex ante and revised every four hours up until 10 pm EST. This change adds flexibility, promotes incentives to respond to the spot price and provides clearer and more certain pricing signals. It also brings the gas and electricity markets into closer alignment.

The VENCorp review proposed additional reforms that may be implemented at a later stage. Initial reforms could involve the introduction of 'transmission rights', integrated with a change to structure of GasNet tariffs.

22 For details see VENCorp significant pricing events reports at http://www.vencorp.com.au/html/index.htm.

This proposal is intended to give GasNet greater investment and revenue certainty and address 'free-rider' problems by providing incentives for shippers to obtain transmission rights and invest in expansions. The key elements of the proposed changes are:

- a move from predominantly usage-based tariffs to predominantly capacity and contract-based charges
- differentiated usage charges tied to transmission rights involving higher charges for 'unauthorised' or spot usage relative to usage charges for rights holders.

Further enhancement of the market-based system to promote investment incentives, transparency and efficiency could involve:

- introducing locational (hub-based) within-day pricing to provide clearer pricing signals for pipeline constraints, which should enhance investment incentives and promote transparency and efficiency
- replacing transmission rights with biddable capacity rights to provide a market system for day-to-day sale of spare capacity.

Secondary trading

Secondary trading in gas refers to trading of existing contracted supplies and transport capacity. Most secondary trading is conducted through confidential bilateral contracts tailored to the issues specific to each transaction. For example, Firecone notes that shippers using the Moomba to Adelaide Pipeline System negotiate between themselves to secure additional capacity as required.[23]

Backhaul

Backhaul is used in uni-directional pipelines to provide for the 'notional' transport of gas in the opposite direction of the physical flow of gas in a pipeline. It is achieved by redelivering gas at a point upstream from the contracted point of receipt.

Backhaul provides an opportunity for trading in pipeline capacity with pipeline operators competing for the sale of their spare capacity (interruptible supply) with sales of (firm) capacity that existing shippers release for trade. Backhaul arrangements are most commonly used by gas-fired electricity generators and industrial users that can cope with intermittent supplies. For example, in November 2006, Epic Energy signed a six-year backhaul contract on the South West Queensland Pipeline valued at $67 million. While Epic Energy did not reveal further details due to confidentiality agreements, Citigroup analysis suggests that the contract is for about 30–35 petajoules a year with the gas supplied from Santos's Fairview and/or Origin Energy's Spring Gully CSM fields for sale to customers on the Carpentaria Pipeline in Mt Isa.[24] This deal follows the decision not to proceed with the PNG pipeline.

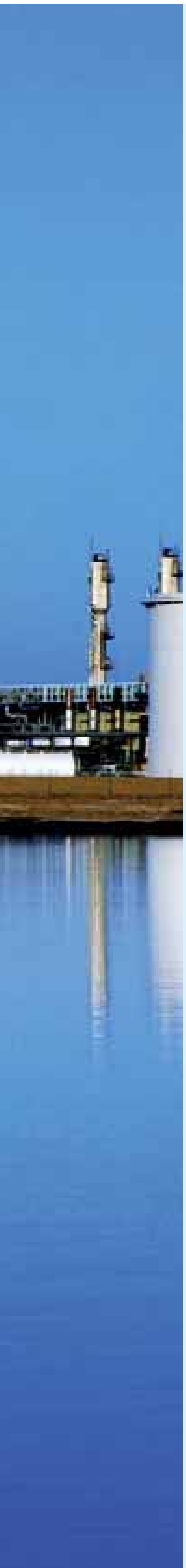
Gas swaps

A gas-for-gas swap is the exchange of gas at one location for the equivalent amount of gas delivered at another location. Swaps are a form of secondary trading with payment being made through the transfer of rights to the physical gas commodity.

The available anecdotal evidence suggests that swaps are reasonably common in Australia, but are conducted only on a minor scale. Most transactions are for a small volume of gas and account for only a small share of total sales.[25] Typically swaps are short-term, lasting for a few months, although there are some examples of multi-year agreements, such as the swap between Origin Energy and South West Queensland Gas Producers (box 8.4).

Firecone reports that shippers use swaps to provide flexibility for dealing with both expected and unexpected mismatches between supply and demand for gas and transport capacity. Swaps also can help shippers to overcome physical limitations imposed by the direction or capacity of gas pipelines and provide significant cost savings by reducing or delaying the need to invest in pipeline capacity.[26]

23 Firecone Ventures, *Gas swaps*, Report prepared for the National Competition Council as part of the NCC occasional series, Melbourne, 2006.
24 Citigroup Global Markets, 'Hastings Diversified Utilities Fund', Company in-depth, 23 February 2007.
25 Firecone Ventures, 2006. See footnote 23.
26 Firecone Ventures, 2006. See footnote 23.



Box 8.4 Gas swap between Origin Energy and South West Queensland Gas Producers

In 2004 the South West Queensland Gas Producers entered into an agreement with Origin Energy to swap gas between Queensland and the Moomba Gas Hub. Under the arrangement Origin Energy delivers gas produced at its central Queensland fields to the South West Queensland Gas Producers at Roma in Queensland for use in meeting part of their customer requirements in south-east Queensland. In return the producers redirect (swap) an equal quantity of their Cooper Basin produced gas to the Moomba Gas Hub, which Origin Energy can use to meet its supply commitments in south-eastern Australia (see map).

The agreement extends to 2011. It involves up to 200 petajoules of gas a year, with a mechanism to increase these quantities. Contracting parties benefit from the deal because:

- Origin Energy is able to delay or eliminate the need to construct major additional pipeline infrastructure.
- The South West Queensland Gas Producers earn extra revenue from the swap fee (and incremental processing at the Moomba Gas Hub, which recovers higher levels of liquids than its Ballera facilities).

Source: Santos, 'Cooper Basin and Origin in major gas swap agreement', Media release, 6 May 2004, http://www.originenergy.com.au/files/gasswapagreement_2.pdf; Firecone Ventures, *Gas swaps*, Report prepared for the National Competition Council as part of the NCC occasional series, Melbourne, 2006.

VicHub

A gas hub is a convergence or interconnection point for alternative gas supplies (often with associated storage capacity) and where gas trades often occur. Hubs exist at Moomba, Wallumbilla and Longford.

VicHub was established in February 2003 at Longford and is currently owned by Alinta. It connects the Eastern Gas Pipeline, Tasmania Gas Pipeline and VTS. This connection allows for trading of gas between New South Wales, Victoria and Tasmania.

VicHub is not a formal trading centre in the sense that it does not currently provide brokering services. Rather it buys and sells gas between the various regions to profit from price differentials, posting public buy and sell offers.

Emergency management

Following the disruptions at the Longford gas processing plant in 1998 and the Moomba plant in 2004 Australian governments agreed to a non-legally binding protocol for managing major gas supply interruptions occurring on the interconnected networks. Such emergencies are to be managed in accord with the Memorandum of Understanding in Relation to National Gas Emergency Response Protocol (Including Use of Emergency Powers) October 2005, which seeks to provide for:

> …more efficient and effective management of major natural gas supply shortages to minimise their impact on the economy and the community, and thereby contribute to the long term community objective of a safe, secure and reliable supply of natural gas. [p. 5]

The memorandum of understanding established a government–industry National Gas Emergency Response Advisory Committee (NGERAC) to implement the protocol. Its primary role is to report periodically to ministers on the risk of gas supply shortages and options for reducing or averting potential shortages. It must also report on general requirements for communications, information provision and the roles of government and industry in the event of a major shortage of natural gas. The committee has established a Gas Emergency Protocol Working Group to develop an emergency response mechanism. The working group has published an options paper that examines options for managing an emergency including institutional arrangements, required legislative changes and communication protocols.

In the event of a major gas supply shortage the protocol requires:

- NGERAC to be convened to advise the Ministerial Council on Energy (MCE) and jurisdictions on the most efficient and effective way to manage the shortage
- as far as possible, that commercial arrangements be allowed to operate to balance gas supply and demand and maintain system integrity
- government intervention in the market and the use of emergency powers to occur as a last resort, and preferably, only after considering advice from the NGERAC and after reasonable efforts to consult with other interconnected or affected jurisdictions.

8.8 Gas market development

Despite the significant development of gas infrastructure and retail markets in the past decade, gas sales in Australia remain largely based on long-term bilateral contracts. Lack of price transparency (except in Victoria) and consistent and simple short-term trading mechanisms increase the difficulties of managing financial risk and security of supply and may raise barriers to entry.

To address this issue the MCE established the Gas Market Leaders Group (GMLG)[27] in November 2005 to develop a plan to deliver on the MCE's objective for a 'competitive, reliable and secure natural gas market delivering increased transparency, promoting further efficient investment in gas infrastructure and providing efficient management of supply and demand interruptions'.

The GMLG submitted its plan to the MCE on 29 June 2006, in which it recommended that the MCE:

- establish a bulletin board covering all major gas production fields, major demand centres and transmission pipeline systems
- direct the GMLG to proceed with detailed design of a short-term trading market for all states (except Victoria, which already has a gas spot market)
- establish a national gas market operator to manage both the wholesale and retail gas markets throughout Australia. The operator should replace the gas retail market functions of GMC and REMCo and the gas functions of VENCorp and be responsible for:
  - administering the bulletin board and, if established, the short-term trading market
  - providing advice to NGERAC in the collection, maintenance, publication and analysis of gas system information and to provide technical advice on managing supply constraints
  - producing an annual national gas supply/demand statement.[28]

The GMLG also proposed that the initiative be jointly funded by industry and government. It estimates that design and implementation of a bulletin board and a trading market would cost around $3.2 million. Industry would face initial set-up costs of about $9 million with ongoing annual costs of around $1.7 million. As an interim measure the GMLG would continue until the Gas Market Operator is established, to ensure the recommendations are implemented.

The GMLC's recommendations are supported by the Energy Reform Implementation Group (see appendix A). At its 27 October 2006 meeting, the MCE accepted the recommendations of the GMLG. The MCE requires the GMLG to develop the bulletin board in conjunction with the NGERAC so that it serves the purposes of both the gas market and the National Gas Emergency Response Protocol that NGERAC manages.

The GMLG has established a steering committee to manage the development of a bulletin board and further consider the design of a short-term trading market. Details of the group's proposal for the bulletin board and the short-term trading market are provided in the following sections.

Bulletin board

The GMLG proposes that a national bulletin board (website) be established to facilitate improved decision-making and gas trading and provide information to help manage emergencies and system constraints. The bulletin board would cover all major gas production fields, major demand centres and transmission pipeline systems. Its primary purpose would be to provide readily accessible and updated information to end-users, smaller or potential new entrants, and market observers (including governments), on the state of the market, system constraints and market opportunities. It proposes that the bulletin board:

- publish information on physical and available pipeline capacity, pipeline tariffs, production and storage capacities and three-day demand forecasts
- support voluntary posting of buy/sell offers
- provide key contact details for pipeline operators, producers, storage providers, shippers and retailers.

The GMLG is working towards making the bulletin board operational by the first half of 2008.

27 The group comprises 12 gas industry representatives and an independent chairperson.

28 Gas Market Leaders Group, *National gas market development plan*, report to the Ministerial Council on Energy, 2006, http://www.mce.gov.au/assets/documents/mceinternet/FinalGMLGReport20060707135526.pdf

Short-term trading market

The GMLG proposes that a short-term trading market be designed for all state and territory pipeline systems. It proposes that initially the short-term trading market be established in New South Wales and South Australia to replace existing gas balancing arrangements.

The short-term trading market is intended to facilitate daily trading by establishing a mandatory price-based balancing mechanism at defined gas hubs. A daily market-driven clearing price will be determined at each hub, based on bids by gas shippers to deliver additional gas at the hub.

The difference between each user's daily deliveries and withdrawals of gas at the hub will then be settled by the market operator at the clearing price. The GMLG believes that its recommended market mechanisms will provide price signals to shippers and users and stimulate trading over interconnected pipelines and demand-side response by users.

The short-term trading market is intended to operate in conjunction with longer-term gas supply and transportation contracts. It will provide an additional option for users to buy or sell gas on the short-term market without contracting for delivery and also allow contracted parties to manage short-term supply and demand variations to their daily contracted quantities.

The GMLG intends to make a decision on whether to proceed with development of a short-term trading market by October 2007. Should the short-term trading market proceed it would likely be operated by the National Energy Market Operator that COAG has agreed to establish to replace NEMMCO and the current gas market operators.

Futures markets

The risk of participating in a commodity market can usually be hedged using physical or financial means. However, a futures gas market tends to develop only after the physical gas market reaches a certain level of maturity and a significant amount of natural gas is traded under transparent short-term contracts, such as has occurred in the United States and United Kingdom.

There is no futures market for gas in Australia at the moment and current opinion suggests that there is little prospect that a market will develop soon. The decision to implement a bulletin board and consider extending short-term trading in other states and territories may facilitate future development of a market for financial risk-hedging instruments (forward, futures, swap and option contracts).