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The Gas Supply Chain in Eastern Australia

A report to the Australian Energy Market Commission

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Glossary

ABARE	Australian Bureau of Agricultural and Resource Economics
ACCC	Australian Competition and Consumer Commission
ACQ	Annual Contract Quantity
AER	Australian Energy Regulator
AMDQ	Allocated Maximum Daily Quantity
BB	Bulletin Board
CNG	Conventional Natural Gas
CSM	Coal Seam Methane
EGP	Eastern Gas Pipeline
ERIG	Energy Reform Implementation Group
ESCOSA	Essential Services Commission of South Australia
FRC	Full Retail Competition
GA	Geoscience Australia
GJ	Gigajoule (1,000,000,000 joules)
GMLG	Gas Market Leaders Group
MAP	Moomba to Adelaide Pipeline
MCE	Ministerial Council on Energy
MCMPR	Ministerial Council on Mineral and Petroleum Resources
MDQ	Maximum Daily Quantity
MHQ	Maximum Hourly Quantity
MSOR	Market System Operation Rules (Victoria)
MSP	Moomba to Sydney Pipeline
PJ	Petajoule (1,000,000 Gigajoules)
PTS	Principal Transmission System
STTM	Short Term Trading Market
TJ	Terajoule (1,000 Gigajoules)

1. Introduction

NERA Economic Consulting has been asked by the Australian Energy Market Commission (AEMC) to provide an overview of the wholesale gas and electricity markets and to identify the issues that it should consider when assessing the influence of these wholesale markets on competition within the retail gas and electricity markets. We understand that this work is being undertaken as part of the AEMC's broader review of the effectiveness of retail competition in electricity and gas markets in each of the National Electricity Market jurisdictions.

To assist the AEMC with this review separate reports have been prepared for both gas and electricity. This report focuses on the gas supply chain in eastern Australia while its sister report focuses on the wholesale electricity market.

To understand the influence that the gas supply chain may have on competition at the retail level it is important to understand that gas supply and transportation costs account for as much as 90 per cent of the price paid by residential customers.[1] It is also important to understand that while there have been a number of developments in the upstream segment of the gas supply chain and the number of supply options available in each jurisdiction has increased, the eastern Australian gas 'market' continues to be characterised by discrete localised sub markets. The prices prevailing in these sub markets are therefore determined by local demand and supply conditions. Appreciating the disparate nature of the eastern Australian 'market' is therefore critical to understanding the diversity of conditions faced by retailers operating in different jurisdictions and the influence the gas supply chain may have on retail competition in each jurisdiction.

The remainder of this report examines each element of the gas supply chain and has been structured in the following manner:

- Section 2 examines gas consumption in eastern Australia and the projected growth in this area;
- Section 3 focuses on the upstream segment of the gas supply chain in eastern Australia commencing with a description of the sources of gas in eastern Australia. This section then moves on to consider the physical and economic characteristics of gas exploration and production which influence both the structure of the market and the price a producer is willing to accept for gas. This section also examines the prevailing market structure and the factors influencing this structure and concludes by providing a description of gas supply contractual arrangements and the determinants of gas prices;
- Section 4 focuses on the transmission segment of the gas supply chain commencing with an overview of the transmission pipelines that currently transport gas from the basins to capital cities in eastern Australia. This section then examines the market structure in this segment of gas transmission before providing an overview of the services offered by transmission pipelines. This section concludes by examining the inextricable link between

[1] IPART, Final Report: Review of the Delivered Price of Natural Gas to Tariff Customers Served from the AGL Gas Network in New South Wales, February 2001, pg. 29 and Productivity Commission, Review of the Gas Access Regime, August 2004, pg. 46.

the conditions prevailing in the transmission and production segments of the supply chain and sets out the factors considered by a retailer when deciding upon the commercial viability of alternative sources of supply;

§ Section 5 describes the distribution systems currently operating in each of the capital cities in eastern Australia and sets out the market structure in this segment. An overview of the services offered on these pipelines and tariff structures is also set out in this section;

§ Section 6 provides an overview of the risk management tools that are used by buyers to ameliorate the risks they face when purchasing gas from the wholesale market and entering into transportation contracts with transmission pipeline owners;

§ Section 7 sets out the current structure of the retail market in each capital city and the factors that have influenced that structure. This section also outlines the role of retail market operators and sets out the full retail contestability timetable for each jurisdiction;

§ Section 8 provides a summary of the recent reviews that have been undertaken of the wholesale gas market and outlines the proposed changes in this area; and

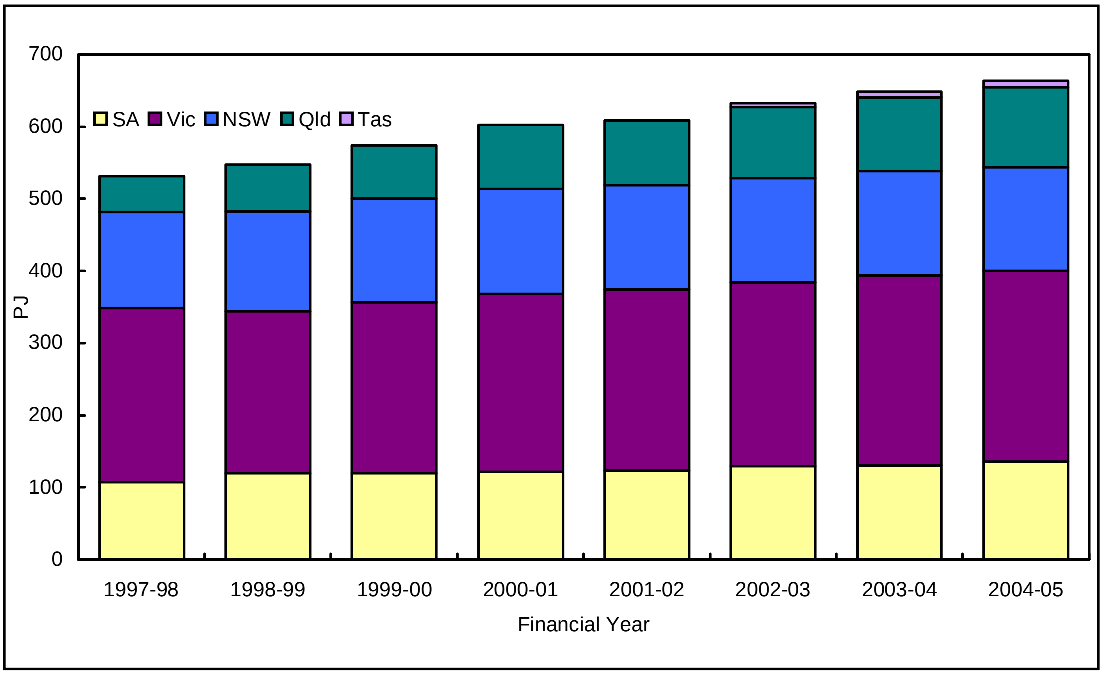
§ Section 9 outlines the factors that should be considered when examining the influence that upstream production and transportation segments of the gas supply chain have on retail competition.

2. Gas consumption in eastern Australia

2.1. Historic estimates of consumption[2]

Consumption of gas in eastern Australia increased by 25 per cent (or 3.2 per cent on an annualised basis) over the period 1997-98 to 2004-05 from 531 PJ to 664 PJ.[3] Over this period New South Wales[4] and Victoria have experienced similar growth rates of 8 and 9 per cent respectively while South Australia's consumption has grown by 28 per cent and Queensland's consumption has more than doubled (increasing by 121 per cent). Following the completion of the Tasmanian Gas Pipeline in 2002 consumption in Tasmania has begun to increase. Figure 2.1 illustrates the growth in consumption across each of the states.

Figure 2.1: Consumption of gas by State



Source: ABARE, Australian Energy Consumption and Production 1974-75 to 2004-05, Table c.
Note: The New South Wales estimates includes consumption in the Australian Capital Territory.

Examining Figure 2.1 it is clear that Victoria has been the largest consumer of gas in eastern Australia over the period 1997-98 to 2004-05, followed in declining order by New South Wales, South Australia, Queensland and Tasmania. Although this order has been maintained over the period, the share of total consumption accounted for by each state has changed over the period (see Figure 2.2).

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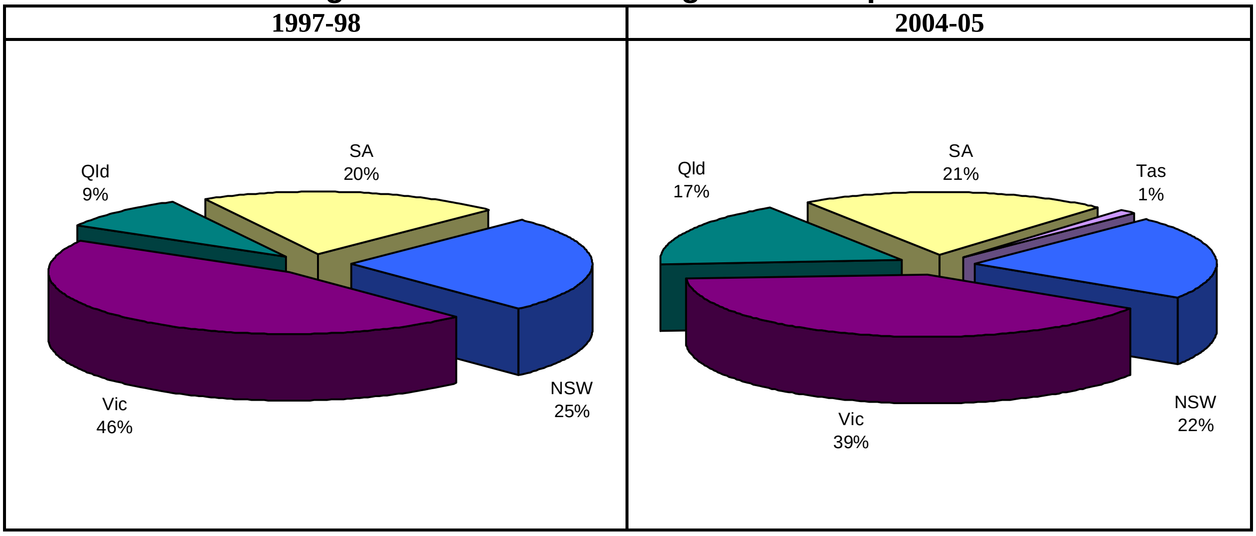
2 The information contained in this section has primarily been sourced from statistics prepared by ABARE. See ABARE, Australian Energy Consumption and Production, 1974-75 to 2004-05, Tables c and f.

3 ABARE, Australian Energy Consumption and Production, 1974-75 to 2004-05, Tables c and f.

4 ABARE's estimates for New South Wales include consumption in the Australian Capital Territory.

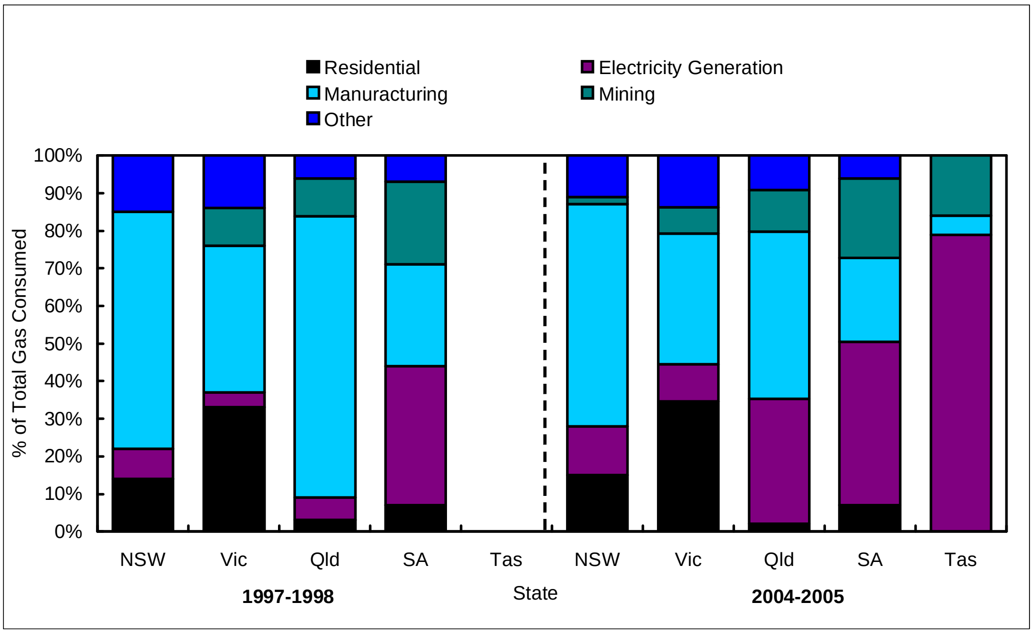
Figure 2.2: Share of total gas consumption



Source: ABARE, Australian Energy Consumption and Production 1974-75 to 2004-05, Table c.
Note: The New South Wales estimates include consumption in the Australian Capital Territory.

Figure 2.3 compares the composition of demand across the states over the period 1997-98 to 2004-2005. In South Australia, Tasmania and Queensland a large proportion of the gas is consumed for electricity generation, while in Victoria and New South Wales the manufacturing and residential sectors represent a large proportion of the gas consumed. The mining and manufacturing sectors in South Australia and Queensland are also significant consumers of gas. Comparing the composition of demand in 2004-05 to that in 1997-98 it is clear that electricity generation accounts for a greater share of demand across all of the states than it has historically. This is particularly the case in Queensland where electricity generation now accounts for 33 per cent of total consumption compared to just 6 per cent in 1997-98.

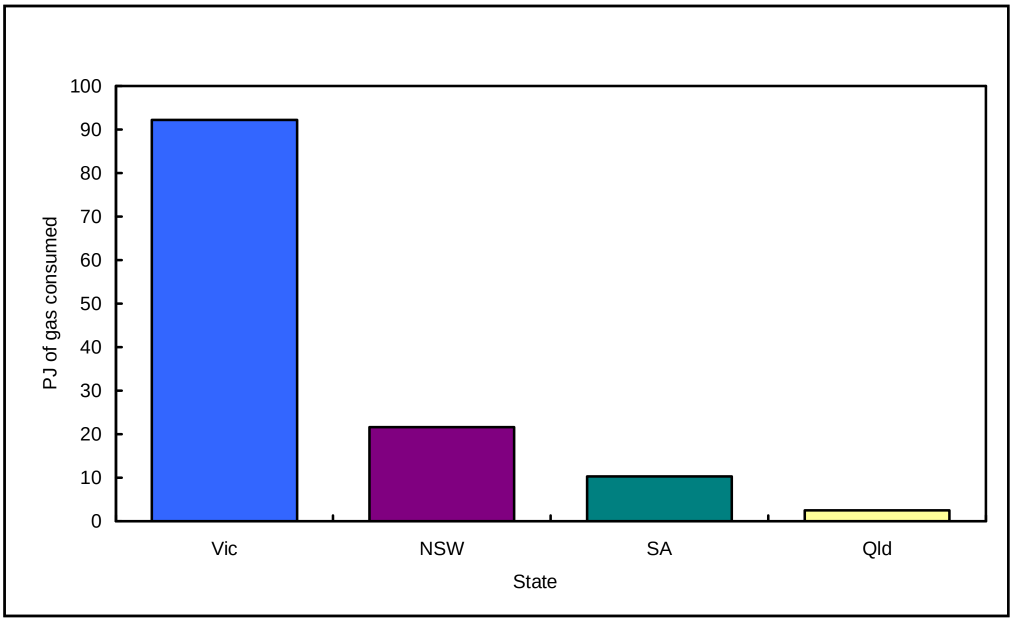
Figure 2.3: Composition of gas demand



Source: ABARE, Australian Energy Consumption and Production 1974-75 to 2004-05, Table F
Note: The New South Wales estimates include consumption in the Australian Capital Territory.

Comparing the proportion of gas consumed by the residential sector in each state (Figure 2.3 and 2.4) it is apparent that Victorian residents are significant consumers of gas accounting for 35 per cent of gas consumed in 2004-05 (92 PJ). Across the other states residential consumption in New South Wales accounted for 15 per cent (21 PJ), South Australia 7 per cent (10 PJ) and Queensland 2 per cent (2 PJ). The first stage of the distribution system in Tasmania was completed in July 2005 and thus there was no residential consumption in Tasmania over 2004-05. This is expected to change over the medium term as residential customers in Tasmania consider whether to switch from existing fuels to gas.

Figure 2.4: Residential gas consumption 2004-05



Source: ABARE, Australian Energy Consumption and Production 1974-75 to 2004-05, Table F
Note: The New South Wales estimates include consumption in the Australian Capital Territory.

2.1.1. Influence of alternative fuels on the demand for gas

Like other fuels, the demand for gas over the medium term may be influenced by the price of alternative fuels. The extent of this influence will vary across industries and across locations and will largely depend on the substitutability of alternative fuels for particular end users. Where an alternative fuel can be utilised by a user, the influence of this fuel on the demand for gas will depend on the price of alternative fuels, the availability of alternative fuels, the cost of switching and the time taken to switch.

The influence of other fuels on the demand for gas has been considered on a number of occasions by the Australian Competition Tribunal, the National Competition Council and the Productivity Commission. A summary of these findings is set out below.

Australian Competition Tribunal

The Australian Competition Tribunal's first consideration of this issue occurred in 1997 when it examined the *AGL Cooper Basin Natural Gas Supply arrangements.*[5] Within this decision the Australian Competition Tribunal found that the market for natural gas at times extended at the margin to encompass alternative and complementary energy sources and in particular electricity.[6]

This issue was considered again by the Australian Competition Tribunal in 2002 when it reviewed the Minister for Industry, Science and Resources' decision to cover the Eastern Gas Pipeline.[7] The Australian Competition Tribunal concluded that the relevant market in that context was the market for natural gas and noted that there was little competition between energy sources at the time of the decision. In reaching this conclusion the Australian Competition Tribunal noted the following:

> Estimates of price elasticities are the main evidence used to argue that gas and electricity are provided in separate markets. The available evidence indicates that the price elasticity of demand for gas is low, and that gas prices have little influence on the demand for electricity (cross price elasticity). The elasticities were estimated using data which pre-dates the reforms in the gas industry so they are likely to be underestimates of the actual position today. In the future, changes in technology and the use of gas to generate electricity from 2006 onwards could be expected to lead to a more integrated energy market.[8,9]

Although the Australian Competition Tribunal concluded that in general there was limited competition between alternative energy forms in markets, it did observe that in markets where gas had not previously been available, alternative energy forms may provide more of a competitive constraint as users in these locations would need to be encouraged to invest in alternative appliances or production processes. Specifically, the Australian Competition Tribunal found:

> …. as gas has not previously been available, the ability to monopoly price would be restricted because potential users have bargaining power, the costs of conversion to enable the use of gas are significant, and EGP has committed assets which it has incentives to use. In other words, the prices of existing forms of energy will be a countervailing force on the price of gas and pipeline services. The market definition

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5 Alliance Petroleum Australia Pty Ltd & Ors; Re: Application for a review of a determination of the Australian Competition & Consumer Commission made on 27 March 1996 revoking authorisation No A90424 and granting a further authorisation (AGL Cooper Basin Natural Gas Supply arrangements) [1997] ACompT 2 (14 October 1997).

6 [1997] ACompT 2 (14 October 1997) (1997) ATPR 411-593 at pp. 44210-44211.

7 Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT 2 (4 May 2001)

8 Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT 2 (4 May 2001), paragraph 79.

9 The cross price elasticity of demand for a product (ie, gas) describes the sensitivity of demand to changes in the price of another product (ie, electricity). It is measured by the ratio of the percentage change in demand for gas divided by the percentage change in price of electricity. If a one per cent change in the price of electricity results in a greater than one per cent change in the demand for gas, the cross price elasticity of demand for gas, which will be greater than one, is said to be elastic, ie, demand for gas is relatively responsive to electricity price changes. On the other hand, if a one per cent change in electricity prices results in a change in demand for gas of less than one per cent, the elasticity of demand for gas, which will be less than one, is said to be inelastic, ie, demand for gas is relatively unresponsive to electricity price changes.

> adopted by the Tribunal does not include other forms of energy at the current time where gas is well entrenched, but could include it in the long term when gas is used to generate electricity. In the regional markets, other forms of energy warrant consideration because gas is being offered as an alternative to existing forms of energy.[10]

National Competition Council

The National Competition Council considered the extent to which electricity may be viewed as a substitute for gas in its final recommendations made in relation to the Eastern Gas Pipeline application for coverage[11] and the Moomba to Sydney Pipeline application for the revocation of coverage.[12]

In its consideration of the Eastern Gas Pipeline application for coverage, the National Competition Council referred to a cross-elasticity study undertaken for the Australian Gas Association by ABARE in 1996 which utilised data over the period 1973-74 to 1993-94.[13] According to this study, a one percentage change in the price of gas resulted in:

- a 0.15 percentage increase in demand for electricity in the residential sector;
- a -0.03 percentage increase in the demand for electricity in the commercial sector; and
- no change in the demand for electricity in the industrial sector.

Based on these results the National Competition Council concluded that the very low cross-elasticity of demand supported the conclusion that gas and electricity remain in two separate markets[14]

Within the Moomba to Sydney Pipeline Final Recommendation the National Competition Council similarly concluded that the relevant product market was the market for natural gas and did not extend to other fuels.[15]

Productivity Commission

The Productivity Commission's consideration of the influence of alternative fuels on the residential demand for gas was set out in its review of the Gas Code.[16] Within this review, the Productivity Commission concluded that electricity was an important competitor to natural gas in the residential segment of the market and noted that the competitive pressure

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10 Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT 2 (4 May 2001), paragraph 129.

11 National Competition Council, Final Recommendation – Application for Coverage of Eastern Gas Pipeline, June 2000.

12 National Competition Council, Final Recommendation Moomba to Sydney Pipeline System – Revocation Applications Under the National Gas Code, 2002.

13 Australian Gas Association, AGA Research Paper No. 3 – Price Elasticities of Australian Energy Demand, 1996.

14 National Competition Council, Final Recommendation – Application for Coverage of Eastern Gas Pipeline, June 2000, pg. 62.

15 National Competition Council, Final Recommendation Moomba to Sydney Pipeline System – Revocation Applications Under the National Gas Code, 2002, pp. 105-106.

16 Productivity Commission, Review of the Gas Access Regime, August 2004.

exerted by electricity was ongoing.[17] In reaching this conclusion the Productivity Commission noted:

> …although individual customers might be locked into using a natural gas appliance for around 10-15 years, around 7 per cent of consumers change appliances every year.[18]

The Productivity Commission further observed that the competitive pressure exerted by alternative fuels will be particularly significant in those locations where gas has not previously been marketed and cited Tasmania as an example of such a market.[19]

2.2. Forecast growth in consumption[20]

In December 2006 ABARE released its latest projections for energy consumption in Australia to 2029-30.[21] According to these projections natural gas consumption in eastern Australia will increase by 61 per cent over the period 2004-05 to 2029-30 from 694 PJ to 1,116 PJ. The projected growth of consumption across each state varies considerably with South Australia's demand projected to increase by just 7 per cent while demand in Queensland and Tasmania is projected to increase by 142 per cent and 108 per cent respectively. Consumption in New South Wales and Victoria is expected to grow at more moderate rates of 52 per cent and 53 per cent respectively.

Figure 2.5 sets out the projections for each state over the period. By the end of the projection period Victoria is expected to remain the largest consumer of gas while Queensland will overtake New South Wales as the second largest consumer.

ABARE's projections for gas demand and supply also assume that by 2012-13 demand in eastern Australia will exceed local supply by 56 PJ and thus an external source will be required at this time to meet the projected gap.[22] ABARE has projected that this gap will widen over the remainder of the forecast period such that by 2029-30 an external source will be required to deliver between 190 PJ to 377 PJ.

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17 Productivity Commission, Review of the Gas Access Regime, August 2004, pg. 48.

18 Productivity Commission, Review of the Gas Access Regime, August 2004, pg. 48.

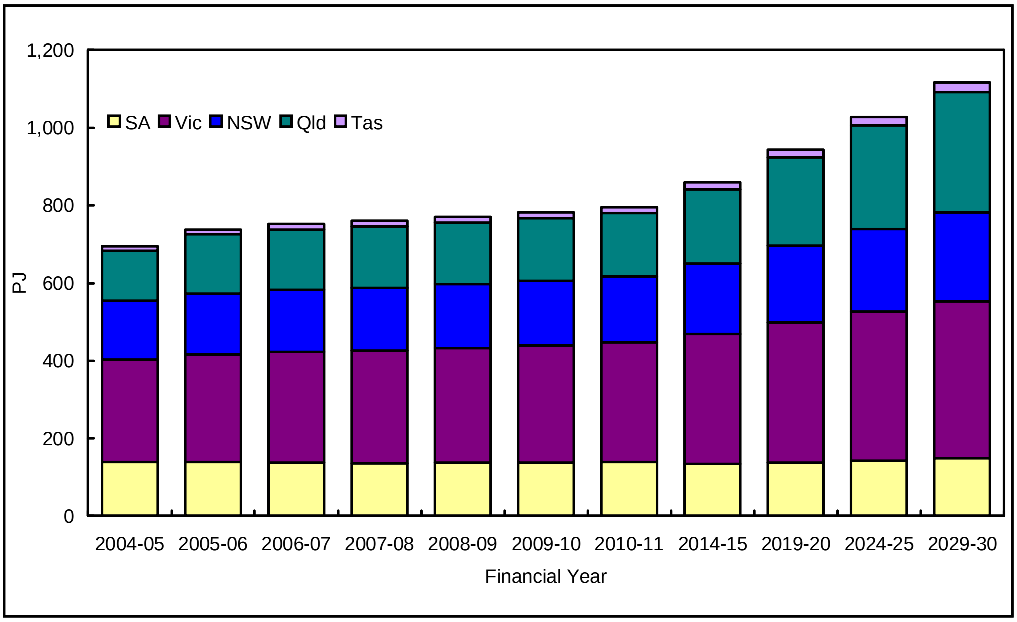
19 Productivity Commission, Review of the Gas Access Regime, August 2004, pg. 49.

20 The information contained in this section has primarily been sourced from ABARE, National and State Projections to 2029-30, December 2006.

21 ABARE, National and State Projections to 2029-30, December 2006, Tables E2a, b and c.

22 ABARE, National and State Projections to 2029-30, December 2006, pg. 42.

Figure 2.5: ABARE gas consumption projections 2004-05 to 2029-30



Source: ABARE, National and State Projections to 2029-30 Tables E2a and b
Note: The New South Wales estimates include consumption in the Australian Capital Territory.

3. Upstream gas production

3.1. Overview of the sources of supply in eastern Australia

The sources of conventional natural gas in eastern Australian include the Cooper/Eromanga Basin (onshore), the Otway Basin (offshore), the Bass Basin (offshore) and the Gippsland Basin (offshore). Coal seam methane fields have also been discovered in Camden, the Hunter Valley, the Bowen Basin, the Surat Basin, the Adavale Basin and the Clarence-Moreton Basin.[23]

Within each of these basins there are a number of gas fields currently producing conventional natural gas or coal seam methane including:

§ Cooper/Eromanga Basin – there are a number of fields in South Australia (jointly referred to as Moomba) and South West Queensland (jointly referred to as Ballera) currently producing conventional natural gas;

§ Gippsland Basin - the fields currently producing conventional natural gas include Bass Strait and Patricia Baleen;

§ Otway Basin - the fields currently producing conventional natural gas include Minerva, Geographe/Thylacine, Casino and Katnook;

§ Bass Basin - Yolla is currently the only field producing conventional natural gas; and

§ Bowen/Surat/Clarence-Moreton basins - the fields producing conventional natural gas and coal seam methane include Fairview, Spring Gully, Peat, Mungi, Scotia, Dawson Valley, Moranbah, Roma, Denison Trough, Argyle, Lauren, Berwyndale South, Tipton West and Kogan North.

In addition to the fields that are currently producing gas there a number of other projects that are currently being developed. These projects include:

§ the Golden Beach gas project in the Gippsland Basin which is being developed by Cape Energy (Victoria). The estimated reserves for this field are 50 PJ and the estimated start up date is the second half of 2007;[24]

§ the Longtom gas project in the Gippsland Basin, which is being developed by Nexus Energy. The estimated reserves are 338 PJ and estimated start up is mid-2008; [25]

§ the Kipper gas project in the Gippsland Basin which is being developed by Exxon (Esso). The estimated reserves for this field are 663 PJ and the estimated start up date is 2009;[26]

§ the Manta and Gummy gas project in the Gippsland Basin which is being developed by Beach Petroleum and Anzon. A conditional gas supply contract has been entered into by these parties to supply Alinta 225 PJ over a fifteen year period. Supply under this contract is expected to commence in 2009;[27] and

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23 ABARE, Eastern Australia's Gas Supply and Demand Balance, APPEA Journal 2003, pg. 141.

24 Cape Energy website, http://www.cape-energy.com/projects_goldenbeach.asp

25 Santos Media Release, Santos finalises Longtom contract, 26 April 2007.

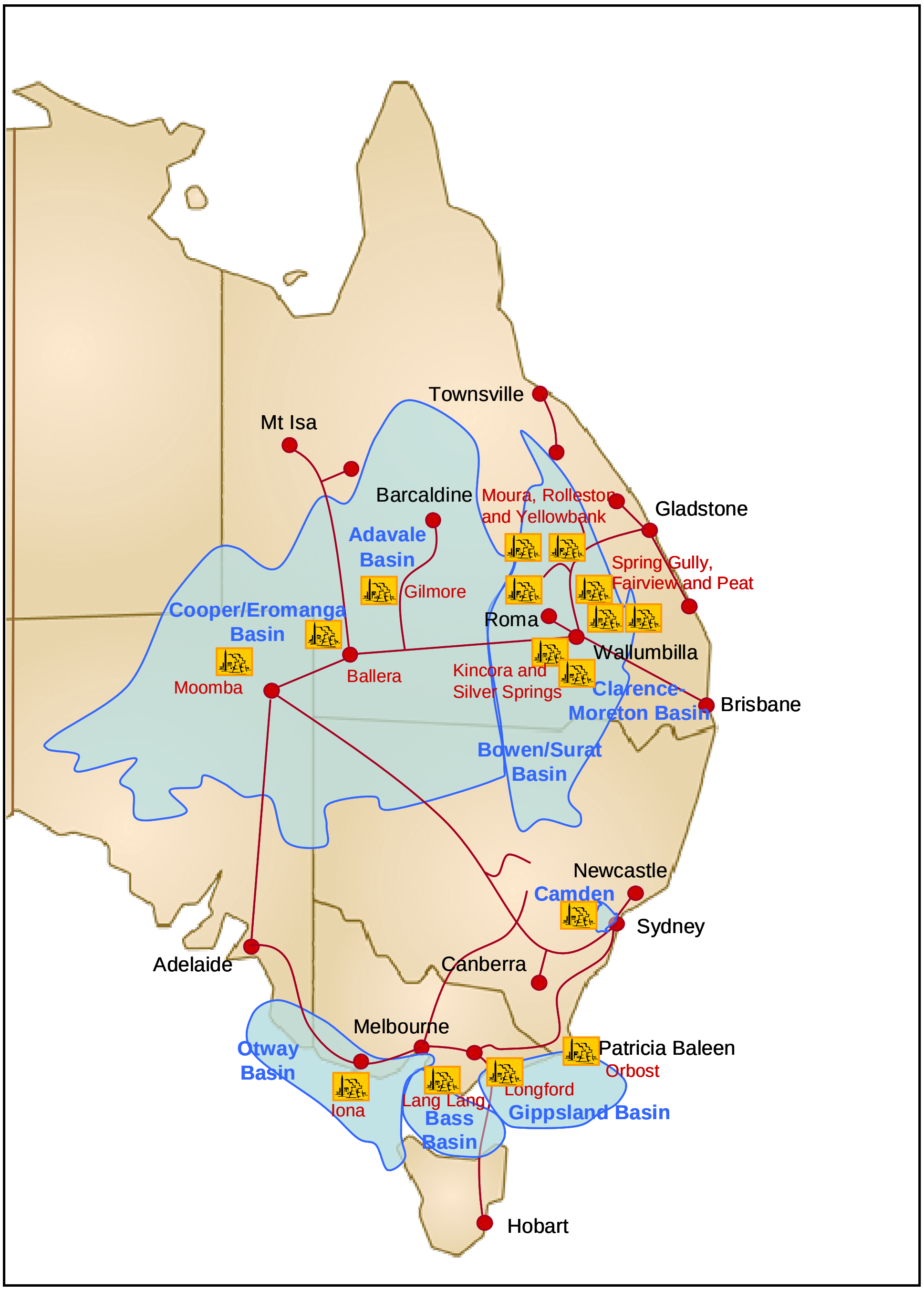
26 Department of Primary Industry, PESA News, June/July 2006, pg. 9.

27 Beach Petroleum, Manta Gummy (BMG) Gas sales agreement with Alinta Limited, 19 March 2007.

- the Henry gas project in the Otway Basin, which is being developed by AWE and Santos. The estimated reserves for this field are 160 PJ and the estimated start up date is first quarter 2009.[28]

Conventional natural gas and coal seam methane production facilities are currently located at Moomba, Ballera, Longford, Orbost, Iona, Port Campbell, Lang Lang, Gilmore, Moura, Rolleston, Yellowbank, Peat, Silver Springs, Kincora, Spring Gully, Camden and Fairview.

Figure 3.1: Location of gas basins, production facilities and pipelines in eastern Australia



28 AWE, AWE accelerates search for gas in southeast Australia, 5 March 2007.

3.2. Physical and economic characteristics

Before discussing the ownership interests in each of these conventional natural gas and coal seam methane basins and fields it is helpful to understand the basic physical and economic attributes of conventional natural gas and coal seam methane, which influence the economic viability of gas field developments and in turn:

- the ownership structures that have emerged in this segment of the gas supply chain; and
- the price producers within a particular gas field will be willing to accept for its gas.

The upstream segment of the gas supply chain encompasses both the exploration and production phases. The exploration phase for both conventional natural gas and coal seam methane is characterised by sunk costs and a relatively low probability of success.[29] The costs incurred during this phase arise from the surveying and drilling activities that are carried out to identify the presence of resources and to estimate the size of reserves where resources have been identified. Given the cost and risk characteristics of this phase, the exploration phase tends to be undertaken through joint venture arrangements, which enable both the risks and costs to be shared across the consortia.[30] Where the exploration is successful the joint venture parties may either proceed to the production phase or sell their interest to another party.

The production phase is also characterised by sunk costs and ongoing fixed costs reflecting the costs of proving up gas reserves and installing: the extraction technology; the infrastructure required to transport the gas to the processing facilities and on to the transmission pipeline; and, where relevant, processing facilities. Given the different physical characteristics of coal seam methane and conventional natural gas, the magnitude of these sunk and fixed costs may differ across these two alternative forms of gas (see section 3.2.1 and 3.2.2).

The cost characteristics of both the exploration and production phases have the potential to act as a barrier to the entry of new explorers and producers. This issue was recently considered by the ACCC in the context of Santos' proposed acquisition of QGC. In summary the ACCC found that:

- gas explorers and small new producers face significant impediments to achieve the scale necessary to enter the market for the production and supply of wholesale gas;
- there did not appear to be significant barriers for acquiring land tenements or licenses for initial exploration and test wells although geographic considerations were a significant factor for determining the success of the exploration; and
- there were high barriers to entry for junior producers seeking to become a credible alternative in the production and supply of wholesale gas directly to customers. According to the market inquiries undertaken by the ACCC, customers expressed the view that there was a preference for purchasing gas from a reliable supplier that "has

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[29] Industry Commission, Study into the Australian Gas Industry and Markets, 6 March 1995, pg. 38.

[30] Productivity Commission, Review of the Gas Access Regime, August 2004, pg. 5.

sufficient proven gas reserves, an ability to supply large volumes of gas and a track record of an ability to provide continuity of gas supply".[31]

3.2.1. Conventional natural gas

To be economically viable the development of a conventional natural gas field requires the expected reserves, demand and price to be of sufficient size to underpin:

- the large sunk costs associated with the investment in extraction technologies, the construction of production facilities and the development of pipelines to transport the gas to end markets;[32] and
- the high on going fixed costs associated with maintaining the production capacity required to supply gas on the terms required by buyers.[33]

The magnitude of both the sunk costs and the ongoing fixed costs differs across onshore and offshore projects and may change over time depending on the availability of the inputs required to extract the gas (ie, labour, drilling machinery and platforms).

If the expected revenue from a development is lower than the expected costs then the field may be left undeveloped until demand and supply conditions improve (ie, gas prices increase or the costs of extraction and production fall), such that the field becomes economically viable.

If the development of a conventional natural gas field is viewed as being economically viable then the total costs to develop the field will directly influence both the price a producer will be willing to accept, and the quantities it will be required to sell at those prices. The magnitude of these costs also exposes producers to some financial risk and thus there has been a tendency for producers to enter into long term foundation contracts to ameliorate some of the risks faced in the early years of the project's life. For example, the development of the now delayed Papua New Guinea project was underwritten by 10 to 20 year foundation contracts[34] while the development of the Cooper/Eromanga basin and the Moomba to Sydney Pipeline were underwritten by a 30 year gas supply contract.[35]

The prevalence of high sunk costs, large fixed costs and the small number of fields in Australia means that the supply of natural gas has become concentrated in the hands of a small number of producers which predominantly operate through joint venture structures and jointly market their gas.[36]

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31 ACCC, Santos Limited – proposed acquisition of Queensland Gas Company Limited, 7 March 2007, pg. 12.

32 Industry Commission, Study into the Australian Gas Industry and Markets, 6 March 1995, pg. 15.

33 Industry Commission, Study into the Australian Gas Industry and Markets, 6 March 1995, pp. 46-49.

34 AGL Media Release, AGL Commits to PNG Gas, 5 July 2005.

35 National Competition Council, Final Recommendation Moomba to Sydney Pipeline System – Revocation Applications Under the National Gas Code, 2002, pg. 38.

36 ABARE, Energy in Australia 2006, 2007, pg. 37 and Productivity Commission, Review of the Gas Access Regime, 2004, pg. 5.

3.2.2. Coal seam methane

Differences in the physical attributes of coal seam methane deposits relative to conventional natural gas mean that the costs of extracting and producing coal seam methane may differ from those incurred in the development of a conventional natural gas field. Consequently the economic viability of a coal seam methane development may vary markedly from a conventional natural gas development.

The principal differences in physical characteristics include:[37]

- the closer proximity of coal seam methane deposits to the surface relative to conventional natural gas (approximately 500 metres for coal seam methane versus 2,000-3,000 metres for conventional natural gas) which reduces unit production costs relative to conventional natural gas;
- the pressure at which coal seam methane is produced and the daily output of a coal seam methane well are substantially lower than conventional natural gas (300-500 kPa versus 7,000-15,000 kPa and 0.25-0.5 TJ/day versus 10-20 TJ/day). Given these attributes a coal seam methane development will require more wells and more extensive gas gathering and compression systems to be installed to extract equivalent quantities to those that would be extracted from a conventional natural gas field development; and
- the higher methane content of coal seam methane and the lower levels of impurities relative to conventional natural gas (95 per cent versus 90 per cent) which reduces the complexity of the processing required by coal seam methane relative to conventional natural gas.

Given these physical attributes, coal seam methane fields have tended to be developed on an incremental basis and as a consequence the up front capital investment required for a coal seam methane development will generally be lower than that required to bring a conventional natural gas development on stream.[38]

The lower level of sunk costs associated with coal seam methane extraction also means that:

- the development may be viable even where the reserves are relatively small;
- a larger number of small scale producers can be involved in the development of these discoveries; and
- producers of coal seam methane may be willing to accept a lower price than their conventional natural gas counterparts.

The coal seam methane projects that have been developed to date have tended to be located relatively close to end markets. This has led to these projects being competitive with conventional natural gas in Queensland and New South Wales, which tend to be transported long distances to end markets.

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37 M. Kimber and A. Moran, Coal Seam Methane in the 21st Century, December 2004.

38 M. Kimber and A. Moran, Coal Seam Methane in the 21st Century, December 2004, pg. 8.

One characteristic that can detract from the attractiveness of coal seam methane is that there are limits on the extent to which producers can increase or decrease production (flow rates). This characteristic means that producers of coal seam methane can offer a buyer very little daily contract quantity flexibility, which can reduce the value of this source of supply for a buyer with peaky demand requirements.[39] This characteristic of coal seam methane may be less important where the field is relatively large, and users have offsetting demand profiles such that the overall load profile for demand is flat. The development of storage facilities may also provide a means for producers of coal seam methane to meet peak demand requirements, however, the scope for this may be limited.[40]

Another factor that affects the attractiveness of coal seam methane in some areas is that in the early development stages there may be some uncertainty surrounding the ability of those fields to extract coal seam methane and to deliver the contracted quantities. The Sydney Gas Company's Camden project provides an example of the uncertainty that surrounds the deliverability of a coal seam methane project particularly at the outset of the project. In 1999 AGL entered into an agreement with the Sydney Gas Company to purchase 4.5 PJ per annum. These contracted quantities were further supplemented in December 2002 by an additional agreement in which AGL agreed to purchase a further 10 PJ per annum taking the total contracted commitment to 14.5 PJ per annum.[41] Although AGL has had an agreement to purchase 4.5 PJ per annum for over seven years production levels only reached 4 PJ in 2006,[42] which is still significantly below the 14.5 PJ per annum contracted quantities.

3.3. Market structure

The table on the following pages provides a summary of the pertinent features of each of the gas basins currently producing gas (or due to commence production in the next six months) to supply end-users located in eastern Australia. Included within this table are the current joint venture arrangements prevailing in each field, annual production estimates, [43] and the latest available estimates of proved and probable reserve levels.

The terms proved and probable reserves (jointly referred to as 2P reserves) are defined as the volumes of gas reserves which, under current economic and operating conditions, are commercially recoverable with a probability of at least 50 per cent.

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39 According to ABARE, limitations on the ability to increase coal seam methane production flow rates, however, mean that the terms of supply will be less flexible than that available from the natural gas basins. ABARE, Eastern Australia's Gas Supply and Demand Balance, APPEA Journal, 2003, pg. 141.

40 ABARE, Eastern Australia's Gas Supply and Demand Balance, APPEA Journal 2003, pg. 141.

41 AGL, Media Release - AGL and Sydney Gas Company Sign Second Gas Supply Agreement, 4 December 2002.

42 Sydney Gas, 2006 Annual Report, pg. 8.

43 It is important to note that some conventional natural gas production and reserve estimates may include ethane estimates.

Table 3.1: Upstream production

Basin	Field	Location	Gas Type	Ownership Structure	Date Production Commenced	2P Reserve Estimates	Estimated Annual Production	Sources
Bowen/Surat/Clarence - Moreton	Fairview	QLD	CSM	79.5% Santos, 20.5% Origin	1998	1565 PJ	13.9 PJ	2006 production (Origin production reports and APPEA data), end 2006 reserves (Q4 2006 Core Collaborative), current equity (Santos site)
	Spring Gully	QLD	CSM	~ 97% Origin, ~3% minor interests (incl ~1% Santos)	2005	739 PJ	11.6 PJ	2006 production (Origin production updates and APPEA data), equity and 2005 reserves (Origin presentation, Q4 2006 Core Collaborative)
	Peat	QLD	CSM	Origin	2000	31 PJ	4 PJ	current production and equity (Origin website), end 2005 reserves (Geoscience Australia)
	Mungi	QLD	CSM	25% Molopo, 25% Helm Energy Australia, 25.5% Anglo Coal (Australia) and 24.5% Mitsui Moura	2003	25 PJ	1.1 PJ	2005 production and reserves (GA), current equity (Molopo website)
	Scotia	QLD	CSM	Santos	2002	150 PJ	8.4 PJ	2005 Production (incl ethane) and current equity (Santos website), end 2005 reserves (Core Collaborative)
	Dawson Valley Coal Mine	QLD	CSM	51% Anglo Coal, 49% Mitsui Moura Investment	1996	54 PJ	9 PJ	reserves late 2005 (Geoscience Australia), current equity and production rate (Anglo Coal website)
	Moranbah	QLD	CSM	50% Arrow Energy, 50% AGL	2004	382 PJ	16 PJ	2006 production and current equity (Arrow website), reserves late 2005 (Geoscience Australia)
	Roma	QLD	conventional natural gas	varies across blocks: Roma 100% Santos, Waldegrave 53.75% Santos and 46.25% Origin, and various others	1961	n.a.	n.a.	current equity (Santos website)
	Denison Trough	QLD	conventional natural gas	50% Origin, 50% Santos	1989	111 PJ	11.95 PJ	2006 production (APPEA), current equity (Santos website), reserves end 2005 (Core Collaborative)
	Argyle	QLD	CSM	59.375% QGC (AGL holds 27.5% interest), 40.625% Origin	expected March 2007	181.4 PJ	n.a.	reserves and equity end 2006 (Q4 2006 Core Collaborative)
	Lauren	QLD	CSM	59.375% QGC (AGL holds 27.5% interest), 40.625% Origin	expected mid-2007	286.7 PJ	n.a.	reserves and equity end 2006 (Q4 2006 Core Collaborative)
	Berwyndale South	QLD	CSM	90% QGC (AGL holds 27.5% interest) but may increase to 100% if the Sentient Global Resources consolidation proceeds	2006	268.8 PJ	13 PJ	2006 production (2006 half-year report), reserves end 2006 (Q4 2006 Core Collaborative), current equity (QGC half-year report and website)
	Tipton West	QLD	CSM	60% Arrow Energy, 40% Beach	February 2007	174 PJ	n.a.	Arrow website
	Kogan North	QLD	CSM	50% Arrow Energy, 50% CS Energy	early 2006	83 PJ	1.2 PJ	12 months to end March 07 production (Arrow Energy quarterly report 31/03/07), remaining Arrow website

Basin	Field	Location	Gas Type	Ownership Structure	Date Production Commenced	2P Reserve Estimates	Estimated Annual Production	Sources
Sydney	Camden	NSW	CSM	50% AGL, 50% Sydney Gas	2001	83 PJ	4 PJ	2006 SGL Annual report
Cooper / Eromanga	South Australian Cooper Basin	SA	conventional natural gas	66.6% Santos, 20.2% Beach, 13.2% Origin	1969	1287 PJ	173.3 PJ	2006 production (APPEA), equity and reserves (Q4 2006 Core Collaborative)
	Ballera	QLD	conventional natural gas	60.0625% Santos, 23.2% Beach, 16.7375% Origin	1994			
Gippsland	Patricia Baleen	VIC	conventional natural gas	Santos	2003	68.1 PJ	5.98 PJ	2006 production (APPEA), end 2006 reserves (DPI 05/07), equity (Santos website)
	Bass Strait	VIC	conventional natural gas	50% BHP Billiton, 50% Exxon (Esso)	1969	4,411.6 PJ	236 PJ	FY 2006 production (BHP Billiton Petroleum Review 06), reserves and equity end 2006 (DPI 05/07)
Otway	Katnook	SA	conventional natural gas	71.7143% Origin (but may increase if it is able to accquire Omega's), 24.2857% Omega, 4 % other minority interests	1988	n.a.	6.01 PJ	2006 production (APPEA) Note: reserves have been written down in this basin (Origin AR 2005)
	Minerva	VIC	conventional natural gas	90% BHP Billiton, 10% Santos	end 2004	316 PJ	35.18 PJ	FY 2006 production (BHP Billiton 06), reserves and equity (DPI 07/05)
	Casino	VIC	conventional natural gas	50% Santos, 25% Peedamullah Petroleum, 25% Mittwell Energy Resources	Feb-06	285 PJ	14.4 PJ	2006 production (APPEA), reserves and equity (PESA 07/06)
	Geographe and Thylacine	VIC	conventional natural gas	51.55% Woodside, 30.75% Origin, 12.7% Benaris International, 5% CalEnergy Gas	Feb-07	885 PJ	n.a.	equity (project website), reserves (PESA 07/06)
Bass	Yolla	TAS	conventional natural gas	32.5% Origin Energy, 5% Origin Energy Northwest, 30% AWE Petroleum, 20% CalEnergy Gas, 12.5% Wandoo Petroleum Ltd	Jun-06	324 PJ	7.5 PJ	2006 production (APPEA), reserves and equity (PESA 07/06)

3.3.1. Observations

Drawing on the information contained in Table 3.1 a number of observations can be made in relation to the relative size of fields, market participants, the increased prominence of coal seam methane and the interests held by some of the more prominent gas retailers.

Relative size of fields

Drawing on the production and reserve estimates contained in Table 3.1 the following two charts have been developed comparing the size of each field. Interestingly, the more mature fields in the Gippsland Basin and the Cooper/Eromanga Basin are still the largest basins both in terms of production and reserve estimates relative to some of the newly developed fields.

Figure 3.2: Estimated annual production by gas field

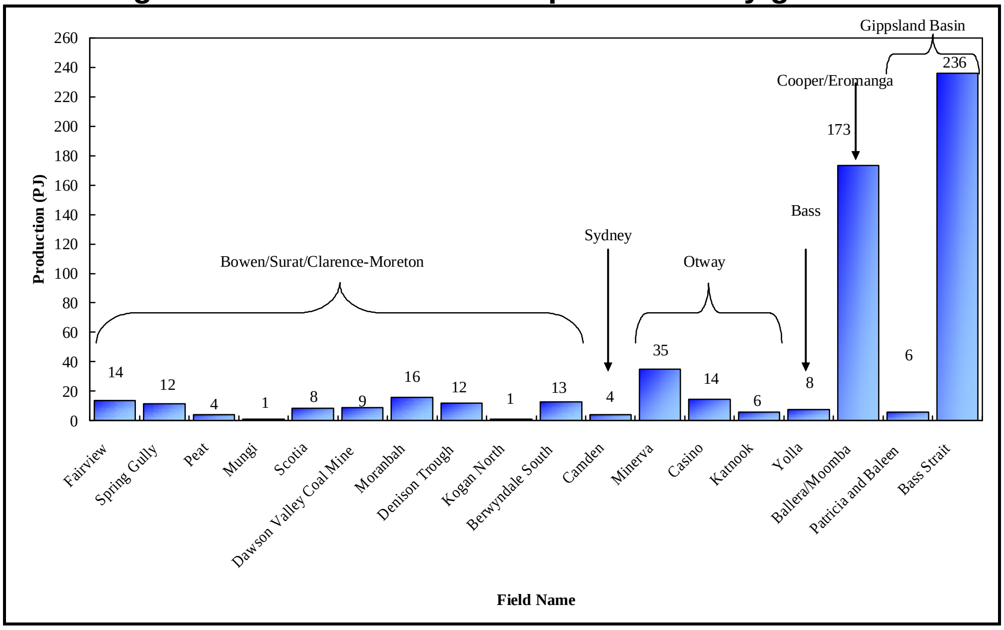
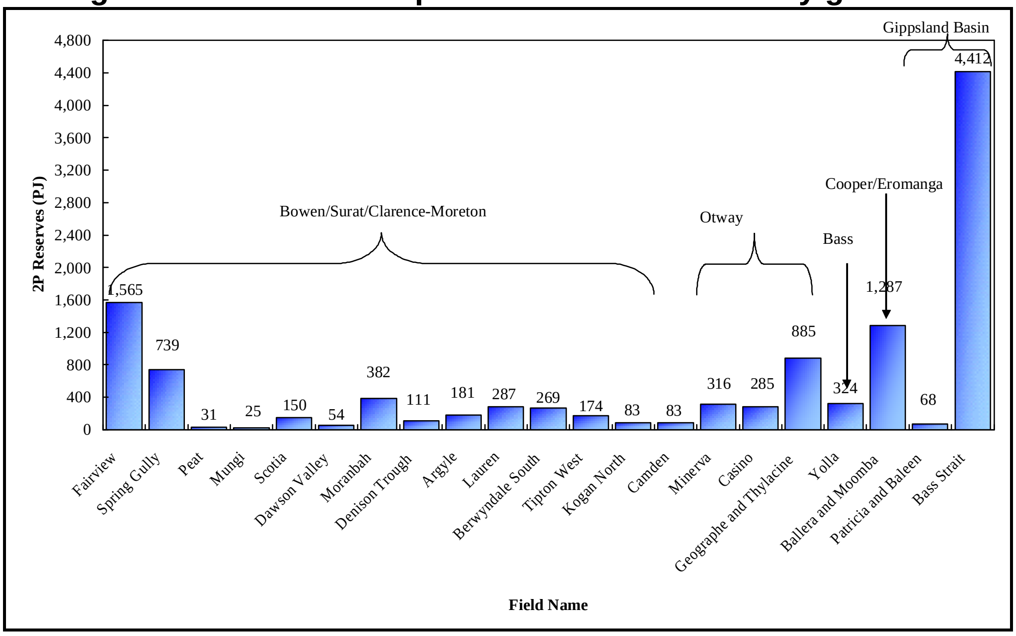


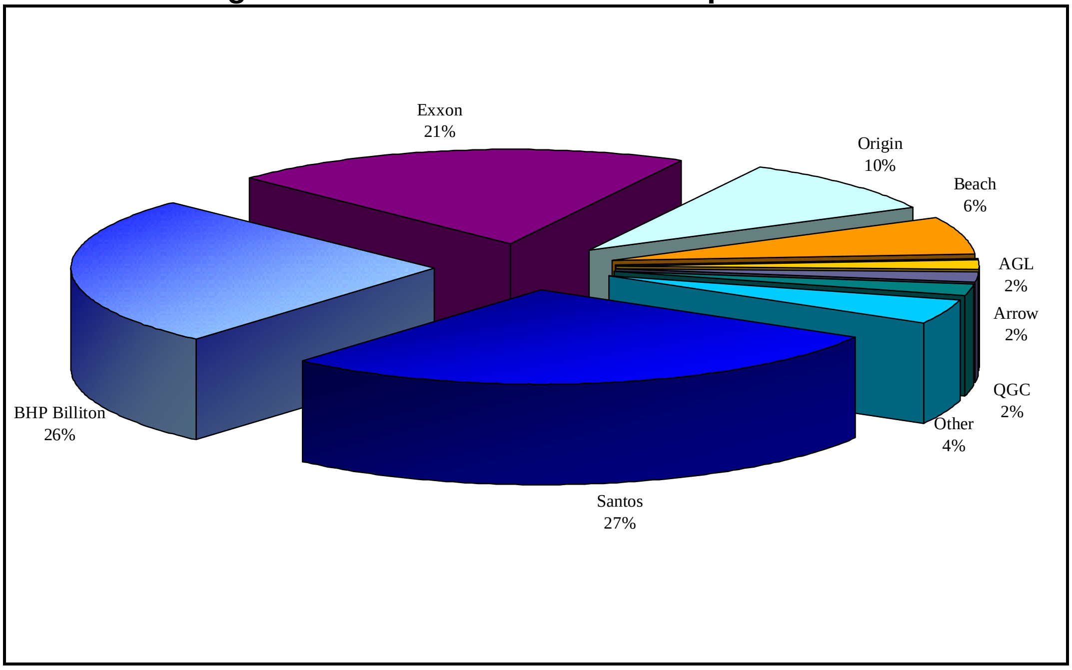
Figure 3.3: Proven and probable reserve levels by gas field



Market participants

There are currently 24 identified entities with equity interests in the various gas fields in eastern Australia. Notwithstanding this apparent diversity of interests, control of the more substantially sized gas fields (ie, Gippsland Basin and Cooper/Eromanga Basin) is concentrated in the hands of established producers, Santos, Origin, BHP Billiton and Exxon (Esso). These four entities also have interests in a number of other fields and accounted for 84 per cent of the estimated production in 2006 once joint venture interests in all fields were taken into account (see Table 3.1).[44]

Figure 3.4: Interests in estimated production



If proven and probable reserve estimates are indicative of future production, then the concentration in this segment of the gas supply chain will diminish somewhat over time assuming there is no further consolidation in this segment of the supply chain. Using the reserve estimates presented in Table 3.1 and the joint venture shares in each field, the interests Santos, Origin, BHP Billiton and Exxon (Esso) hold in each field currently accounts for 75 per cent of proven and probable reserve estimates.[45] A further 18 per cent of the proven and probable reserve estimates are accounted for by Woodside, Arrow, Beach, QGC and AGL with the latter four of these parties' interests stemming from coal seam methane. Figure 3.3 illustrates the relative shares each of these entities has in the proven and probable reserves.

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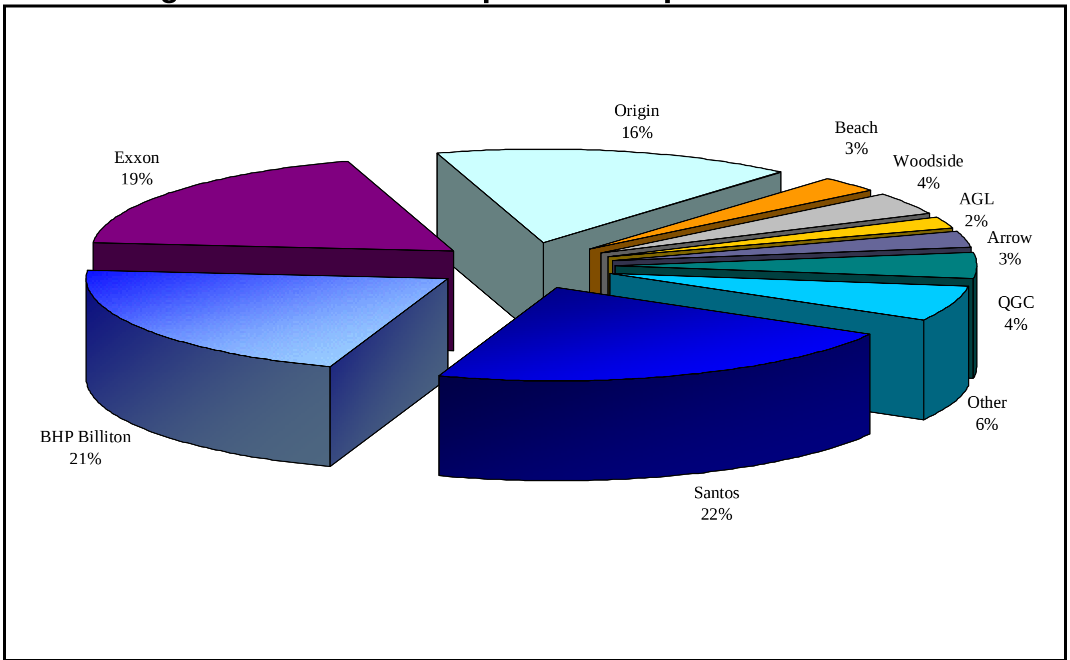
44 These estimates are lower than those previously reported by ABARE in *Australian Gas Markets Moving Towards Maturity* (December 2003, pg. 34). According to the estimates contained in this report 99.5 per cent of the market in 2001 was controlled by these four entities and by 2010 ABARE expected that 93 per cent of the market would be controlled by Santos, Origin, BHP Billiton and Exxon (Esso). It would appear that difference between ABARE's estimates and those presented above stems from the fact that ABARE attributed the production from each field to the field operator rather than separately taking into account the joint venture interests (ie, all of the Cooper/Eromanga Basin production would be attributed to Santos).

45 Sydney Gas, Fact Sheet – AGL and Sydney Gas Joint venture, 14 September 2005.

Figure 3.5: Interests in proven and probable reserves



Note: AGL's 27.5 per cent interest in QGC has not been included in the AGL estimate.

ABARE's recent energy projections to 2029-30[46] also contained its assumptions about projected supply from the Gippsland, Cooper/Eromanga, Otway and Other (including Adavale, Bass and Bowen) basins. According to these assumptions the Gippsland Basin will account for 34 per cent of supply by 2029-30 (down from 45 per cent in 2004-05) while the Cooper/Eromanga Basin will account for less than one per cent (down from 40 per cent in 2004-05).[47]

Figure 3.6 illustrates ABARE's production forecasts which assume:

§ production from the Gippsland Basin will peak in 2021-22 at 392 PJ and will decline thereafter;

§ production from the Cooper/Eromanga Basin will decline moderately over the period 2004-05 to 2011-12 and thereafter decline more rapidly;

§ production from the Otway Basin will fill some of the gap left by the Cooper/Eromanga Basin although the production levels in this field will decline rapidly from 2020-21; and

§ increased production of coal seam methane will also offset the decline in production from both the Cooper/Eromanga and Gippsland basins.

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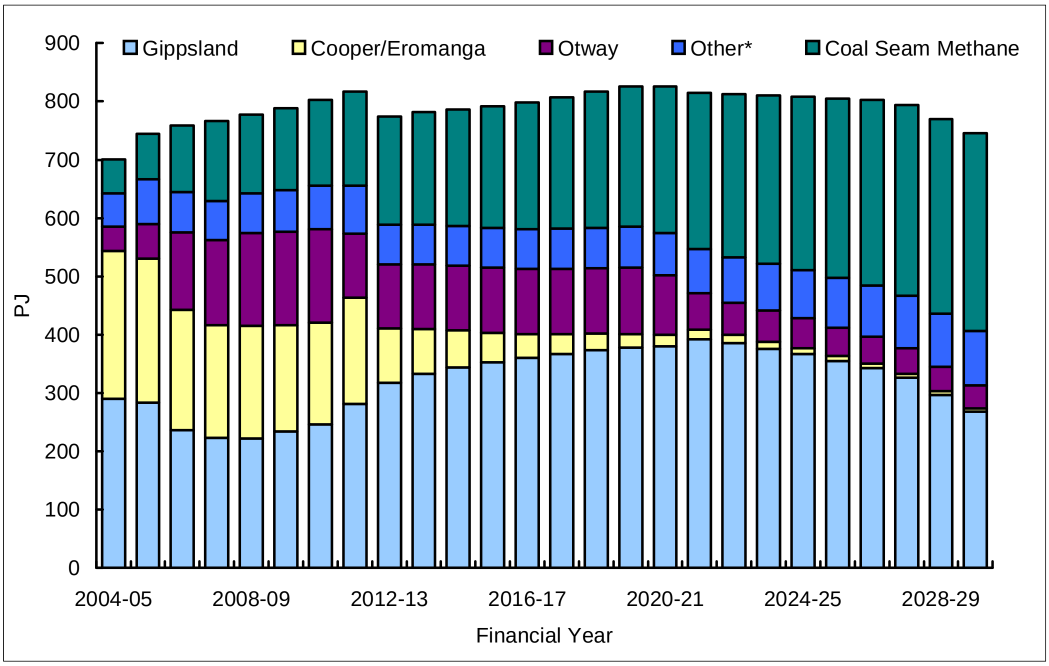
46 ABARE, Australian Energy National and State Projections to 2029-30, December 2006.

47 ABARE, Australian Energy National and State Projections to 2029-30, December 2006, Table G. Note these estimates include minimal quantities of ethane and methane.

Figure 3.6: Forecast gas production



Source: ABARE Table G.
* Other includes conventional natural gas from the Adavale, Bass and Bowen basins and ethane from the Cooper and Gippsland basins.

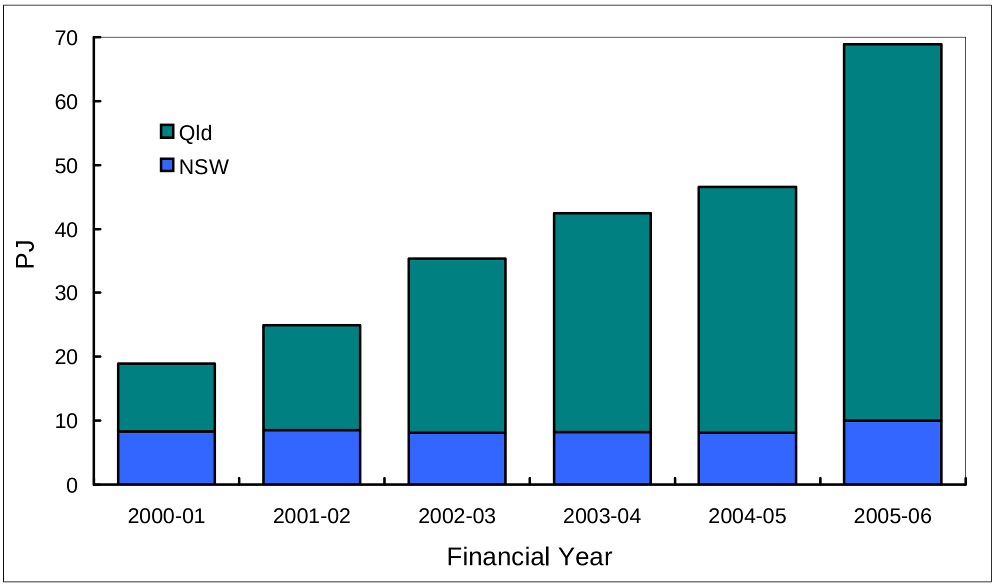
Increased prominence of coal seam methane

According to data presented in ABARE's Energy in Australia 2006 report, coal seam methane production has increased by 360 per cent over the period 2000-01 to 2005-06 from 19 PJ to 69 PJ.[48] The growth in production has been more pronounced in Queensland than New South Wales with production increasing by 460 per cent in Queensland compared to 20 per cent in New South Wales. The growth in production across the two states can be seen in Figure 3.4 below.

The prominence of coal seam methane can also be seen in the production and proven and probable estimates presented in Table 3.1. According to the information in Table 3.1, coal seam methane accounted for 14 per cent of production and accounted for 35 per cent of current proven and probable reserve estimates.

[48] ABARE, Energy in Australia 2006, March 2007, pg. 36.

Figure 3.7: Coal seam methane annual production 2000-01 to 2005-06



Source: ABARE Energy in Australia 2006, pg. 36.
Converted from Gigalitres to PJ using a factor of 0.0383

Retailer's upstream interests

Another interesting point to note from Table 3.1 is that both Origin and AGL have interests in both upstream production and retail.

While Origin has held an interest in the Cooper/Eromanga Basin for some time, it has over the last seven years acquired further interests in both the offshore developments in Victoria and the coal seam methane fields in Queensland. These interests may be viewed as placing Origin in a superior position in terms of servicing its retail customer base in both Melbourne and Adelaide and will stand it in good stead to service the Brisbane customer base it recently obtained as a result of the Sun Retail acquisition.

In a recent presentation Origin referred to its ability to procure gas for its retail operations from third party suppliers, its joint ventures and its own production and concluded that it has "significant flexibility in gas supply - and has the option to buy from third parties if gas prices are low and develop equity gas if gas prices rise".[49] Origin further noted that it has been reducing the amount of gas it purchases from third parties and increasing its purchase of equity gas.[50]

AGL's interest in upstream gas fields has occurred more recently than Origin's, commencing with the development of a joint venture arrangement with Sydney Gas Company in 2005.[51] In 2006 AGL increased its interest in coal seam methane by entering into a joint venture arrangement with Arrow in the Moranbah field and by acquiring a 27.5 per cent interest in

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49 Equity gas is when an equity interest is held in the joint venture arrangement.

50 Origin, US Roadshow, May 2007, pg.20.

51 AGL, AGL Completes Sydney Gas Joint Venture, 15 November 2005.

QGC.[52] At the same time, AGL entered into a gas sales agreement to purchase up to 540 PJ over twenty years.[53] In a statement released at the time of this transaction, AGL Managing Director and CEO, Paul Anthony, stated:

> As well as delivering our wholesale energy portfolio further fuel diversity, price competitiveness, stability and longevity of gas supply, this transaction is also a perfect fit with our recent acquisition of Sun Gas which has 70,800 customers in south-east Queensland representing approximately 50 per cent of Queensland's mass market customer base. [54]

AGL's coal seam methane interests in both Sydney and Queensland and its associated gas supply contracts ensure that AGL has access to gas that is proximately located to its retail customer bases in both Sydney and Brisbane.

According to a presentation made to investors by AGL Managing Director and CEO, Paul Anthony, AGL is seeking to increase its equity interest in the upstream production to between 3,000 to 4,000 PJs of gas[55] and to obtain a target portfolio of 50 per cent equity gas so that it can profit from the future price appreciation.[56]

3.4. Wholesale gas supply arrangements

The wholesale supply of gas in eastern Australia is dominated by long-term, highly customised bilateral gas supply contracts entered into on an infrequent basis with a limited number of end-users. Invariably, these contracts are highly confidential. Historically there has also been a tendency for producers operating under joint venture arrangements to market their gas jointly.

Long term nature of gas supply contracts

Estimates put forth by APPEA suggest that 95 per cent of the market is supplied under long term contracts.[57] The dominance of long term contracts largely reflects the tendency of producers to underwrite the significant capital investment required at the commencement of the field's life with long term foundation contracts as can be seen in the following examples:

- the development of the now delayed Papua New Guinea project was to be underwritten by 10-20 year foundation contracts;[58]
- the 540 PJ gas supply agreement recently entered into between AGL and QGC was to enable supply over a twenty year period;[59]

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52 AGL, AGL Secures Cornerstone Investment in QGC, 5 December 2006.

53 AGL, AGL Secures Cornerstone Investment in QGC, 5 December 2006.

54 AGL, AGL Secures Cornerstone Investment in QGC, 5 December 2006.

55 AGL Energy, Strategy Update, May 2007, Slide 6.

56 AGL Energy, Strategy Update, May 2007, Slide 18

57 APPEA, Submission to the Allen Consulting Group Options for the development of the Australian wholesale gas market, 2005, pg. 2.

58 AGL Media Release, AGL Commits to PNG Gas, 5 July 2005.

59 AGL, AGL Secures Cornerstone Investment in QGC, 5 December 2006.

- the 225 PJ gas supply agreement recently entered into between Beach Petroleum and Alinta for supply from the Manta and Gummy fields is to be supplied over a fifteen year period;[60]
- Woodside's share of the Geographe and Thylacine development has been sold to TRUenergy over 10 years;[61]
- the 425 PJ gas supply agreement entered into between Santos and TRUenergy for supply from the Casino fields is to be supplied over a 12 year period with an option to extend 3 years;[62] and
- the development of the Cooper/Eromanga basin and the Moomba to Sydney Pipeline were underwritten by a 30 year contract.[63]

Joint marketing of gas

Joint venture parties operating in a basin or a field have to date predominantly sold their gas through joint marketing arrangements.[64] While this practice continues (as exemplified by the joint marketing arrangements that were put in place for the sale of gas from Papua New Guinea[65]) there have recently been some instances where the joint venture parties operating in newly developed fields have separately marketed their share of the gas. For example, Santos' interest in the Casino fields has been separately marketed as was Woodside's interest in the Geographe/Thylacine field.[66]

Highly customised nature of gas supply contracts

The terms and conditions under which gas is supplied tend to be highly customised. Nevertheless, the principal terms and conditions specified in these contracts generally include:[67]

- The firmness of the supply commitment. Gas is generally supplied under either a firm or a 'reasonable endeavours' basis. In this context 'firm' contracts require producers to supply the specified quantity of gas to each buyer, unless they are excused from doing so under the terms of the contract. In contrast, 'as available' and 'reasonable endeavours' contracts only require the producer to supply the required quantity to a buyer if it is able to do so, taking into account its firm commitments to other buyers, available reserves and its ability to produce and deliver the gas;

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60 Beach Petroleum, Manta Gummy (BMG) Gas sales agreement with Alinta Limited, 19 March 2007.

61 TRUenergy, TXU and Woodside sign gas deal, 5 August 2002.

62 http://www.santos.com/Content.aspx?p=207

63 National Competition Council, Final Recommendation Moomba to Sydney Pipeline System – Revocation Applications Under the National Gas Code, 2002, pg. 38.

64 To jointly market gas joint venture parties must obtain authorisation from the Australian Competition and Consumer Commission.

65 ACCC, PNG Gas Joint Venture Project - Authorisation A40081, May 2006.

66 TRUenergy, TXU and Woodside sign gas deal, 5 August 2002.

67 Information regarding the principal terms and conditions of supply has been obtained from the Alliance Petroleum Australia Pty Ltd & Ors; Re: Application for a review of a determination of the Australian Competition & Consumer Commission made on 27 March 1996 revoking authorisation No A90424 and granting a further authorisation (AGL Cooper Basin Natural Gas Supply arrangements) [1997] ACompT 2 (14 October 1997).

- The annual contract quantities that are set at the outset of the contract and may only be varied if there are specific annual contract variation provisions specified in the contract;
- The take or pay requirements that specify the minimum proportion of the annual contract quantities that must be paid for in any year. In some contracts the buyer is able to 'bank' any gas for which it has been required to pay but has not taken delivery, and to take that gas in future years;
- The maximum daily quantities that are either defined explicitly in the contract or calculated by reference to a defined 'swing factor'.[68] The maximum daily quantity contract provisions enable a buyer to vary their daily demand over the year by taking more than the average daily contracted quantity on any one day subject to the cap imposed by the annual contract quantities being met. These provisions therefore accord the buyer with some flexibility to manage its daily gas supply requirements over the year (see section 6.2.1). Under some contracts a buyer is able to take the maximum daily quantities on any day of the year while under other contracts this ability is restricted to certain times during the year; and
- The price escalation and price review clauses. Although many of the terms and conditions under which gas is sold are fixed over the life of the agreement, contract prices are typically set for a defined period of time, with provision for periodic reviews (ie, every three to five years). Provision is also generally made for the price to escalate on an annual basis between price reviews in accordance with a pre-defined escalation mechanism. Price escalation mechanisms are typically tied to movements in inflation although there are instances where the price has been linked to the price of other fuels and/or the price of a buyer's end product.

The price agreed within these highly customised contracts reflect:

- the values and costs the parties attribute to the terms and conditions of supply;
- the specific demand and supply circumstances faced by the buyer and the producer at their respective locations; and
- the perceptions held about the future demand and supply conditions at the time the price was agreed.

Box 3.1 provides an example of the manner in which the volume related contract provisions operate.

[68] The term 'swing factor' is sometimes referred to as the 'load factor'. The formula used to measure load factor varies across market participants with some measuring load factor as the ratio of maximum daily quantity to average daily quantity and others measuring it as the ratio of average daily quantity to maximum daily quantity. Any reference to swing factor in this report refers to the ratio of maximum daily quantity to average daily quantity.

Box 3.1: Contractual provisions

In this example it is assumed that the contract specifies annual contract quantities of 36.55 PJ pa, a take or pay requirement of 90 per cent and a maximum daily quantity of 120 TJ/day.

Under the terms of this contract:

- the average daily quantity for this contract is 100 TJ (ie, 36.55 PJ ÷ 365 days);
- the quantity of gas that the buyer will at a minimum have to pay is 32.9 PJ pa (ie, 90%× 36.55 PJ); and
- the swing factor is 120 per cent (maximum daily quantity ÷ average daily quantity = 120 TJ ÷ 100 TJ = 120%) and thus the buyer under this contract will be able to vary its daily consumption by up to 120 per cent on any day of the year subject to it meeting the constraint set by the annual contract quantities over the contract year.

3.4.1. Role of the spot market in Victoria[69]

In 1999 the Victorian Government adopted a unique market model for Victoria and accorded VENCorp[70] the role of independent system operator of both the physical spot market and the Victorian Principal Transmission System. As independent system operator, VENCorp balances gas supply and demand and transportation capacity on a daily basis through a centrally co-ordinated scheduling process and sets the market price. VENCorp also undertakes a number of other functions including identifying constraints on the transmission system and forecasting production, demand, demand variances and demand peaks. VENCorp also administers the Market and System Operation Rules (MSOR) and oversees the rule change process.

The overarching legislation which supports this system is the Victorian *Gas Industry Act (2001)* and the market is operated in accordance with the MSOR which have been authorised by the ACCC.

Physical spot market

The physical spot market in Victoria provides a means by which users can trade gas supply imbalances (ie, the difference between contracted gas supply quantities and actual requirements) on a daily basis. The spot market is settled as a net market such that market participants pay for the excess of actual withdrawals over actual injections, or receive payment for the excess of actual injections over actual withdrawals with the price paid or received being determined by the spot market. In accordance with the MSOR, the spot market price is capped at $800 per GJ.

On 1 February 2007 a new price setting mechanism was introduced into the Victorian market. Until this date the price was set on an ex-post basis at the end of each day when actual demand and supply were known. Under the new pricing mechanism, demand and supply are balanced at defined intervals over the day (6 am to 10 am, 10 am to 2 pm, 2 pm to 6 pm, 6 pm

69 The information contained in this box has been prepared using VENCorp, Guide to the Gas Market, VENCorp, Victorian Gas Market Stage 1 Design Functional Description, 3 April 2006 and VENCorp, Gas Scheduling Procedures Version 5.1, 1 February 2007.

70 VENCorp is non-profit organisation owned by the Victorian government. It recovers its costs through regulated fees for its statutory functions and on a fee-for-service basis for non-statutory functions.

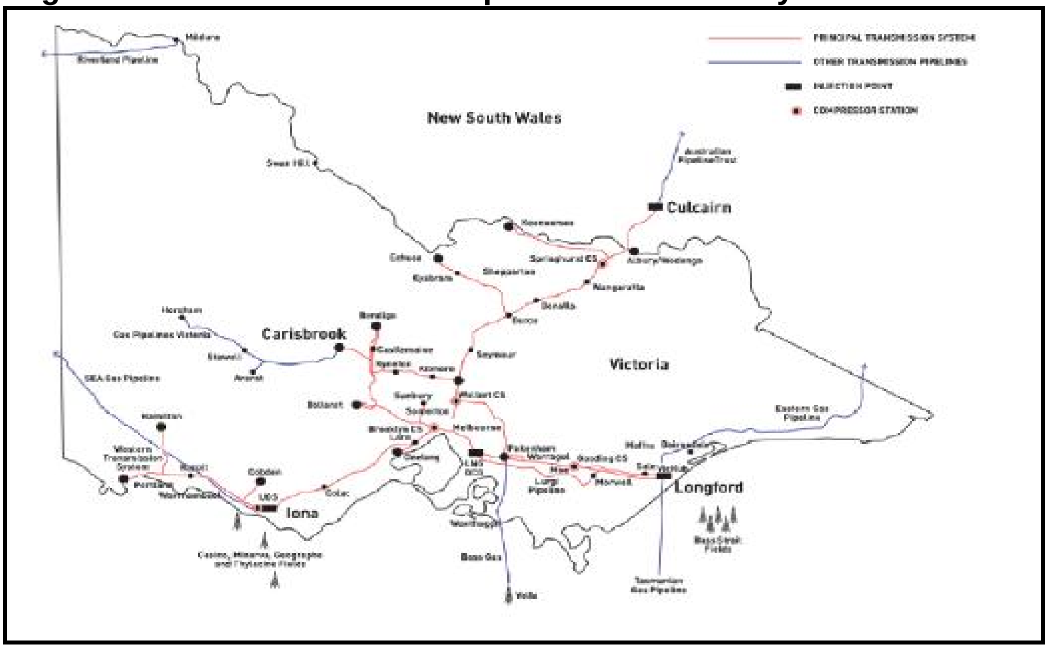
to 10pm and 10pm to 6 am) and updated to reflect revised forecasts and bids. Prices under the new mechanism are calculated for each interval with the price being set at the point where demand and supply is balanced at least cost over that interval. Market participants are only exposed to those changed prices to the extent that their revised schedules or actual behaviour deviate from nominations submitted at the beginning of day.[71]

Victorian Principal Transmission System

The Victorian Principal Transmission System operates as a network and has a number of injection points including Longford, Iona, VicHub, BassGas, Culcairn and the LNG facility at Dandenong (see Figure 3.8). This system is owned by the Australian Pipeline Trust and operates under a 'market carriage' model which is independently operated by VENCorp.

In contrast to the contract carriage model, users of the market carriage model are not required to enter into capacity based transportation contracts. While users do not have reserved capacity on the pipeline they are allocated an authorised maximum daily quantity (AMDQ) which entitles them to transport a maximum quantity of gas on any one day. If a user's AMDQ is breached during periods of congestion then users may have to pay additional charges on the difference between their AMDQ and their actual usage. On any given day a user is simply required to nominate their transportation requirements with VENCorp and their pipeline charges are based on actual throughput.

Figure 3.8: The Victorian Principal Transmission System and other assets



Source: VENCorp, 2006 Gas Annual Planning Report

A description of the manner by which the scheduling and price setting processes are undertaken by VENCorp is set in Box 3.2.

[71] VENCorp, Victorian Gas Market Stage 1 Design Functional Description, 3 April 2006, p.2.

Box 3.2: Operation of the Victorian spot market

In accordance with the MSOR market participants (including gas producers, retailers, storage providers, traders and end-users) are required to be registered with VENCorp.

These participants bid into the market on a daily basis via the Market Information Bulletin Board. Bids consist of the quantities of gas market participants expect to inject into the system and withdraw from the system. Withdrawal bids forecast the participant's hourly demand for the day and is referred to as controllable demand. Injection quantities are the amount a participant plans to inject into the system through any one of the injection points including Longford, Iona, VicHub, BassGas, Culcairn and the LNG facility at Dandenong. There are three types of bids including:

- **daily bids** which are submitted an hour prior to the beginning of each gas day and include hourly forecast consumption and injection rates, they are incorporated into the forecasts that are prepared prior to scheduling;
- **revised-bids** which can be submitted up to an hour prior to the next pricing interval and must be consistent with the daily bid quantity such that a revised bid results in no less than the daily scheduled quantity of gas; and
- **day-ahead bids** and forecast demands are those that are made one and two days prior to a gas day.

Demand that is not provided by participants is 'uncontrollable' and forecast by VENCorp. Using the bidding and scheduling process VENCorp ensures that the difference between the normal rate of injection and withdrawal ('linepack') is sufficient to meet uncontrollable demand and maintain safe operating pressures in the system.

The gas day commences at 6 am Eastern Standard Time and consists of five pricing periods, 6 am to 10 am, 10 am to 2 pm, 2 pm to 6 pm, 6 pm to 10 pm, and 10 pm to 6 am. Schedules are drawn up at the beginning of the day and revised throughout for each pricing period. These schedules are developed by VENCorp using information from:

- market participants including: demand forecasts; participant bids; conditions or constraints in controllable bids; AMDQ and AMDQ credit certificates, hedge nominations and agency hedge nominations;
- physical deliverability requirements for locations with more than one participant at a common point;
- VENCorp's demand forecast override, nodal demand allocation and end of day linepack target;
- data produced via modelling schedules constrained by the physical characteristics of the Principal Transmission System (linepack zones, compressor characteristics, node configuration, withdrawal zones, pipe segments); and
- market participant injection hedge nominations which are used to prioritise tied bids at an injection point, intra-day adjustments for injection or controllable withdrawls and initial conditions and any other input or assumption VENCorp reasonably considers is required to minimise the cost of satisfying demand and maintaining system security.

When additional injections are required to meet demand, VENCorp may schedule quantities that had bid higher than was necessary to clear the market. In such cases the participant is compensated for the price differential in their gas relative to the prevailing market price.

The cited benefits of this market model include the following:

- smaller retailers and other smaller market participants have been able to enter the market more readily because they have been able to avoid the difficulties faced in other jurisdictions in obtaining 'reasonable' commercial contracts;[72]
- the ability to trade imbalances coupled with the pricing signals provided by the spot market enable market participants to manage their short term imbalances and to optimise their portfolios;[73] and
- the separation of asset ownership from market operation enables operational decisions to be undertaken in an impartial manner and thus more acceptable to market participants.[74]

3.4.2. Role of aggregators in the wholesale market

Purchasing gas directly from producers is not the only option available to end users. End-users may also purchase their gas requirements from aggregators. An aggregator is an entity that purchases gas directly from producers in the wholesale market and then on-sells this gas to smaller end users. If an aggregator has transportation arrangements in place then it may also offer to sell gas to users on a delivered basis. An aggregator may operate as a pure aggregator (ie, buying and on-selling gas) or may simply be a retailer or industrial customer selling their excess gas to end-users.

From a retail perspective, aggregators may facilitate the entry of new participants into the retail gas market by:

- reducing the contracting period that would otherwise be faced if the retailer were to purchase its requirements directly from the producers; and
- enabling these new entrants to purchase relatively small quantities of gas while they build up a customer base.

Alinta EATM (a subsidiary of Alinta Limited) is one example of an aggregator operating in eastern Australia. Alinta EATM operates out of the VicHub and purchases gas from the Gippsland Basin. This wholesale gas is then either sold on a delivered basis (ie, in New South Wales via the Eastern Gas Pipeline or in Tasmania via the Tasmanian Gas Pipeline) or directly from the VicHub to end users in the Victorian, New South Wales and Tasmanian markets.[75] Users of Alinta EATM's aggregator services include both Country Energy and EnergyAustralia both of whom have entered into short to medium-term contracts to purchase delivered gas transported into New South Wales via the Eastern Gas Pipeline.[76]

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72 ABARE, Australian Gas Markets Moving Towards Maturity, December 2003, pg. 7.

73 AGL, Submission to the Statutory Review of the Victorian Energy Networks Corporation Issues Paper, pg. 4.

74 AGL, Submission to the Statutory Review of the Victorian Energy Networks Corporation Issues Paper, pg. 5.

75 Alinta, Annual Report 2006, pg 20 and Options for the Development of the Australian Wholesale Gas Market, June 2005, pg. 22.

76 AGL, Undertaking to the Australian Competition and Consumer Commission given for the purposes of Section 87B by the Australian Gas Light Company, 2006, pg. 2.

3.4.3. Role of swaps in the wholesale market

Physical gas swaps also have the potential to influence the manner by which gas is sold in the wholesale market. These physical swaps provide a means for producers to make contracted supplies of gas to areas that they are not physically connected to. While such agreements may affect the amount of gas made available for sale at a particular location and at a particular point in time, they do not eliminate localised pricing differences.

A simple illustration of how a swap contract might work between two producers is set out below. In this example it is assumed that there are two producers located at Ballera and Longford (PB and PL) respectively. The Ballera producer has a gas supply contract with a customer in Sydney for the supply of 10 PJ of gas per annum for delivery to Sydney. A customer in Brisbane (CB) is looking to negotiate a contract for the supply of 5 PJ of gas per annum for delivery to Brisbane.

The Longford producer wishes to contract with a customer in Brisbane but cannot physically deliver its gas to Brisbane through the established network of gas pipelines as shown in Figure 3.9.

Figure 3.9: Gas flows before swap

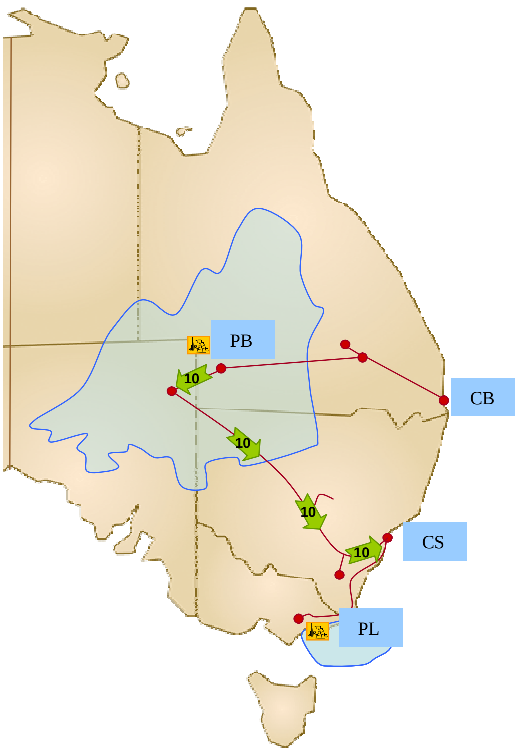
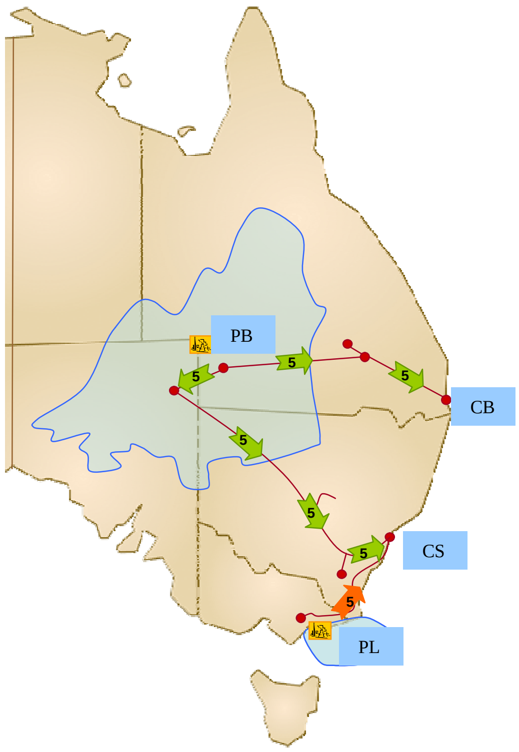


Figure 3.10: Gas flows after swap



Although Longford gas cannot be physically delivered to Brisbane, Ballera gas can and thus Producer L and B may enter into a swap contract. Under such a contract the Ballera producer would supply 5 PJ to the customer located in Brisbane (and in so doing divert 5 PJ of the gas it would otherwise supply to its customer in Sydney) on behalf of the Longford producer, and the Longford producer would supply 5 PJ to the customer located in Sydney on behalf of the Ballera Producer. In order to fulfil their respective supply obligations:

- the Ballera producer would direct 5 PJ of gas to the customer in Sydney and the 5 PJ of gas it swapped with Longford producer to the customer in Brisbane; and
- the Longford producer would direct the 5 PJ of gas it swapped with the Ballera producer to the Ballera producer's customer in Sydney.

It is important to recognise that swap arrangements do not necessarily eliminate localised pricing differences. Rather, swaps simply increase the flexibility that producers and customers have to respond to changes in overall supply and demand conditions across the Eastern states.

In the above example, the incentive for the two producers to enter into the swap arises because there is a difference in the price that customers located in Sydney and customers located in Brisbane are willing to pay for the supply of gas. Under the swap, the Brisbane customer would continue to pay a higher price for gas supplies when compared to a new customer seeking natural gas in Sydney. If this was not the case the Longford producer would not enter into the swap and would instead sell to the customer in Sydney.

In the absence of the swap, the Ballera producer would likely supply the Brisbane customer at the expiry of its contract with the Sydney customer and the Longford producer would supply the needs of the Sydney customer at the expiry of its contract. This is because the Brisbane customer can be most efficiently supplied from a producer located at Ballera. The existence of the swap simply allows this change in gas flows to occur earlier than it otherwise would.

A swap of a similar nature to that described above was entered into by Origin and the South West Queensland producers[77] in 2004. Under the agreement up to 200 PJ of gas was to be swapped through to the end of 2011 (18 PJ per annum) with:

- Origin delivering gas produced in its fields in the Bowen/Surat basin to the South West Queensland producers at Roma which was then to be supplied to the South West Queensland Cooper Basin producer's customers located in south-east Queensland; and
- the South West Queensland producers delivering an equal quantity of gas to Origin at Moomba (transported from Ballera via the Ballera to Moomba pipeline).

In announcing this arrangement Origin stated[78] that the principal benefit of the arrangement was that it could supply its customer base in south eastern Australia without having to construct a major pipeline from the Bowen/Surat Basin to Moomba. For the South West Queensland producers the principal benefit of the arrangement flowed from the swap fee paid by Origin.

In 2006 the swap arrangement was increased from 18 PJ to 40 PJ per annum.[79]

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[77] The South West Queensland producers operate out of Ballera and the joint venture parties include Santos, Origin and Beach Petroleum (formerly Delhi).

[78] Santos, Cooper basin and Origin in major gas swap agreement, 6 May 2004.

[79] Santos, Annual Report 2006, pg. 20.

The ACCC recently considered the extent to which gas swaps may act as a competitive constraint on gas producers within its consideration of Santos' proposed acquisition of QGC. The ACCC concluded that:

> Gas swaps require two willing parties and typically involve an arrangement whereby one party supplies the other party's required volume of gas to a particular destination, and vice versa. Theses arrangements are mutually beneficial and may be used where, due to either the lack of pipeline infrastructure or the direction of gas flow along existing pipeline infrastructure, the parties would not otherwise be able to send its gas to the required destination. The ACCC considered that, particularly due to the limited number of significant players in Southern Queensland, the number of willing parties is likely to be limited.[80]

3.5. Gas prices in eastern Australia

Although on its face, the eastern Australian market appears to be an integrated market, the reality is that the 'market' actually consists of a number of localised sub markets.

For example, in Queensland end users in the south eastern part of the state are proximately located to coal seam methane producers and thus have some choice between purchasing their gas from these producers or producers in Ballera. Pipeline constraints in Queensland, however, mean that end users in the north western part of the state are still wholly reliant on natural gas produced in Ballera. The presence of these pipeline constraints may allow producers of natural gas to maintain a higher price in north western Queensland (where there is less competitive pressure) while charging a lower price to end users in south eastern Queensland (who can choose between natural gas and coal seam methane, depending on their end use requirements). This example demonstrates that disparities in price may emerge within the same jurisdiction as a result of differences in local demand and supply conditions.

The disparate nature of the eastern Australian market means that there is no single market price for gas across eastern Australia. Rather, prices differ across the various jurisdictions and within jurisdictions as a result of differences in local demand and supply conditions. These local demand and supply conditions will in turn be influenced by:

- the type of gas being supplied (ie, conventional natural gas versus coal seam methane);
- the location of reserves relative to the end market;
- the cost of transporting gas to the end location via the relevant transmission pipeline;
- the presence of transportation constraints on the relevant transmission pipeline;
- the number of competing sources of supply and the relative cost of transportation from these competing sources;
- the scope and price of alternative energy sources;
- the value of gas to the end user; and

[80] ACCC, Santos Limited – proposed acquisition of Queensland Gas Company Limited, 7 March 2007, pg. 9.

- the perceptions held about the future demand and supply conditions that will prevail in that jurisdiction over the period that the price is being set.

The prominent role of transportation in this list reflects the fact that gas is typically located some distance from end markets and thus the supply of gas from a particular basin will be inextricably linked to the conditions prevailing in the transportation segment of the supply chain (see section 4.5.2).

The prices paid for gas supplied from a particular basin to buyers in the same end location may also differ as a consequence of differences in:

- the highly customised nature of the terms and conditions of supply; and
- the timing of price reviews across alternative contracts.

Due to the confidential bilateral nature of the wholesale gas supply contracts there is no publicly available information on the actual wholesale ex-plant prices paid by buyers across the alternative basins. However, there have been some anecdotal reports of the ex-plant price paid for conventional natural gas and coal seam methane which have been published by the National Competition Council, Core Collaborative and GasWeek. A summary of these estimates is set out below.

Estimates of conventional natural gas prices

In the National Competition Council's Moomba to Adelaide Pipeline System draft recommendation on coverage[81] reference was made to Cooper/Eromanga ex-plant price estimates prepared by the Essential Services Commission of South Australia's (ESCOSA) and Epic Energy. ESCOSA estimated the Cooper/Eromanga ex-plant price to be $2.90 per GJ in 2004-05 while Epic Energy estimated the price to be between $3.10 and $3.15 per GJ. Epic Energy also provided the National Competition Council with estimates of the ex-plant price in the Otway Basin ($3.10 per GJ) and the Gippsland Basin ($3.05 to $3.10 per GJ).[82]

Epic Energy's estimates for the Cooper/Eromanga and the Gippsland Basin are broadly in line with the estimates presented in Core Collaborative's Australian Gas Sector Outlook. Within this report, Core Collaborative estimated that the ex-plant price in the Gippsland and Cooper/Eromanga basins over 2005 was $3.15 per GJ.[83]

Estimates of coal seam methane prices

Core Collaborative's Australian Gas Sector Outlook also contained an estimate of the price AGL paid for coal seam methane through its contract with QGC which ranged between $2.50 and $2.90 per GJ.[84] This estimate appears to be supported by anecdotal evidence contained

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81 National Competition Council, Draft Recommendation - Application for revocation of coverage of the Moomba to Adelaide Pipeline System under the National Gas Access Regime, November 2005.

82 National Competition Council, Draft Recommendation - Application for revocation of coverage of the Moomba to Adelaide Pipeline System under the National Gas Access Regime, November 2005, pg. 37.

83 Core Collaborative, Australian Gas Sector Outlook, 2006, pg. 83.

84 Core Collaborative, Australian Gas Sector Outlook – Q4 2006 Update, 2007, pg. 11.

in GasWeek which suggests that coal seam methane is being sold in Queensland for approximately $2.50 per GJ.[85]

An estimate of the price paid by AGL for coal seam methane in Sydney can also be estimated by reference to Sydney Gas Company's annual reports. According to the Sydney Gas Company 2005 annual report, gas sales to AGL were 1.6 PJ and its gas sales revenue was $4.5 million. This implies that the price paid by AGL was approximately $3.00 per GJ in 2005.[86]

Divergence in conventional natural gas and coal seam methane prices

This small sample of anecdotal evidence illustrates the diversity of prices prevailing in eastern Australia and, in particular, the divergence that has emerged between the price paid for coal seam methane and conventional natural gas. This divergence largely reflects the fact that coal seam methane exhibits quite different physical and economic characteristics to those exhibited by natural gas and as a consequence can be sold at a price that is lower than that required by natural gas producers.

The ACCC also referred to this divergence in its recent consideration of Santos' proposed acquisition of QGC. Specifically, the ACCC noted that it:

> …considered that the generally higher ex-field prices for gas in the southern states (compared to southern Queensland), combined with the costs of transmission, makes it unlikely that the potential for gas to be supplied from areas outside of southern Queensland would act as a significant price constraint on gas producers in southern Queensland.[87]

Victorian spot price

The Victorian spot price may also be viewed as a proxy for the price being paid for conventional natural gas in the Victorian basins. The spot price that has prevailed in the Victorian market over the period 1 January 2002 to 31 January 2007 (ahead of the change to the new price mechanism) is set out in Figure 3.11. The spot price over this period has ranged from $2.21 per GJ to $9.20 per GJ and has averaged $2.94 per GJ. The seasonal effect on demand is particularly pronounced in Victoria, which can be seen in the spot price that prevails over the winter period in each year.

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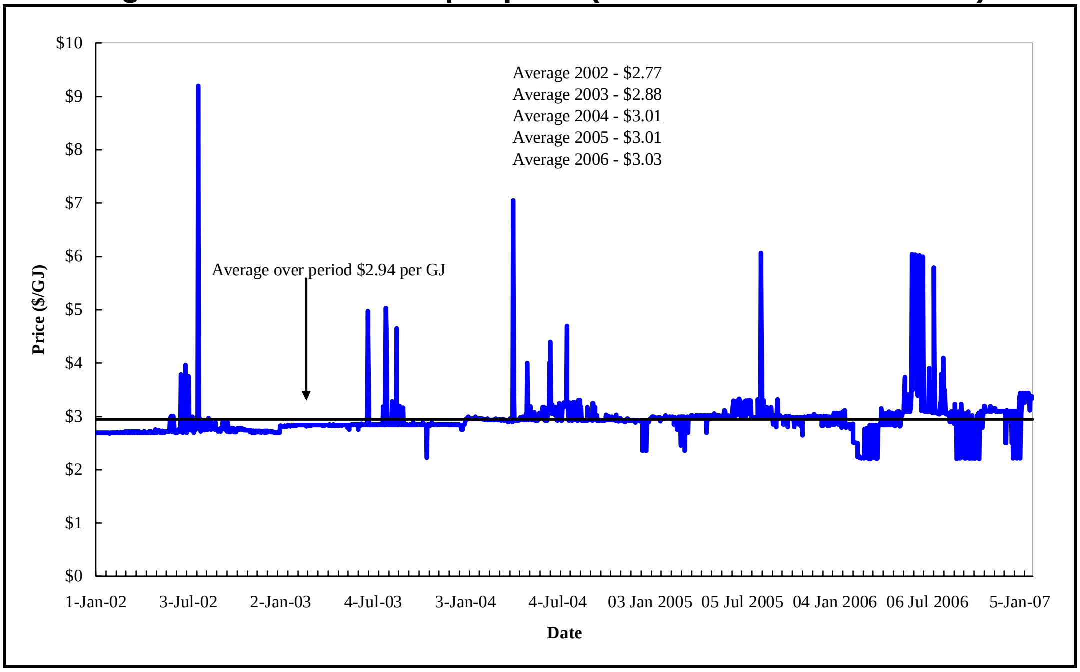
[85] GasWeek 26 August 2005 pg. 2.

[86] Sydney Gas Company, Annual Report 2005.

[87] ACCC, Santos Limited – proposed acquisition of Queensland Gas Company Limited, 7 March 2007, pg. 9.

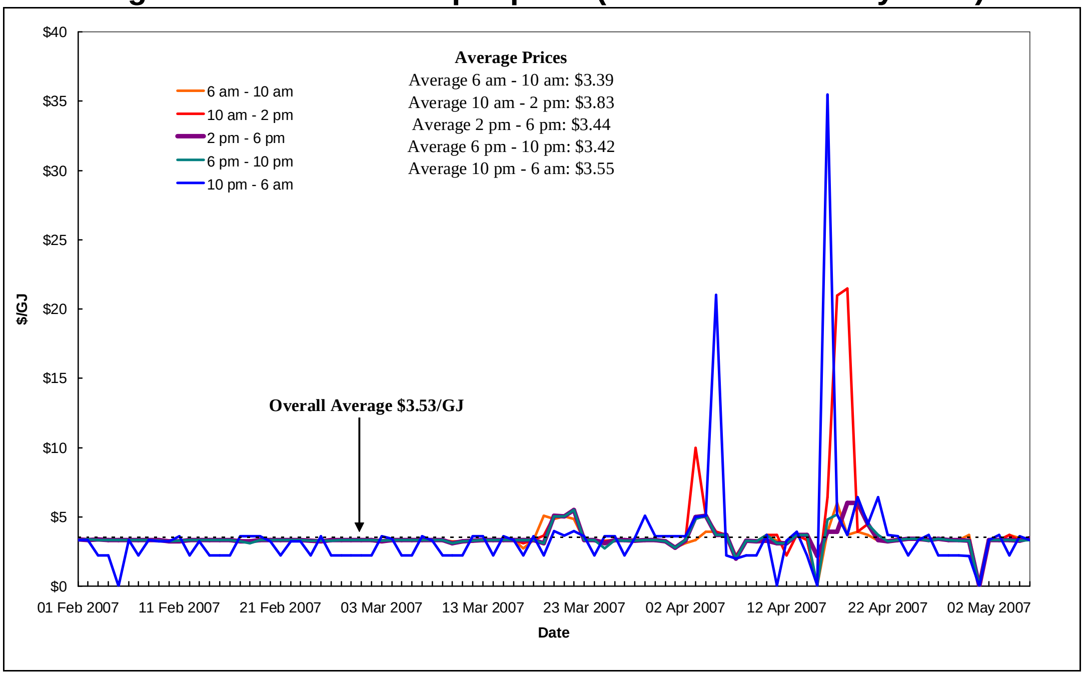
Figure 3.11: Victorian spot price (1 Jan 2002 – 31 Jan 2007)



Source: VENCorp

Figure 3.12 illustrates the price path the Victorian spot price has followed since the introduction of the new price setting mechanism. The average across the scheduled intervals over this period has been $3.53 per GJ although this average has varied across each of the scheduled intervals with the averages peaking in the 10 am to 2 pm and 10 pm to 6 am scheduling intervals.

Figure 3.12: Victorian spot price (1 Feb 2007 – 6 May 2007)



Source: VENCorp

4. Transmission pipelines and other assets

4.1. Overview of major transmission pipelines

Transmission pipelines enable gas to be transported from gas production facilities under high pressure to either a city gate(s) (as the entry point to the distribution system) or to users located on the transmission pipeline. The transmission pipelines that transport gas from the onshore and offshore gas basins to each capital city in eastern Australia include:[88]

- the Moomba to Sydney Pipeline, which extends from Moomba to Sydney, Canberra and Culcairn (the entry point into the Interconnect);
- the Eastern Gas Pipeline, which extends from Longford to Sydney and Hoskinstown (the entry point to Canberra);
- the Moomba to Adelaide pipeline, which extends from Moomba to Adelaide;
- the SEA Gas pipeline, which extends from Port Campbell to Adelaide;
- the South West Queensland pipeline, which extends from Ballera to Roma;
- the Roma to Brisbane Pipeline, which extends from Roma to Brisbane;
- the Tasmanian Gas Pipeline, which extends from Longford to Hobart;
- the Victorian Principal Transmission System, which consists of the Longford to Melbourne Pipeline, the Western Transmission System and the South West Pipeline; and
- the Interconnect which is a bi-directional pipeline linking the Moomba to Sydney Pipeline with the Victorian Principal Transmission System.

Of the nine pipelines listed, four have been constructed over the last seven years including the Eastern Gas Pipeline, the SEA Gas pipeline, the Interconnect and the Tasmanian Gas Pipeline. The construction of these pipelines has facilitated the interconnection of south eastern Australia and in so doing has increased the supply alternatives available to buyers in these markets.

Figure 4.1 provides an overview of the location of each of the transmission pipelines operating in eastern Australia and illustrates the degree of pipeline interconnection in New South Wales, Victoria, the Australian Capital Territory and South Australia.

[88] There are a number of other transmission pipelines operating in each state including the Central West Pipeline, the Central Ranges Pipeline, the Mildura Pipeline, the SESA Pipeline, the South East Pipeline, the Riverland Pipeline, the Queensland Gas Pipeline, the Carpentaria Pipeline and the Dawson Valley Pipeline. Since the focus of this report is the retail markets in each capital city only those pipelines enabling gas to be transported to those end locations have been referred to.

Figure 4.1: Major natural gas pipelines in Eastern Australia

Source: Australian Pipeline Industry Association

A number of pipelines have been proposed over the last five years that could further change the dynamics of the market including the Papua New Guinea pipeline, the Ballera to Moomba interconnect and the Queensland-Hunter gas pipeline. A brief overview of these proposed projects is set out below.

Papua New Guinea pipeline

Until August 2006 gas from Papua New Guinea was seen as the most likely external source of gas in eastern Australia, which would have required the construction of a pipeline which AGL had the option to construct. In August 2006 AGL decided to scale back the Front End Engineering Design on the pipeline and to write off $25.1 million which had already been incurred.[89] In 2007 a decision was made by the project proponents to suspend activities on the Papua New Guinea project.[90]

Ballera to Moomba interconnect

In August 2006, Epic Energy announced that it would undertake a Front End Engineering and Design study and consider the viability of constructing a pipeline linking the South West Queensland Pipeline with the Moomba to Adelaide and the Moomba to Sydney pipelines.[91] The proposed Ballera to Moomba interconnect (the North Gas Link) would enable coal seam methane produced in Queensland to be transported into South Australia, Victoria, the Australian Capital Territory and New South Wales. In November 2006, both Epic Energy and Australian Pipeline Trust announced that they had entered into a Heads of Agreement under which Australian Pipeline Trust would join Epic Energy in undertaking the Front End Engineering and Design study. According to Epic Energy's news release the pipeline capacity would allow for the transport of between 20-90 PJ per annum and would cost between $100 million - $120 million.[92] A final investment decision is expected to be made in June 2007 and if Epic Energy and the Australian Pipeline Trust decide to proceed the pipeline is expected to be constructed in 2008.

Queensland-Hunter gas pipeline

Hunter Gas Pipeline Pty Ltd (a consortium including Hardie Holdings, Weston Aluminium, Hunter Land and ANZ Infrastructure Services) submitted a planning proposal to the New South Wales Minister of Planning in October 2006 for the construction of a pipeline between Wallumbilla and Hexham. Environmental approval has been granted by both the New South Wales Government and the Queensland Government. This proposed pipeline will enable 100 PJ per annum to be transported from Wallumbilla to Hexham at an estimated construction cost of $700 million.[93] While this project has attained environmental approval there is currently no estimated start up date.[94]

4.2. Market structure

Table 4.1 sets out the current ownership interests in the nine transmission pipelines.

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89 AGL Media Release, AGL Posts Record Underlying Full Year Profit, 16 August 2006.

90 Oil Search, 2006 Annual Report, pg. 28.

91 Epic Energy, Epic Energy to undertake study on gas pipeline interconnect, 24 August 2006.

92 Epic Energy and Australian Pipeline Trust, North Gas Link (Ballera to Moomba Interconnect), 13 November 2006.

93 ABARE, Energy in Australia 2006, 2007, pg. 40.

94 http://www.hardieholdings.com/hardie-energy/hunter-queensland-gas-pipeline.html

Table 4.1: Transmission pipeline ownership interests

Pipeline name	Owner
Moomba to Sydney Pipeline (MSP)	Australian Pipeline Trust
Interconnect	Australian Pipeline Trust
Principal Transmission System (PTS)	Australian Pipeline Trust
Roma to Brisbane	Australian Pipeline Trust
South West Queensland Pipeline	Epic Energy (100% owned by Hastings Diversified Utilities Fund)
Moomba to Adelaide Pipeline (MAP)	Epic Energy (100% owned by Hastings Diversified Utilities Fund)
SEA Gas Pipeline	South East Australia Gas Pty Ltd (owned jointly by Australian Pipeline Trust, TRUenergy and International Power)
Eastern Gas Pipeline (EGP)	Alinta is the current service provider. If the Singapore Power International Pty Ltd/Babcock & Brown offer is accepted Singapore Power International will become service provider.
Tasmanian Gas Pipeline	Alinta is the current service provider. If the Singapore Power International Pty Ltd/Babcock & Brown offer is accepted Babcock & Brown Infrastructure will become the service provider.

Drawing on the information contained in Table 4.1 it is apparent that the provision of transmission services to the capital cities in the NEM is relatively concentrated with:

§ the Australian Pipeline Trust having an interest in five out of the nine transmission pipelines;

§ Epic Energy having an interest in two of the pipelines; and

§ Alinta currently having an interest in the remaining two pipelines which will be transferred to Singapore Power International and Babcock & Brown if their joint offer is accepted by Alinta shareholders.[95]

This level of concentration has increased over the last two years following the Australian Pipeline Trust's acquisition of the GasNet assets in Victoria and Origin's one third share of the SEA Gas Pipeline. The recent turnover in this segment of the supply chain has also seen AGL's 30 per cent interest in the Australian Pipeline Trust sold to Alinta[96] and thus the vertical integration that once prevailed in the New South Wales market (with AGL owning the distribution network and a 30 per cent interest in the Moomba to Sydney Pipeline) has been unwound.

4.3. Access to transmission pipelines

At the commencement of the Gas Code, the Moomba to Sydney Pipeline, the Moomba to Adelaide Pipeline, the Principal Transmission System, the South West Queensland pipeline and the Roma to Brisbane Pipeline were deemed to be covered and therefore subject to third party access framework contained in the Gas Code.

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95 A revised offer was made by Babcock & Brown and Singapore Power International on 11 May 2007. It is expected that the scheme will be completed by the end of August 2007 if the offer is accepted by shareholders.

96 If the Singapore Power International and Babcock & Brown Infrastructure offer is accepted then Alinta's interest in Australian Pipeline Trust will be transferred to Alinta shareholders.

In accordance with the provisions contained in the Gas Code the owners of these pipelines have had to submit access arrangements to the AER (formerly the ACCC) for approval which specify the following policies to apply on that pipeline:

§ the services policy;

§ the reference tariffs and reference tariff policy;

§ the terms and conditions;

§ the capacity management policy;

§ the trading policy; and

§ the queuing policy.

At the commencement of the Gas Code both the Roma to Brisbane Pipeline and the South West Queensland pipeline were subject to derogations that precluded the ACCC from reviewing tariffs. The owners of these pipelines were however, still required to submit access arrangements setting out all of the other policies and terms and conditions to apply on the pipelines. The Roma to Brisbane Pipeline's derogation has since expired and the AER has recently reviewed the revised access arrangement including the tariffs. The South West Queensland pipeline's derogation will continue through to 30 June 2016.[97]

In addition to requiring owners of these transmission pipelines to submit access arrangements, the Gas Code also provides prospective users with access to an arbitrator in the event they are unable to reach an agreement with the pipeline owner where an access arrangement is in place.

Following the entry of the Eastern Gas Pipeline, the Interconnect and the SEA Gas pipeline the question of coverage has become quite prominent. In 2000 an application for coverage was made for the Eastern Gas Pipeline and while the Minister for Industry, Tourism and Resources agreed with the National Competition Council's recommendation that the pipeline be covered this decision was later overturned by the Australian Competition Tribunal.[98]

In December 2003 the Minister for Industry, Tourism and Resources decided to revoke coverage on the Moomba to Sydney Pipeline between Moomba and Marsden[99] leaving just 27 per cent of the pipeline between Moomba and Sydney to be regulated.[100] Epic Energy has also sought the revocation of coverage on the Moomba to Adelaide Pipeline and while the National Competition Council has recommended coverage be revoked the final ministerial decision is yet to be made by the South Australian Minister.[101] If the Minister does endorse

[97] South West Queensland Pipeline access arrangement, 1 November 2006, pg. 1.

[98] Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT 3 and 4, 4 May 2001 and 4 July 2001.

[99] Minister for Industry, Tourism and Resources, Application for Revocation of Coverage on Certain Parts of the Moomba to Sydney Gas Pipeline System, Decision, 19 November 2003.

[100] Marsden is located 942 km from Moomba while the distance from Moomba to Sydney is 1,299 km. The laterals of the Moomba to Sydney Pipeline continue to be subject to regulation.

[101] National Competition Council, Application for Revocation of coverage of the Moomba to Adelaide Pipeline System Under the National Gas Access Regime, Final Recommendation, 14 December 2005.

this recommendation then both pipelines enabling the transportation of gas into Adelaide will be unregulated.

Of the nine pipelines providing transmission services to the capital cities in each jurisdiction three are now wholly regulated (Principal Transmission System, South West Queensland Pipeline and the Roma to Brisbane Pipeline), two are partially regulated (the Moomba to Sydney Pipeline and the Interconnect on the Victorian border), one is still awaiting a ministerial decision (the Moomba to Adelaide Pipeline) and three are wholly unregulated (the Eastern Gas Pipeline, the Tasmanian Gas Pipeline and the SEA Gas Pipeline.

4.4. Services offered and tariff structures

The array of services offered by a pipeline depends on whether the pipeline operates as a network or on a point to point basis and whether the pipeline operates under a market carriage or a contract carriage model.

4.4.1. Market carriage versus contract carriage

Transmission pipelines may either operate under a market carriage model or a contract carriage model. The principal differences between these two models lies in the nature of the contractual relationship between the user and the pipeline owner, the manner by which services are obtained and the structure of charges.

Under a market carriage model an independent system operator manages the pipeline and users advise the independent system operator of their daily requirements. Unlike users operating under a contract carriage model, users operating under a market carriage system do not reserve capacity on the pipeline. Users do, however, have an AMDQ allocation which entitles users to transport a maximum quantity of gas on any given day and may be traded with other users. Users operating under a market carriage system generally pay charges based on their actual throughput (ie, $/GJ of throughput).

Under a contract carriage model, the pipeline owner manages the pipeline and users enter into bilateral contracts with the pipeline owner. These contracts set out the service requirements of the user including, where relevant, the firm capacity reservation which is expressed as a maximum daily quantity (MDQ). Where a pipeline is regulated under the Gas Code the pipeline owner is required to have a capacity trading policy that enables users to trade capacity. The ability to trade capacity is of particular relevance on pipelines that are operating at, or close to, capacity.

In eastern Australia the only pipeline operating under the market carriage model is the Victorian Principal Transmission System. All other pipelines providing transmission services to New South Wales, Queensland, South Australia and Tasmania operate under a contract carriage model. The Victorian Principal Transmission System also operates as a network and thus a separate description of the services offered on this system are set out below.

4.4.2. Services provided by point to point transmission pipelines

The services offered by transmission pipelines operating on a point to point basis generally include firm forward transportation services, as available (or interruptible) services and backhaul services.

A firm forward transportation service enables an end user to reserve capacity on the pipeline and to receive a higher priority relative to other buyers that have an 'as available' transportation service. The priority accorded to the firm service will tend to be of greater importance where a pipeline is operating at, or close to, capacity since the 'as available' service will be one of the first services delayed while the firm commitments of the pipeline are met.

Charges for firm forward transportation services are predominantly capacity based although there may be some throughput component in the overall tariff structure. The capacity charge is calculated by reference to the reserved capacity (ie, $/GJ of MDQ) and thus in circumstances where actual quantities transported on any given day are lower than the MDQ, the buyer will still be liable to pay the capacity charge (which is based on the MDQ reservation) and thus the average cost of transporting a GJ of gas rises as actual throughput falls (see Box 4.1).[102]

Box 4.1: Operation of capacity based firm transportation charges

In this example it is assumed that the buyer has a firm capacity reservation of 120 TJ/day (120,000 GJ/day). It is further assumed that the capacity based charge on the pipeline is equal to $0.50 per GJ. Under the terms of this contract the daily capacity charge is $60,000 (ie, $0.50×120,000 GJ).

If the buyer transports 120 TJ/day then the average charge per GJ is simply $0.50.

If the buyer transports 92.3 TJ/day (120 TJ/day ÷ 1.3) then the average charge per GJ will be $0.65 (ie, $60,000 92,307 GJ).

If the buyer transports 60 TJ/day then the average charge per GJ is $1.00 (ie, $60,000 ÷ 60,000 GJ).

The capacity charge in effect operates as a fixed charge and thus as actual throughput falls the average charge per GJ rises.

An as available (or interruptible) service allows a buyer to transport gas without reserving capacity. The priority accorded to this service is, as noted above, lower than that accorded to a firm transportation service. As available tariffs are typically 30 per cent higher than the firm transportation charge but are paid on actual quantities delivered rather than a capacity reservation.[103]

Backhaul transportation services involve the displacement of gas and enable a user to deliver gas into the pipeline at a point upstream of its receipt point. Gas that would otherwise be required upstream is then replaced with the user's delivery and the user's requirements are met by displacing the gas that would otherwise have been required at the upstream delivery point. Aggregate backhaul must be equal to or less than aggregate forward haul transactions and as such the availability of backhaul capacity will vary daily. This variation means that backhaul services are typically only offered on an 'as available' basis rather than a firm basis, which means the service cannot be relied upon by a buyer who requires access to a firm supply of gas.

[102] If the quantities transported exceed the MDQ then the end user may have to pay imbalance or overrun charges.

[103] A service charge will also generally be levied on as available services.

4.4.3. Services provided by the Principal Transmission System

The Principal Transmission System operates as a network and has a number of injection points (including Longford, Iona, VicHub, BassGas, Culcairn and the LNG facility at Dandenong) and withdrawal points. Given these features of the system the services offered on this system include both injection and withdrawal services which attract different charges. These charges are levied by both the owner of the system, the Australian Pipeline Trust, and the system operator, VENCorp.[104]

To calculate the withdrawal and injection charges, the Australian Pipeline Trust assumes that gas is injected at the specified injection zones and then transported to a central hub. Gas is then assumed to be transported from the hub to the relevant delivery point. The injection charge in this context represents the charge associated with transporting the gas from the injection zone to the hub while the withdrawal charge represents the cost of transporting the gas from the hub to the delivery point.[105]

VENCorp also recovers charges from users of the Principal Transmission System. These charges include a registration tariff, withdrawal based tariffs and meter data management tariffs.[106]

4.5. Supply alternatives and their commercial viability

The development of the Interconnect, the SEA Gas Pipeline and the Eastern Gas Pipeline has facilitated the development of a more interconnected market in south eastern Australia. Although retailers in each capital city now technically have access to more than one source of supply, the commercial viability of these alternatives will depend on the transportation costs incurred in delivering the gas from the basin to the final location and the availability of capacity on the relevant pipeline.

For example retailers in Melbourne have a choice of purchasing their gas from:

§ the Gippsland Basin via the Longford to Melbourne pipeline;

§ the Otway Basin via the South West pipeline;

§ the Bass Basin via the Principal Transmission System; and

§ the Cooper/Eromanga Basin via the Moomba to Sydney Pipeline, the Interconnect and the Principal Transmission System.

While the first three of these basins are proximately located to retailers in Melbourne, the Cooper/Eromanga basin is less so and thus retailers would have to take into account the cost of transporting this gas via the Moomba to Sydney Pipeline and the Interconnect when assessing the commercial viability of this alternative. The availability of capacity on each of these alternative pipelines would also be taken into account in this assessment.

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104 Users of the Principal Transmission System must be registered with VENCorp and are also required to enter into a gas transportation deed with VENCorp.

105 GasNet Australia, GasNet Australia, Transmission Tariff Structure & Methodology, 2005.

106 VENCorp, Final Report – Proposed Statutory Gas Budget and Tariffs for 2006/07, April 2006, pg. ii.

Retailers in Adelaide, Canberra, Hobart and Sydney would also have similar options to those described above (see Box 4.2). However, in all of these cases the commercial viability of these choices would differ markedly due to differences in the distance from the relevant gas basin and the transportation tariffs.

In contrast to the interconnected nature of the southern states in eastern Australia, the Queensland market is supplied solely from gas produced in Queensland. Retailers in Brisbane do, however, have a choice between purchasing gas from either the Ballera fields of the Cooper/Eromanga Basin or the coal seam methane fields in south western Queensland.

Box 4.2: Physical supply options for retailers across the capital cities

Retailers in Adelaide

Retailers in Adelaide have the choice of purchasing gas from either:

§ the Gippsland and Bass basins transported via the Principal Transmission System and the SEA Gas Pipeline;

§ the Otway Basin transported via the SEA Gas Pipeline; and

§ the Cooper/Eromanga Basin transported via the Moomba to Adelaide Pipeline.

Retailers in Sydney

Retailers in Sydney have the choice of purchasing gas from either:

§ the Gippsland Basin transported via the Eastern Gas Pipeline or the Principal Transmission System, the Interconnect and the Moomba to Sydney Pipeline;

§ the Bass and Otway basins transported via Principal Transmission System and the Eastern Gas Pipeline or the Interconnect and the Moomba to Sydney Pipeline;

§ the Cooper/Eromanga Basin transported via the Moomba to Sydney Pipeline; and

§ the Sydney Gas Company transported directly into the Sydney distribution system.

Retailers in Canberra

Retailers in Canberra have the choice of purchasing gas from all of the same sources as Sydney excluding the Sydney Gas Company.

Retailers in Hobart

Retailers in Hobart have the choice of purchasing gas from either:

§ the Gippsland Basin transported via the Tasmanian Gas Pipeline;

§ the Bass and Otway basins transported via the Principal Transmission System and the Tasmanian Gas Pipeline; and

§ the Cooper/Eromanga Basin transported via the Moomba to Sydney Pipeline, the Interconnect, the Principal Transmission System and the Tasmanian Gas Pipeline.

Retailers in Brisbane

Retailers in Brisbane have a choice of purchasing their gas from:

§ the Cooper/Eromanga Basin via the South West Queensland Pipeline and the Roma to Brisbane Pipeline; or

§ the coal seam methane fields in south western Queensland via the Roma to Brisbane Pipeline.

4.5.1. Commercial viability

Any decision to purchase gas from an alternative basin will be inextricably linked to the relative cost of transportation from each of the basins being considered and the availability of capacity[107] on each pipeline.

The cost of transporting gas will differ across pipelines, with variations arising as a result of differences in:

- the distance over which the gas must be transported;
- the productive efficiency of the pipelines, which reflects differences in:
  - the size of the pipelines;
  - the number of operational compressors;[108]
  - the operating costs of the pipelines;
  - the overall utilisation of the pipeline's capacity; and
- the pricing structure adopted on the pipeline.

When comparing the transportation costs between two pipelines, generally, the greater the distance over which gas is transported the higher is the cost. However, there are instances where this relationship may not hold. These include, for example, where capacity on a pipeline is restricted and prices are being used to ration capacity, or where a pipeline is underutilised and the capital costs are recovered from a relatively low volume base.

4.5.2. Transportation costs and capacity of the transmission pipelines

Table 4.2 provides an overview of the pertinent features of each of the nine transmission pipelines enabling gas to be transported to capital cities in eastern Australia including pipeline capacity and transportation distances and an indicative estimate of the transportation charges that would be incurred under a firm transportation service to the directly connected capital cities assuming a 100 per cent swing factor.

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[107] The capacity of a pipeline is a function of the diameter and the length of the pipeline. The capacity will also depend on pressure between two ends of the pipeline which may be enhanced through the use of compressors.

[108] Compressors allow the capacity of the pipeline to be increased.

Table 4.2: Transmission pipelines capacity, regulation and tariffs

Retail Markets	Pipeline name	Regulation	Capacity as currently configured and known capacity constraints
Sydney and Canberra	Moomba to Sydney Pipeline (MSP)	Unregulated between Moomba and Marsden	470 TJ/day on mainline, 46 TJ day on Dalton to Canberra lateral (given the presence of stress corrosion cracking on this pipeline this capacity may vary)* There are no known capacity constraints on this pipeline[w]
	Eastern Gas Pipeline (EGP)	Unregulated	178 TJ/day to Horsley Park 140 TJ/day on ActewAGL interconnector to Canberra* Additional compression will be required to meet transportation obligations from 2009[##]
Sydney, Canberra and Melb	Interconnect	Unregulated on the NSW side and regulated on the Victorian side	Bi-directional Southbound capacity estimated to be 50 TJ/day and maximum northbound approximately 30 TJ/day Northbound capacity may be constrained to 10 TJ/day in winter by conditions on the Victorian PTS during peak demand periods in Victoria[#]
Melb	Principal Transmission System (PTS)	Regulated	Longford to Melbourne Pipeline 1,030 TJ/day (combined over Longford, VicHub and BassGas injection points) South West Pipeline from Iona 260 TJ/day Western Transmission System 28 TJ/day[#]
Adelaide	Moomba to Adelaide Pipeline (MAP)	NCC recommended revocation of coverage yet to be endorsed by Minister	418 TJ/day Following the entry of the SEA Gas pipeline there are no longer any capacity constraints on this pipeline **
	SEA Gas Pipeline	Unregulated	300 TJ/day ** Firm capacity on this pipeline was fully contracted at the time the pipeline was constructed to the original joint owners, Origin Energy Retail, TRUenergy (some of this capacity has been transferred to AGL through its acquisition of the Torrens power plant) and Pelican Point. While firm capacity was fully contracted there is currently an offer for the firm transport of 8 TJ/day. ww
Brisbane	South West Queensland Pipeline	Regulated	130 TJ/day There are no known capacity constraints on this pipeline ^^
	Roma to Brisbane	Regulated	Licensed capacity 180 TJ/day with peak capacity of 203 TJ/day The capacity of this pipeline is fully contracted. ^
Hobart	Tasmanian Gas Pipeline	Unregulated	Longford to Bell Bay 129 TJ/day Hobart Lateral 31 TJ/day There are no known capacity constraints on this pipeline.[##]

Retail Markets	Pipeline name	Tariff Structure for firm transportation services	Pipeline Distance to Retail Markets	Indicative tariffs (100% swing factor)as at 1 Jan 2007
Sydney and Canberra	Moomba to Sydney Pipeline (MSP)	Two part tariff consisting of a capacity tariff ($/km/GJ of MDQ) and a throughput tariff ($/km/GJ)	1,299 km to Sydney	$0.6774/GJ [1]
			1,189 km to Canberra	$0.6201/GJ [1]
			1,252 km to Culcairn	$0.6529/GJ [1]
	Eastern Gas Pipeline (EGP)	Zonal capacity tariff ($/GJ of MDQ).	795 km to Sydney	$1.0378/GJ[2]
			570 km to Canberra	$0.7844/GJ[2]
Syd, Cbr and Melb	Interconnect	Two part tariff consisting of a capacity tariff ($/km/GJ of MDQ) and throughput tariff ($/km/GJ).	n.a.	n.a.
Melb	Principal Transmission System (PTS)	Zonal injection and withdrawal tariffs payable to the pipeline owner with distinction drawn between Tariff V and Tariff D customers. Separate fees and tariffs payable to VENCorp.	Longford to Melbourne 173 km	$0.2319 [3] ex VENCorp charges
			South West Pipeline n.a.	$0.2362 [3] ex VENCorp charges
Adelaide	Moomba to Adelaide Pipeline (MAP)	Three part charge consisting of a capacity charge ($/GJ of MDQ), a throughput charge ($/km) and a monthly customer charge ($).	781 km	$0.5539 [4]
	SEA Gas Pipeline	Information on the tariff structure used on this pipeline is not publicly available.	680 km	$0.72/GJ [5]
Brisbane	South West Queensland Pipeline	Two part tariff consisting of a capacity tariff ($/GJ of MDQ) and a throughput tariff ($/GJ)	755 km	$0.848/GJ [6]
	Roma to Brisbane	Two part tariff consisting of a capacity tariff ($/GJ of MDQ) and a throughput tariff ($/GJ)	410 km	$0.453/GJ [7]
Hobart	Tasmanian Gas Pipeline	Zonal capacity tariff ($/GJ of MDQ).	734 km	$1.8545/GJ[2]

Notes:

* National Competition Council, Final Recommendation Moomba to Sydney Pipeline System – Revocation Applications Under the National Gas Code, 2002, pg. 58 ** National Competition Council, Draft Recommendation - Application for revocation of coverage of the Moomba to Adelaide Pipeline System under the National Gas Access Regime, November 2005, pp. 21 and 39. [#] VENCorp, Gas Annual Planning Report, 2006, pg. 29-30. [##] Alinta Infrastructure Holdings Initial Public Offering, 2005, and http://www.aih.net.au/assets/EGP/transportServices.aspx ^ AER, Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline, 20 December 2006, pg. 7. ^^ Epic Energy http://epic.onlinepublicity.net/index.php?id=31 WACCC, East Australian Pipeline Limited Access Arrangement for the Moomba to Sydney Pipeline, Final Decision, pg. 168 and WW http://www.seagas.com.au/current_offers.htm

1. Calculated using information from Australian Pipeline Trust website http://www.pipelinetrust.com.au/4/4-2set.html 2. Current tariffs from Alinta Infrastructure Holding website http://www.aih.net.au/assets/download/EGP/2007/070206EGPTariffs1Jan07.pdf 3. Current tariffs taken from GasNet Transmission Tariff Calculator http://www.gasnet.com.au/Main.asp?id=39 4. Calculated using regulated tariffs from 2002 Access Arrangement and escalating these by 95 per cent of CPI from 1999 to 1 Jan 2007 see Access Arrangement for the Moomba to Adelaide Pipeline System, 10 December 2003. 5. Current offer appearing on SEA Gas website http://www.seagas.com.au/ 6. Calculated by escalating derogated (based on 1 July 1997 dollars) by 75 per cent of CPI to 1 Jan 2007 see Epic Energy, Ballera to Wallumbilla Natural Gas Pipeline, Annexure A, Access Principles, 1 July 2006, pp. 15 and 25. 7. AER, Final Approval - Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline, 28 March 2007.

Examining the capacity column in Table 4.2 it is apparent that there are firm capacity constraints on the northbound capacity of the Interconnect, the Roma to Brisbane Pipeline and the SEA Gas Pipeline.[109] There may also be some capacity constraints on the Eastern Gas Pipeline from 2008-09 when TRUenergy commences supplying its gas fired power generation plant in Tallawarra.[110] These capacity constraints in effect limit the choice of supply alternatives for prospective retailers in the Sydney, Canberra, Adelaide and Brisbane markets seeking firm transportation services . In the presence of these constraints prospective retailers in Sydney, Canberra and Adelaide the choice of supply would be limited to the Cooper/Eromanga Basin.[111] In Brisbane prospective retailers would have the same gas supply choice (ie, Cooper/Eromanga and the Coal Seam Methane fields), however, it would either need to enter into an arrangement with existing users of the pipeline to obtain spare capacity or alternatively agree to pay a negotiated tariff which includes the cost of expanding the current capacity of the Roma to Brisbane Pipeline.[112]

The indicative tariff[113] column in Table 4.2 also demonstrates that while locations such as Sydney, Canberra and Adelaide can source gas from two or more locations the relative costs of transportation differ. The difference in transportation costs to these three end markets can be seen in Figure 4.2. It is important to recognise in this context that while this comparison has been made on the basis of published or regulated tariffs, pipeline owners may negotiate a lower tariff to encourage greater utilisation of their pipeline.

Examining this figure it is apparent that the relative cost of transporting gas from the Cooper/Eromanga Basin to Sydney, Canberra and Adelaide is substantially cheaper than transporting gas to Sydney from the Gippsland Basin and Adelaide from the Otway Basin. In the presence of these differences one would expect a retailer to take these costs into account when determining which basin to source their gas from and when negotiating the ex-plant price with producers.

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[109] While the SEA Gas Pipeline was fully contracted on a firm basis to the original owners there is currently an offer for firm transportation services up to 8 TJ/day (2.9 PJ per annum).

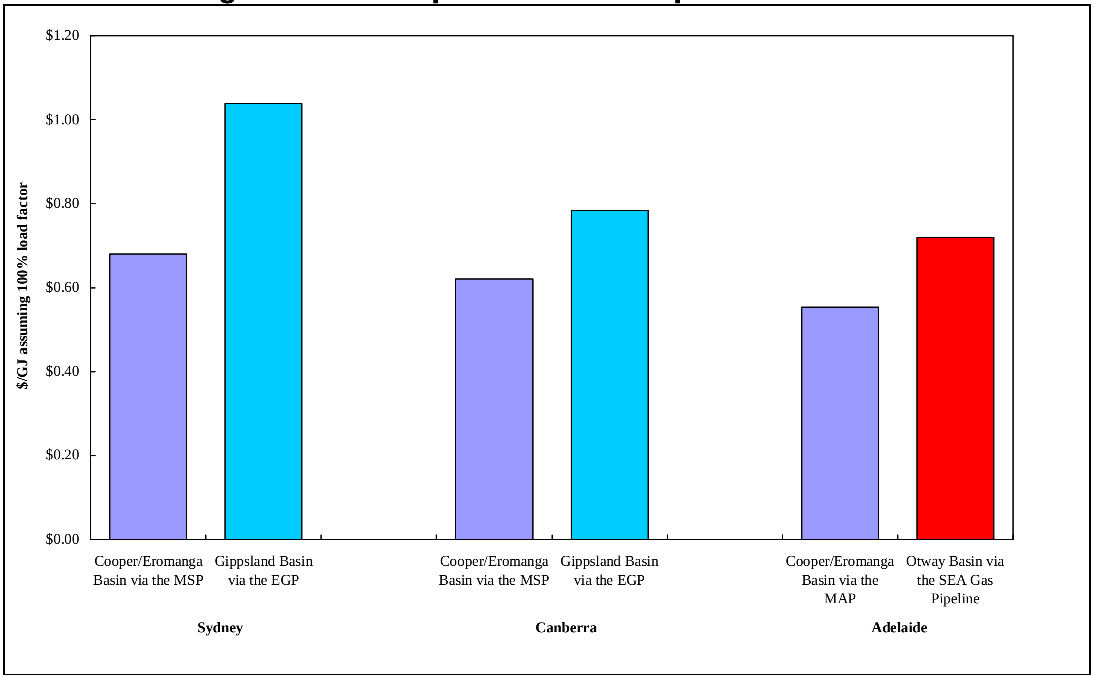
[110] AIH, AIH Announces New EGP Contracts with TRUEnergy, 30 May 2006.

[111] The Sydney Gas Company is a further source of gas in Sydney, however, all the quantities have been contracted to AGL.

[112] AER, Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline, 20 December 2006, pg. 220.

[113] These estimates are based on published information and it must be recognised that these represent the maximum price payable. That is, users may negotiate a lower transportation charge.

Figure 4.2: Comparison of transportation costs



Although the transportation costs will generally be borne by the retailer they may influence the negotiated ex-plant price and thus there may be some sharing of transportation costs between the buyer and producers. The extent to which this occurs will depend on the local supply and demand balance. In general, a greater proportion of transportation costs will be borne by the party that is least able to respond to a change in price, which will largely depend on the demand and supply balance at each location.

For example, if a buyer is located in an area that can be supplied by two alternative gas basins and pipeline networks, then its consideration of the ex-plant price will take into account, amongst other things, differences in the transportation costs across the two pipeline networks. The ability of the buyer to source gas from alternative locations generally means that a greater proportion of total transportation costs are likely to be borne by the producer. Whether or not a producer faced with relatively high costs for transporting gas to one end market will accept a lower ex-plant price ultimately depends on the existence of alternative, closer markets or, in economic terms, the ‘opportunity cost’ involved in supplying gas to that particular buyer location. The willingness of a producer to compete on a delivered basis will also depend on the extent to which the ownership structure of the competing sources of supply differs.

If a buyer did not have access to another source of supply, and the producer could sell gas to a number of locations, then the buyer’s ability to respond by making use of alternative supply options would be limited. In this case, a greater proportion of the transportation costs would be borne by the buyer, and this would be reflected in a higher delivered price.

The proportion of transport costs borne by producers and buyers therefore depends on the demand and supply balance at each location and the relative position of the producer and buyer. Where the cost of transporting gas or the demand and supply balance are different as between one production or demand location and another, it is reasonable to expect there to be differences in both the ex-plant and delivered price accepted by producers and paid by buyers for the supply of gas.

4.6. Other wholesale market assets

There are a number of other assets that are utilised within the wholesale gas market including the Ballera to Moomba pipeline, the Western Underground Storage System, the VicHub and the Dandenong LNG Storage Facility. A brief description of these assets is set out below.

4.6.1.1. Ballera to Moomba pipeline

The Ballera to Moomba pipeline is owned by the South West Queensland and Cooper Basin Producers and is used to transport raw gas, natural gas liquids and condensates produced by the South West Queensland Producers in Ballera to Moomba.[114] Once the raw gas and condensates reach Moomba:

- the raw gas is processed at the Moomba production facilities (owned by the South Australian Cooper Basin Producers) and then sold into the South Australian, New South Wales and Victorian markets;
- the natural gas liquids are subject to a refrigeration process (to allow for the additional recovery of liquids) and are then transported to Port Bonython along with stabilised crude oil and condensate via an oil pipeline; and
- any ethane produced in either the Ballera or Moomba fields is transported to Sydney via a dedicated ethane pipeline owned by the Australian Pipeline Trust.

The capacity of this pipeline as it is currently configured is approximately 82 TJ/day.[115]

4.6.1.2. VicHub[116]

The VicHub is an interconnect facility linking the Eastern Gas Pipeline, the Tasmanian Gas Pipeline and the Principal Transmission System. The VicHub also includes part of the Longford compressor station. The capacity of the VicHub as it is currently configured is 135 TJ/day, however, only 110 TJ/day is available on an interruptible basis.[117] The VicHub is currently owned by Alinta. If the Singapore Power International Pty Ltd and Babcock & Brown offer is accepted then Singapore Power will acquire this asset.

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[114] Since this pipeline transports raw gas it cannot be covered under the National Third Party Access Code for Natural Gas Pipeline Systems.

[115] National Competition Council, Application for Revocation of coverage of the Moomba to Adelaide Pipeline System Under the National Gas Access Regime, Final Recommendation, 14 December 2005, pg. 19.

[116] This section has been drafted using information from the Alinta Infrastructure Holdings Initial Public Offering, 2005, VENCorp, Gas Annual Planning Report 2006 and the Babcock & Brown / Singapore Power Offer to Alinta Shareholders, 2 May 2007.

[117] VENCorp, Gas Annual Planning Report 2006, pg. 23.

4.6.1.3. Western Underground Storage[118]

The Western Underground Storage facility (owned by TRUenergy) is located in a depleted gas field in Iona (near Port Campbell in Victoria) and is connected to the Principal Transmission System and the SEA Gas Pipeline. This facility commenced operations in 1999.

This facility stores gas in a porous sandstone reservoir and is used by retailers and producers to manage the intra-year variability in their gas demand. By placing gas in the storage facility in the summer when it has surplus supply (or alternatively when the market price is low) and withdrawing the gas in the winter (or alternatively when the market price is high) a retailer can meet its peak demand without:

§ having to pay for a higher swing factor on its gas supply contract to meet the demand over the winter months; or

§ purchasing gas on the spot market and thereby avoids the spikes in spot prices that are usually associated with a spike in demand.

Users of this facility can also purchase the maximum hourly withdrawal quantity from storage for injection into the market when it has insufficient supply or if the market price is high.

The minimum contract capacity for this facility is 20 TJ/day of storage withdrawal. The storage fees levied by TRUenergy consist of a two part charge with the fixed capacity charge applied to maximum hourly withdrawal quantity and storage volume while the variable charge is applied to throughput. According to VENCorp the capacity of this storage facility is 12.2 PJ.[119]

The Victorian Department of Primary Industries has estimated that over 2004-05, 7.8 PJ of gas was injected into this facility and 6.6 PJ was extracted.[120]

4.6.1.4. LNG Storage Facility[121]

The LNG storage facility is located at Dandenong and is owned by the Australian Pipeline Trust. This facility is used to liquefy natural gas, store the liquefied gas as LNG and then regasify the LNG before sending the gas back into the Principal Transmission System. This facility is used to balance intra-day demand and supply and is also used to build up linepack. The capacity of the facility is 659 TJ and 461 TJ is available to gas market participants on a contract basis while 165 TJ is held in reserve for VENCorp for system security.[122]

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118 The information contained in this section has been drafted using information from the TRUenergy website (http://www.truenergy.com.au/Production/Iona/index.xhtml).

119 VENCorp, Gas Annual Planning Report 2006, pg. 23.

120 PESA, Victorian Supplement, 2006, pg. 10.

121 The information contained in this section has been drafted using information from the VENCorp, Gas Annual Planning Report 2006, pg. 24 and information on the GasNet website (http://www.gasnet.com.au/Main.asp?id=29)

122 The remaining 32.9 TJ is contracted to BOC for the liquefacation process.

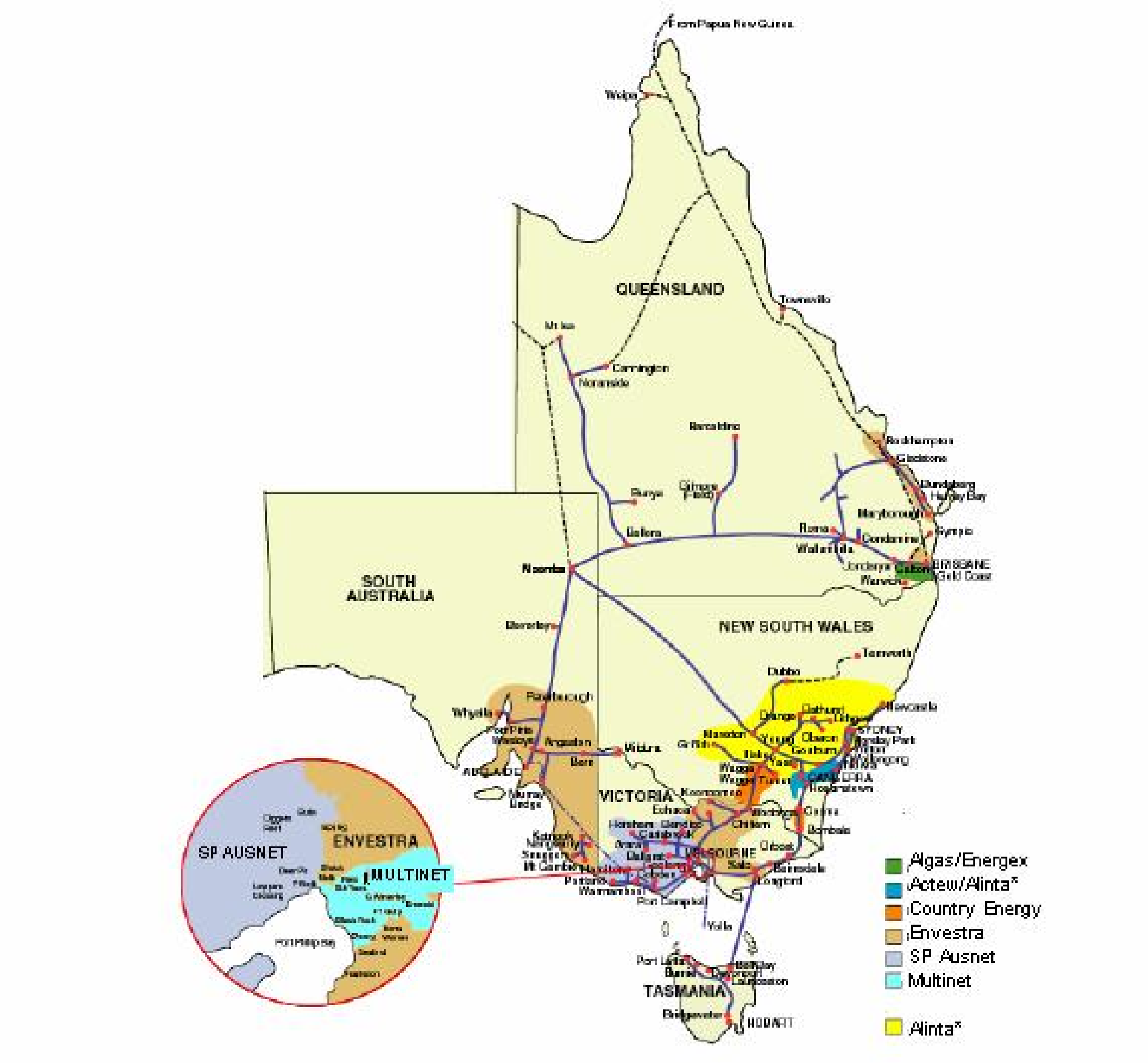
5. Distribution systems

5.1. Overview of distribution systems in eastern Australia

Gas that is to be supplied to customers connected to the distribution system is transported from the relevant gas production facility via the transmission pipeline to the city gate(s). At the city gate station, gas leaving the transmission pipeline is metered and odorised. The pressure is also reduced at this stage to enable the gas to be transported through the low pressure distribution system.

Figure 5.1 illustrates the distribution systems operating in eastern Australia including the current ownership of these systems.

Figure 5.1: Distribution systems in eastern Australia



Source: Australian Gas Association, 2003 updated by NERA for recent acquisitions.
* If the Singapore Power International Pty Ltd /Babcock & Brown offer for Alinta is accepted then Singapore Power International Pty Ltd will take over Alinta's interest.

5.2. Market structure

Table 5.1 provides an overview of the distribution systems operating in the capital cities of eastern Australia and sets out the ownership interests in each system and the sources of gas supplying those systems.

Table 5.1: Distribution system ownership interests

Pipeline name	Service Provider and Ownership interests	Description of the system and sources of gas
New South Wales Gas Distribution Network	Alinta is the current service provider. If the Singapore Power International Pty Ltd /Babcock & Brown offer is accepted. Singapore Power International Pty Ltd will become the service provider.	The distribution system in Sydney enables gas produced by the Sydney Gas Company and gas transported via the EGP and the MSP to be sold in Sydney. The entry points for the MSP and the EGP are Wilton and Horsley Park respectively. Gas produced by the Sydney Gas Company at Camden is supplied directly into the distribution system. The potential sources of gas include Gippsland, Otway, Bass and Cooper/Eromanga basins and coal seam methane produced in Camden.
ActewAGL Gas Network (Canberra)	Actew Corporation and Alinta have a 50:50 joint venture arrangement. If the Singapore Power International Pty Ltd /Babcock & Brown offer for Alinta is accepted then Singapore Power International Pty Ltd will take over Alinta's interest.	The distribution system in Canberra enables gas transported via the EGP and the MSP to be sold into Canberra. The entry points for these two pipelines are Hoskinstown and Dalton respectively. A second pipeline built between Hoskinstown and Fyshwick acts as a storage vessel during peak times. The potential sources of gas include Gippsland, Otway, Bass and Cooper/Eromanga basins.
Stratus Network Systems (Melbourne)	Envestra Ltd is the current service provider 16.6% of Envestra Ltd is owned by Australian Pipeline Trust, 16.6% is owned by Cheung Kong Infrastructure Holdings (Malaysia) Limited and the remainder is held by public investors.	The Stratus Network System enables gas transported via the Principal Transmission System to be sold into northern, outer eastern and southern areas of Melbourne. The potential sources of gas include Gippsland, Otway, Bass and Cooper/Eromanga basins.
Multinet Gas Systems (Melbourne)	Multinet Gas (DB No. 1) Pty Ltd and Multinet Gas (DB No. 2) Pty Ltd are the joint service providers of the Multinet Gas Systems. Multinet is jointly owned by DUET (who hold a 79.9% interest) and Alinta (who hold a 20.1% interest). If the Singapore Power International Pty Ltd /Babcock & Brown offer is accepted Babcock & Brown Infrastructure will acquire Alinta's interest.	The Multinet Gas System enables gas transported via the Principal Transmission System to be sold into the eastern and south eastern suburbs of Melbourne The potential sources of gas include Gippsland, Otway, Bass and Cooper/Eromanga basins

Pipeline name	**Service Provider and Ownership interests**	**Description of the system and sources of gas**
Westar Energy Systems (Melbourne)	SPI Networks (Gas) Pty Limited is the current service provider SPI Networks (Gas) Pty Limited (SPI Gas) is a wholly owned subsidiary of SP Australia Networks (Distribution) Limited which is part of the SP AusNet group. Singapore Power International Pty Ltd (SPI) holds a 51% interest in SP AusNet and the remaining 49% interest is held by public investors.	The Westar Energy System enables gas transported via the Principal Transmission System to be sold into the western areas of Melbourne. The potential sources of gas include Gippsland, Otway, Bass and Cooper/Eromanga basins.
South Australian Gas Distribution System	Envestra Ltd is the current service provider. 16.6% of Envestra Ltd is owned by Australian Pipeline Trust, 16.6% is owned by Cheung Kong Infrastructure Holdings (Malaysia) Limited and the remainder is held by public investors.	The distribution system in Adelaide enables gas transported via the SEA Gas and the MAP to be sold into Adelaide. There are three city gates that enable gas transported from the MAP into Adelaide (Elizabeth, Gepps Cross and Taperoo) and one city gate that enables gas transported from the SEA Gas pipeline (Cavan). The potential sources of gas include Gippsland, Otway, Bass and Cooper/Eromanga basins.
Allgas Energy Distribution System (Brisbane)	Allgas Energy Ltd is the current service provider. Allgas Energy Ltd is owned by Energex which is a Queensland government owned corporation.	The distribution system in south Brisbane enables gas transported via the South West Queensland Pipeline and the Roma to Brisbane pipeline to be sold into Brisbane. The distribution network operated by Energex supplies gas to customers south of the Brisbane River. The sources of gas supply include the Cooper/Eromanga basin and CSM fields in south west Queensland.
Envestra Distribution System (Brisbane)	Envestra Ltd is the current service provider. 16.6% of Envestra Ltd is owned by Australian Pipeline Trust, 16.6% is owned by Cheung Kong Infrastructure Holdings (Malaysia) Limited and the remainder is held by public investors.	The distribution system in south Brisbane enables gas transported via the South West Queensland Pipeline and the Roma to Brisbane pipeline to be sold into Brisbane. The distribution network operated by Envestra supplies gas to customers north of the Brisbane River. The sources of gas supply include the Cooper/Eromanga basin and CSM fields in south west Queensland.
Tasmanian Distribution System	Powerco Tasmania is the current service provider. Powerco Tasmania is a wholly owned subsidiary of Powerco Limited (New Zealand)	The distribution system in Hobart is connected to the Tasmanian Gas Pipeline which transports gas from Victoria to Bell Bay and onto Hobart. Stage 1 of this system has been constructed and Stage 2 is due to be completed in mid 2007. The potential sources of gas include Gippsland, Otway, Bass and Cooper/Eromanga basins.

Examining the service providers operating across each jurisdiction it is apparent that there is some level of concentration of ownership of the distribution assets with both Alinta (or Singapore Power if the Singapore Power/Babcock & Brown offer is accepted by Alinta shareholders) and Envestra each having an interest in three distribution systems.

Asset ownership is an area that has undergone significant change over the last year commencing with Alinta's acquisition of AGL's distribution assets in New South Wales, AGL's 50 per cent interest in the ActewAGL distribution network and the 30 per cent interest in the Australian Pipeline Trust. The divestment of AGL's distribution assets and its 30 per cent interest in the Moomba to Sydney Pipeline in effect represented a vertical separation of AGL's retail interests from its transportation interests. The AGL assets acquired by Alinta are currently the subject of a proposed acquisition by Singapore Power International and Babcock and Brown. If this proposal is accepted by Alinta shareholders then the gas distribution system assets[123] will be acquired by Singapore Power International. [124]

Origin Energy's recent sale of its 17 per cent interest in Envestra and its interest in the SEA Gas pipeline to the Australian Pipeline Trust may also be viewed as a vertical separation of its retail interests from its transportation interests. [125]

5.3. Services offered and tariff structures

Apart from the Tasmanian distribution system, the distribution systems operating in each capital city in eastern Australia are currently regulated by their respective jurisdictional regulators in accordance with the Gas Code and other regulatory instruments.

Table 5.2 provides a description of the transportation services available on each of the systems and the tariff structures applying to each of these services. An interesting point to note from this table is that the tariffs applying on each of these systems tend to be expressed as a function of the user's maximum hourly quantity, the user's maximum daily quantity, a daily charge or are subject to a minimum bill. As a consequence the distribution costs incurred by users will be largely fixed.

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[123] Under the proposed acquisition the 30 per cent interest in the Australian Pipeline Trust will be transferred to Alinta shareholders.

[124] Babcock & Brown, Enhanced Recommended Proposal for Alinta, 11 May 2007, Appendix 1.

[125] Australian Pipeline Trust, APA Group to Acquire Origin Energy Networks, 4 April 2007.

Table 5.2: Distribution pipelines services and tariff structures

Retail Markets	Pipeline name	Service	Tariff Structure
Sydney [1]	New South Wales Gas Distribution Network	Tariff Service for one or more tariff delivery points.	The charges for this service consist of a fixed charge and declining block throughput charges.
		Capacity Reservation Service applies to customers that are reasonably expected to require 10 TJ per annum.	The charge for this service consists of a capacity charge ($/GJ of MDQ per annum), throughput charge ($/GJ) and overrun charges.
		Managed Capacity Reservation Service differs from the capacity reservation service only in so far as no overrun charges are levied.	The charge for this service consists of a capacity charge ($/GJ of MDQ per annum) and throughput charge ($/GJ).
		Throughput Service applies to customers with requirements greater than 10 TJ per annum at a single delivery point.	The charge for this service is a single throughput charge ($/GJ) and there is a minimum bill based on 10 TJ per annum.
Canberra [2]	ActewAGL Gas Network	Tariff Service for one or more tariff delivery points.	The charges for this service consist of a fixed charge and declining block throughput charges.
		Capacity Reservation Service applies to customers using non-tariff delivery points that have reserved capacity.	The charge for this service consists of a capacity charge ($/GJ of MDQ per annum), throughput charge ($/GJ) and overrun charges.
		Managed Capacity Reservation Service differs from the capacity reservation service only in so far as no overrun charges are levied.	The charge for this service consists of a capacity charge ($/GJ of MDQ per annum) and throughput charge ($/GJ)
		Throughput service applies to customers with requirements greater than 10 TJ per annum at a single delivery point.	The charge for this service is a single throughput charge ($/GJ) and there is a minimum bill based on 10 TJ per annum.
Melbourne [3]	Stratus Network Systems	Tariff D applies to customers with requirements greater than 10 TJ pa or greater than 10 GJ per hour.	The charge for this service consists of a declining block $/GJ of MHQ charge.
		Tariff V applies to all other customers.	The charge for this service consists of a fixed daily charge ($/day) and a declining block throughput charge which varies depending on whether the gas is delivered during peak or off peak times.

Retail Markets	Pipeline name	Service	Tariff Structure
Melbourne[3]	Multinet Gas Systems	Tariff V residential and non-residential.	The charge for this service consists of a fixed daily charge ($/day) and a declining block throughput charge which varies depending on whether the gas is delivered during peak or off peak times. The charge also varies depending on the season the gas is purchased with higher charges over May and October shoulder periods.
		Tariff L non residential applies to customers with requirements greater than 5 TJ per six months.	The charge for this service consists of a maximum demand charge ($/GJ/day) based on the 12 month rolling maximum demand and a declining block throughput tariff ($/GJ). The latter of these charges varies depending on whether the gas is delivered during peak or off peak periods and the season the gas is purchased.
		Tarff D non- residential applies to customers with requirements greater than 10 TJ in the preceding twelve months.	The charge for this service consists of a single charge based on $/GJ of MHQ per day.
	Westar Energy Systems	Tariff V domestic and Tariff V non-domestic.	The charge for this service consists of a fixed daily charge ($/day) and a declining block throughput charge which varies depending on whether the gas is delivered during peak or off peak times.
		Tariff D applies to customers with requirements greater than 10 TJ per annum.	The charge for this service consists of a single charge based on $/GJ of MHQ
Adelaide[4]	South Australian Gas Distribution System	Tariff R applies to customers where gas is used for domestic purposes 50% of the time.	The charge for this service comprises a base charge ($) and declining block throughput charge ($/GJ).
		Tariff D applies to customers with requirements greater than 10 TJ pa at a single delivery point.	The charge for this service consists of a declining block MDQ charge ($/GJ of MDQ).
Brisbane[5]	Allgas Energy Distribution System	Tariff C applies to all other users.	The charge for this service comprises a base charge ($) and declining block throughput charge ($/GJ).
		Tariff D applies to customers with requirements greater than 10 TJ pa at a single delivery point.	The charge for this service consists of a demand charge ($/GJ of MHQ per day) and declining block MDQ charge ($/GJ of MDQ per day).
		Tariff V applies to customers with requirements less than 10 TJ pa at a single delivery point.	The charge for this service consists of a daily fixed charge ($) and declining block volume charge ($/GJ per day).

Retail Markets	Pipeline name	Service	Tariff Structure
Brisbane[5]	Envestra Distribution System	Tariff D applies to customers with requirements greater than 10 TJ pa at a single delivery point.	The charge for this service consists of a fixed charge ($) and declining block MDQ charge ($/GJ of MDQ).
		Tariff V applies to customers with requirements less than 10 TJ pa at a single delivery point.	The charge for this service consists of a daily fixed charge ($) and declining block volume charge ($/GJ per day).
Hobart[6]	Tasmanian Distribution System	n.a.	Fixed monthly charge for connection points ($) and throughput charge ($/GJ)

Sources:

1. Information obtained from the AGL, Access Arrangement for New South Wales Network, June 2005.
2. Information obtained from the Actew AGL, Access Arrangement for the Gas Distribution System in the ACT and Greater Queanbeyan, November 2004.
3. Information obtained from Multinet, Access Arrangement, 30 March 2007, SP AusNet, Gas Access Arrangement review 2008-2012, 2007 and Envestra, Access Arrangement Information for Envestra Victorian Distribution Systems, 30 March 2007.
4. Information obtained from the Envestra, Access Arrangement for South Australian Gas Distribution System, October 2006.
5. Information obtained Envestra, Access Arrangement for the Queensland Gas Distribution System, September 2005 and Allgas, Access Arrangement for the Queensland Network, 1 October 2005.
6. Information obtained from Powerco's website http://www.powerco.com.au/Project_description/default.htm

6. Risk management tools

The principal risk faced by retailers purchasing gas from the wholesale market under long term contracts is the risk that actual demand will deviate from contracted volumes on a daily basis (volume risk). Thus while retailers face some pricing risk at each price review this risk only arises every three to five years which is in stark contrast to volume risk which retailers are exposed to on a daily basis.[126] The majority of risk management tools that have emerged have therefore been designed to address the volume risk faced by buyers.

The term risk management tools is used in this context to describe both contractual provisions specified within a wholesale gas supply contract and other external arrangements which seek to minimise the risks faced by a retailer entering into long term gas supply contracts. In addition to these risk management tools, larger retailers with interests in a number of jurisdictions have sought to minimise their exposure to price and volume risk by holding a portfolio of gas supply contracts. A number of risk management tools have also been developed to enable buyers to minimise their exposure to transportation based volume risks.

The remainder of this section provides an overview of the risk management tools that are utilised by retailers.

6.1. Tools to manage the ex-plant price risk

Gas is predominantly sold under long term contracts and the price payable under these contracts is generally specified for an initial period with provision made for periodic price reviews over the contract life (ie, every three to five years). These price reviews enable the price to be re-negotiated to reflect current market conditions. Where the parties cannot reach agreement on the price at these price reviews then commercial arbitration provisions may be triggered.

From a retailer's perspective it will be exposed to the risk that the price of gas negotiated at each price review will increase above that which it can pass on to end users. Given the infrequent nature of these reviews no external risk management tools have been developed to ameliorate this pricing risk. However, retailers have been afforded some protection in this area by the inclusion of provisions within some contracts that require the price review or price arbitration to have regard to the current market conditions. Since current market conditions generally reflect the price of gas paid by other retailers and may also reflect the price of alternative fuels, these provisions to some extent reflect the ability of the retailer to pass that cost onto end users. Linking the price review provisions to the current market conditions may therefore afford the retailer some level of protection at each price review.

The benefit of such provisions can be seen in the following quote taken from an AGL media release announcing its new gas supply portfolio in December 2002.

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[126] Other buyers of gas (such as gas fired power generators or ammonium producers) may face price risk on a daily basis if demand for their product if it has little control over the price (ie, subject to electricity spot prices or world ammonium prices). To ameliorate this price risk buyers may be able to negotiate a price that is linked to the price of electricity or world ammonium prices see Kimber Consultants Pty Ltd, Australia's gas reform process and its effect on gas prices, June 1998, pg. 7.

> The arrangements contain price reset mechanisms that will ensure AGL maintains its competitive position in the market place.[127]

Holding an equity interest in the field supplying it with gas may also enable a retailer to offset the ex-plant prices it faces. Holding an equity interest in other gas fields may also mitigate price risk over the longer term, however, it must be recognised that prices under each contract are set on a periodic basis and thus the price review period for the gas supply contract held by the retailer may not align directly with the price review period for the contracts held through its upstream interests. Another important point to recognise in this context is that while holding an equity interest may mitigate the pricing risk faced by a buyer, the interest does expose the buyer to a range of physical risks the most significant of which being that the proven and probable reserve estimates that underpinned the acquisition price cannot be recovered.

6.2. Tools to manage gas supply volume risks

Volume risk arises because buyers are required to specify the annual contract quantities they will purchase in each year of the contract term at the commencement of the contract. The requirement to specify annual contract quantities reflects the desire of producers who face relatively low marginal costs of producing additional gas and thus have a strong interest in securing contracts for the sale of gas up to the production capacity of each field. Having to specify contract quantities in advance exposes retailers to the risk that their actual requirements will deviate from the forecast requirements both within a contract year and over the contract life.

For retailers, deviations within a contract year will flow from:

§ seasonal influences which affect the consumption of residential customers; and

§ other factors that influence the consumption of industrial customers including demand for the industrial customer's end product.

The seasonal influence on residential consumption is particularly pronounced in colder climates (ie, Victoria, South Australia, the Australian Capital Territory (see Box 6.2), Tasmania and parts of New South Wales) and thus retailers supplying these areas will be subject to higher winter peaks than retailers supplying more temperate locations (ie, Queensland).

Box 6.1: Seasonal influence on demand – Canberra

On 15 June 2006 the temperature in Canberra fell below the average for that time of year and the demand for gas on that day surpassed previous records reaching 68 TJ which was 23 TJ higher than the winter average and 10 TJ above the previous record. ActewAGL had insufficient gas to meet the increased demand and called on residents to voluntarily restrict their gas consumption. Residents responded to this voluntary restriction by reducing their demand by 15 per cent which gave ActewAGL time to replenish linepack.

Source: ActewAGL media release, Regular natural gas levels restored in the ACT and Queanbeyan, 16 June 2006.

127 AGL, AGL Announces New Gas Supply Portfolio, 18 December 2002.

The volatility of demand in Victoria can be seen by comparing the average daily withdrawals over the summer period with the average daily withdrawals over the winter period. According to VENCorp data over 2006 the average daily withdrawals over winter were 2.3 times higher than the withdrawals over the summer period. On the peak winter day (19 July 2006) withdrawals were 3 times higher than the summer average.[128] Given the magnitude of this variation a retailer operating in such a market would need to have risk management tools in place to ensure that peak demands can be met.

Deviations may also occur over the longer term if there are structural changes in the demand for gas by a retailer's customer base. These structural changes may include shifts toward alternative energy sources or increased competition which results in a reduction in customers.

The risk management tools that have emerged have therefore been designed to address the risk surrounding contracted quantities both within the year and over the contract life.

6.2.1. Managing volume risk within a contract year

Within a contract year a buyer will be exposed to the following volume related risks:

- the risk that actual demand over the year will be lower than the annual contract quantities specified in the contract; and
- the risk that its actual daily demand for gas will on any given day of the year exceed the average daily contracted quantities implied by the annual contract quantities.

6.2.1.1. Risk that actual demand will be lower than the annual contract quantities

To ameliorate the first of these risks, gas supply contracts typically contain take or pay provisions which require the buyer to pay for a percentage (eg, 80 per cent) of the annual contract quantities irrespective of whether they 'take' supply. Although a buyer would still be exposed to the risk that its actual demand over the year will be lower than the take or pay quantities it would be afforded some level of protection between the take or pay requirement and the annual contract requirement.

6.2.1.2. Risk that daily demand will exceed the average daily contract quantities

Contractual provisions and risk management tools have also been developed to address the risk surrounding daily demand requirements. The principal contractual provision referred to in this context is the swing factor. The swing factor enables a buyer to vary its daily demand over the year by taking more than the average daily contracted quantity on any one day subject to the cap imposed by the annual contract quantities being met. These provisions therefore accord the buyer with some flexibility to manage their daily gas supply requirements over the year as can be seen in Box 6.2.

Other risk management tools that may be used by buyers with interests in Victoria include entering into a contract for storage services with the Western Underground Storage facility at Iona, the LNG facility at Dandenong or purchasing gas on the spot market.

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[128] VENCorp, Prices and Withdrawals Data (2006).

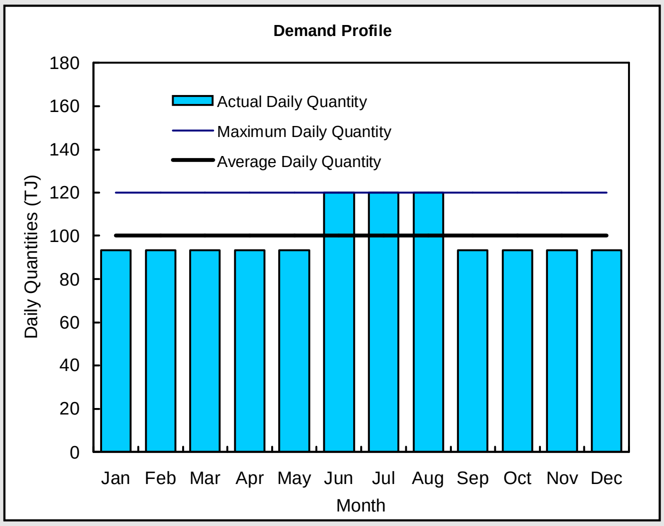
The storage services offered by the Western Underground Storage facility allow a buyer to store gas that it purchases during non-peak periods (ie, over summer) and access that gas during peak periods (ie, over winter). These storage services do not enable the buyer to take any more gas over the year than that implied by the annual contract quantities specified in the gas supply contract. However, the storage facilities do allow the buyer to store some of the gas it purchases over the summer months and to release that gas over the winter months such that the gas released exceeds the maximum daily quantities specified in the gas supply contract.

Box 6.2: Contractual provisions

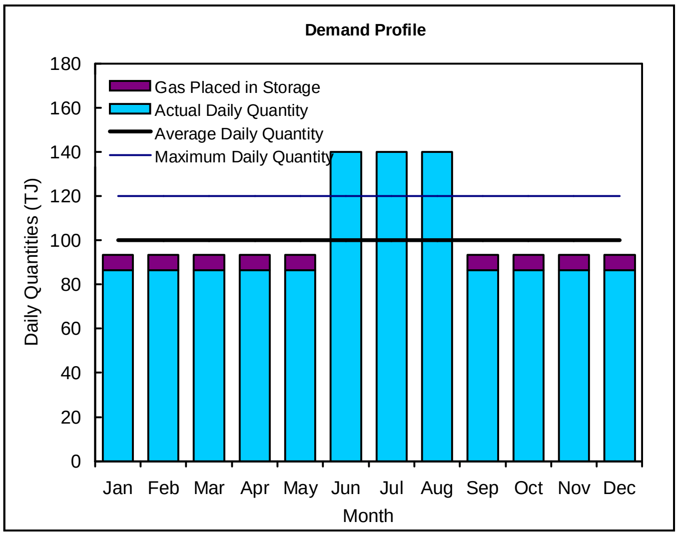
In this example it is assumed that:

- the annual contract quantities are 36.55 PJ per annum which implies an average daily quantity of 100 TJ (36.55 PJ ÷ 365 days); and
- the maximum daily quantities are specified as 120 TJ per day which translates to a swing factor of 120 per cent (maximum daily quantity ÷ average daily quantity = 120 TJ ÷ 100 TJ = 120%).

If demand over winter (June to August) exceeds the average daily quantity then the buyer may take up to 120 TJ per day over this 92 day period. If the maximum daily quantities are taken over this period then the buyer will purchase 11.05 PJ over this period leaving it with 26.5 PJ to take over the remainder of the year. Dividing this 26.5 PJ by the remaining days (273 days) implies that the buyer can only take 93 TJ per day over the remainder of the year. The profile of demand over the year can be seen in the following diagram.



Using the example set out in Box 6.2 this may be done by storing 7 TJ per day during the summer months and supplying just 86 TJ into the market. This additional 7 TJ per day would enable the buyer to release 140 TJ per day over the 92 day winter period rather than the 120 TJ provided for in the contract.



The spot market in Victoria provides another means by which a retailer with interests in Victoria may supplement its maximum daily quantities on a given day by purchasing gas at the spot price and paying any additional charges for breaching its AMDQ on the Principal Transmission System.

Managing these daily variations in demand is not costless and thus retailers with a volatile load profile (ie, as a consequence of being located in a colder climate) will face higher costs than those retailers with a smoother load profile.

6.2.2. Managing volume risk over the life of the contract

Having to specify the annual contract quantities that will be purchased over the life of the contract at the time the contract is entered into also exposes the buyer to the risk that its actual gas requirements will, over a prolonged period of the contract life, be lower or higher than the forecast annual contract quantities and the associated take or pay quantities. To ameliorate this risk some contracts contain provisions that enable the buyer to permanently decrease or increase their annual contract quantities within a specified band (ie, +/- 5 per cent of annual contract quantities) subject to the producer being given sufficient notice.

6.3. Swaps

Over the counter gas swaps are another risk management tool used by retailers. These swaps are typically agreed between retailers on a confidential basis for short periods of time and thus there is little public information on the utilisation of this risk management tool.

A survey recently undertaken by Firecone does provide some insight into the rationale for entering into swaps.[129] According to the results of this survey the majority of swaps were short term (ie, a few months) although there were some multi-year agreements. Participants in this survey noted they had used swaps for the following reasons:

- Outage or other interruptions in anticipated production;

[129] NCC and Firecone, Occasional Series – Gas Swaps, April 2006.

- Minimising pipeline transmission costs, taking into account high MDQ charges and low backhaul tariffs;
- Smoothing load, given inverse season variation in load shape between retailers at different locations; and
- Supporting entry into new markets, where the retailer does not have adequate existing supply arrangements.[130]

Firecone also noted that retailers had informed them that their "usual approach was to ensure that their retail position was supported by adequate contract cover".[131]

AGL and TRUenergy recently entered into a gas swap as part of their broader asset swap agreement involving the Torrens Island gas fired power station and the Hallet gas fired peaking plant.[132] This swap involved swapping both gas supply and transportation arrangements.

6.4. Portfolios of gas supply contracts

Retailers with interests in a number of jurisdictions may also seek to minimise their exposure to a particular basin (including the exposure to the price payable from that basin and the risk of any unanticipated reduction in gas supply from that source) and manage the volume risk surrounding their entire customer base by holding a portfolio of gas supply contracts with a number of producers.

The value of this diversification will depend on the risks associated with the security of gas supply from particular sources and the flexibility afforded by the portfolio which allows the retailer to optimise the take or pay levels and swing factors specified in each contract over its entire customer base.

AGL is one retailer that has adopted this risk minimisation strategy. AGL currently has retail interests in all but one of the capital cities in eastern Australia and has a portfolio of gas supply contracts with producers in the Cooper/Eromanga Basin, the Gippsland Basin, the Bowen/Surat Basin and Sydney Gas Company and gas transportation contracts on the Moomba to Sydney Pipeline, the Moomba to Adelaide Pipeline, the Victorian Principal Transmission System and the Eastern Gas Pipeline. In announcing the development of this portfolio of contracts AGL stated:

> It has always been AGL's stated objective to secure a diversified portfolio of gas supplies at competitive prices to minimise the risks associated with supply delivery and maximise the Company's ability to effectively compete in key Australian gas markets.[133]

In a recent presentation AGL's Managing Director and CEO, Paul Anthony, referred to its portfolio of contracts as providing AGL with considerable flexibility both in relation to

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130 NCC and Firecone, Occasional Series – Gas Swaps, April 2006, pg. 9.

131 NCC and Firecone, Occasional Series – Gas Swaps, April 2006, pg. 9

132 AGL, Media Release, 29 January 2007.

133 AGL, AGL Announces New Gas Supply Portfolio, 18 December 2002.

annual contract quantities, maximum daily quantities, take or pay provisions and delivery points.[134]

Origin has also referred to the flexibility that a portfolio of contracts has afforded it as can be seen in the following quote taken from a presentation made by Origin in May 2007:

> Origin procures gas to service its Retail operations from a variety of sources including:
> - Purchases from 3rd party suppliers;
> - Purchases from 3rd parties involved in joint ventures with Origin; and
> - Internal purchases from Origin production.
>
> These contracts have flexibility between the Annual Contract Quantity available and the Take-or-pay commitments.[135]

6.5. Tools to manage transportation volume risk

Retailers entering into contracts for firm forward transportation services will also face the risk that actual throughput on any one day will deviate from the reserved capacity. The manner by which this risk is managed will differ between pipelines operating at (or close to) capacity and pipelines that are underutilised.

For pipelines operating at (or close to) capacity a retailer will need to reserve capacity equivalent to its peak daily requirement to ensure that it is able to deliver the quantities required on a firm basis on any day of the year including peak periods. Since transportation charges are primarily capacity based, the buyer will be required to pay charges on the maximum daily quantities notwithstanding the fact that it may only transport those quantities for a limited time over the year. This is a costly option although the retailer may be able to offset some of these costs by trading their excess capacity with another buyer.

For an underutilised pipeline a retailer may be able to reserve a lower level of capacity on the pipeline and use as available services to supplement the firm transportation service to meet the peak requirements on any one day. Since the pipeline has excess capacity the likelihood of the 'as available' service being delayed in peak times would be relatively low and thus the retailer can place some reliance on this service when managing its daily transportation requirements. Using a combination of firm and as available services will result in lower transportation costs relative to the retailer that has reserved the same capacity requirements on a firm basis.

There are a number of other contractual provisions contained within gas transportation agreements which accord the retailer some flexibility in managing daily variations in demand including park and loan services, tolerance bands around daily nominations and authorised overruns. To meet these daily variations the pipeline operator will utilise linepack.[136, 137]

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[134] AGL, Presentation March 2007, pg. 17.

[135] Origin, Australia's leading fuel integrated generator retailer, US Roadshow, May 2007.

[136] Energy Retailers Association of Australia, An Australian Wholesale Gas Market– Its Justification, Framework and Governance, September 2004.

[137] Users are generally required to supply additional gas into the pipeline for the effective operation of the pipeline. This gas is termed linepack.

7. Retail

7.1. Overview of the operation of the retail market

For residential customers the retail market represents the last link of the gas supply chain. This segment of the supply chain has undergone substantial change over the last ten year which has principally been driven by:

- the separation of what were once vertically integrated transportation and retail monopolies into their natural monopoly components; and
- the introduction of full retail competition (FRC).

The introduction of FRC has been undertaken in a staged manner across the jurisdictions with larger consumers being the first to have the opportunity to choose their provider followed in some jurisdictions by smaller users. The timetable for the introduction of FRC has varied across each jurisdiction as can be seen in Table 7.1 below. In Tasmania, users of all sizes have been able to choose their provider since gas commenced flowing into the State.[138]

Table 7.1: Introduction of Full Retail Competition

Customer Size	ACT	NSW	Qld	SA	Vic
> 500 TJ		30/8/1996			1/10/1999
> 250 TJ					
> 100 TJ		1/7/1997	1/7/2001	1/4/1998	1/3/2000
> 10 TJ		1/7/1998		1/7/1999	1/9/2000
> 5 TJ					1/9/2001
> 1 TJ	1/10/1999	1/10/1999	1/7/2005		
all non-domestic				1/7/2000	
all remaining	1/1/2002	1/1/2002	1/7/2007	28/7/2004	1/10/2002

Sources: National Competition Council, 2005 NCP Assessment; ABARE Conference Paper 2002.3, "Economics of retail competition in Australia's natural gas industry", 12-15 February 2002; various regulator and market operator websites.

To facilitate FRC in the small user segment a number of jurisdictions have introduced market operators. These retail market operators have been accorded the role of processing customer transfers between retailers, providing technical support and overseeing the relevant market rules.

The market operators in eastern Australia include:

- the Gas Market Company (GMC) which is the retail market operator in New South Wales and the Australian Capital Territory;
- the Retail Energy Market Company (REMCo) which is the relevant market operator in South Australia; and

[138] National Competition Council, Assessment of Governments' Progress in Implementing the National Competition Policy and Related Reforms: 2005, October 2005, section 7.9.

- VENCorp which is the relevant retail market operator in Victoria and will take on the role of retail market operator in Queensland when FRC commences on 1 July 2007.[139]

All operators are non-profit organisations funded through the payment of fees (ie, registration fees, annual fees and fees applicable to retailers based on their customer numbers) by their members who include licensed distributors and retailers.

To facilitate competition in each jurisdiction, the retail market operators have four main functions to:[140]

- ensure that the daily gas usage is allocated to the correct retailer;
- maintain system security by certifying enough gas is in the network;
- enforce compliance with market rules; and
- manage customer switching.

These functions are carried out in accordance with the relevant market rules operating in that jurisdiction.

7.2. Relationship between retailer cost structures and market structure

For residential customers, retailers provide the interface between producers, transmission and distribution pipeline owners and are therefore responsible for securing the supply of gas and entering into the transportation arrangements required to deliver the gas to the customer's location.

To secure the supply of gas retailers will generally be required to enter into a long term contract with producer(s) which specifies the quantities it will purchase in each year of the contract life and establishes the minimum quantities that must be taken or paid for in each year. The take or pay provisions in effect operate as a minimum bill which must be met by a retailer even if actual demand is below the take or pay quantities. Viewed in this way the minimum bill operates as a fixed cost for retailers. In addition to paying the ex-plant price of gas, retailers will incur negotiation and contracting costs at both the commencement of the contract and at each price reset.

In those jurisdictions operating under a contract carriage model (ie, all jurisdictions excluding Victoria) a retailer will be required to enter into a contract for firm transmission services which specifies its capacity reservation and the delivery locations. Since transportation charges are predominantly capacity based, the transportation costs incurred by a retailer operating in these jurisdictions will be fixed. In addition to paying these transportation charges, retailers will incur negotiation and contracting costs. In contrast, a retailer operating in Victoria will not be required to reserve capacity on the Principal Transmission System and its charges will primarily be based on actual volumes transported (ie, variable cost).

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139 VENCorp media release, VENCorp to supply FRC services to Queensland, 17 July 2006.

140 REMCo website, http://www.remco.net.au/aboutRemco.aspx

A retailer will also be required to enter into transportation agreements with the owners of distribution systems in their respective retail markets. Since distribution charges in each jurisdiction are predominantly capacity based the distribution costs incurred by retailers will be largely fixed in nature.

In addition to the costs incurred in obtaining gas and transportation services, a retailer will also incur licensing costs, retail market fees payable to the relevant retail market operator, marketing costs and the costs associated with establishing a billing system.

According to estimates prepared by the Independent Pricing and Regulatory Tribunal (IPART) and Envestra the costs of acquiring gas and transporting that gas to the customer's location account for 90 per cent of the total cost paid by residential customers. Specifically, the study published by IPART found that:[141]

§ 30 per cent of a residential customer's total gas cost is accounted for by the ex-plant price of gas and the transportation of that gas to the city gate;

§ 60 per cent of a residential customer's total gas cost is accounted for by local distribution costs and metering charges;

§ 8 per cent of a residential customer's total gas cost is accounted for by the retailer's billing, marketing and customer support costs; and

§ 2 per cent of a residential customer's total gas cost reflects the retailer's net profit margin.

Envestra's estimates were published by the Productivity Commission in its Review of the Gas Access Regime.[142] According to these estimates:

§ 20 per cent of a residential customer's total gas cost is accounted for by the ex-plant price of gas and the transportation of that gas to the city gate;

§ 70 per cent of a residential customer's total gas cost is accounted for by local distribution costs and metering services; and

§ 10 per cent a residential customer's total gas cost reflects the retailer's costs and profit margin.

Given the relative magnitude of the ex-plant price of gas and the transportation charges and the predominantly fixed nature of these costs, one would expect that a retailer considering whether or not to enter a particular jurisdiction would only do so if they are able to obtain the scale necessary to spread the fixed costs. This scale may be achieved either through a customer base which comprises a large number of small customers or a small number of large customers. Where this scale cannot be achieved an incumbent may continue to supply the majority of the market notwithstanding the introduction of FRC.

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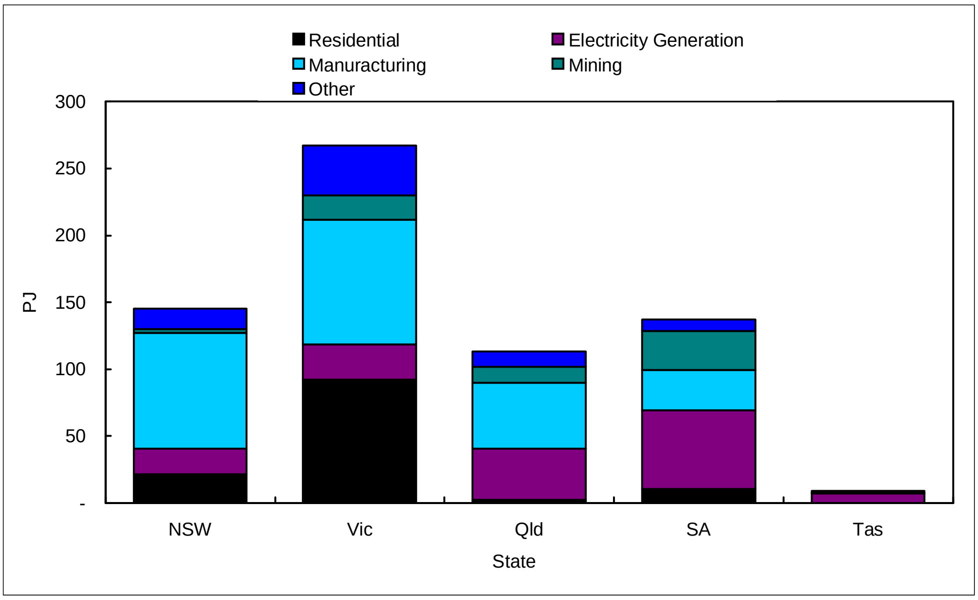
141 IPART, Final Report: Review of the Delivered Price of Natural Gas to Tariff Customers Served from the AGL Gas Network in New South Wales, February 2001, pg. 29.

142 Productivity Commission, Review of the Gas Access Regime, August 2004, pg. 46.

Examining ABARE's 2004-05 gas consumption estimates it is immediately apparent that the consumption of gas by end users varies significantly across the jurisdictions both in terms of the composition of users and the quantities of gas consumed (see Figure 7.1).

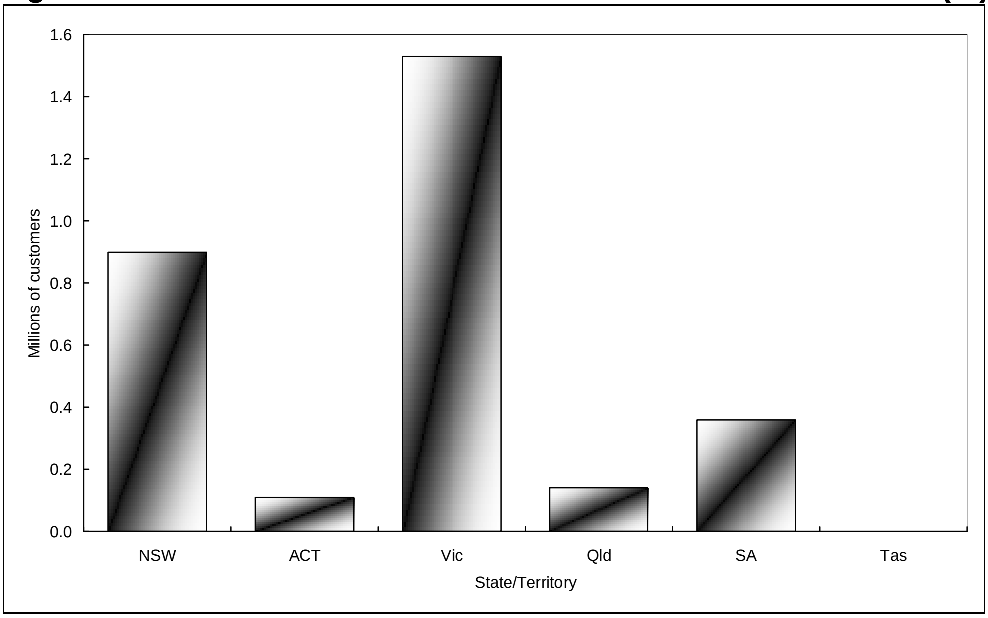
Figure 7.1: Composition of gas consumption 2004-05



Source: ABARE, Statistical Table F
Note: The New South Wales estimates include consumption in the Australian Capital Territory.

The number of residential customers in each state and territory in eastern Australia also varies markedly as can be seen in Figure 7.3.

Figure 7.2: Numbers of residential customers as at June 2006 (m)



Source: UBS, Australian Utilities Structure 2006.

Both the composition of demand in each jurisdiction and the number of customers in each jurisdiction will directly influence the scale which retailers can obtain within a particular jurisdiction and in turn will influence the number of retailers entering each jurisdiction and the extent of competition within each jurisdiction.

Based on the ABARE consumption data and UBS' estimate of residential customers one would expect that the size of the Victorian market coupled with the large number of residential and manufacturing customers would attract a greater number of retailers than Queensland, South Australia and Tasmania.

Although South Australia and New South Wales appear to consume similar quantities of gas (145 PJ in New South Wales versus 137 PJ in South Australia) the composition of demand is quite different with electricity generation and mining accounting for approximately 65 per cent of demand compared to 15 per cent in New South Wales. Since gas fired power generators and those in the mining industry typically enter into direct gas supply contracts with producers the remainder of the market in South Australia is substantially smaller than that in New South Wales (123 PJ in New South Wales versus 63 PJ in South Australia). Given this difference one would expect more retailers to enter the New South Wales market relative to South Australia.

The composition of demand in Queensland is quite similar to that in South Australia and thus one would expect a lower number of retailers to enter this market relative to the number entering the New South Wales and Victorian markets.

In Tasmania the demand for gas has primarily been driven by gas fired power generation with some incremental consumption by residential users. Although the size of the residential consumption base is expected to increase following the construction of the distribution system in Hobart, the relatively small size of the population in this area will place a limit on the overall size of this consumption base. The cost of switching to gas fuelled appliances will also mean that the transition to natural gas by residential customers will take some time and over this transitional period retail prices will be subject to the competitive constraint of existing fuels.

7.3. Market structure

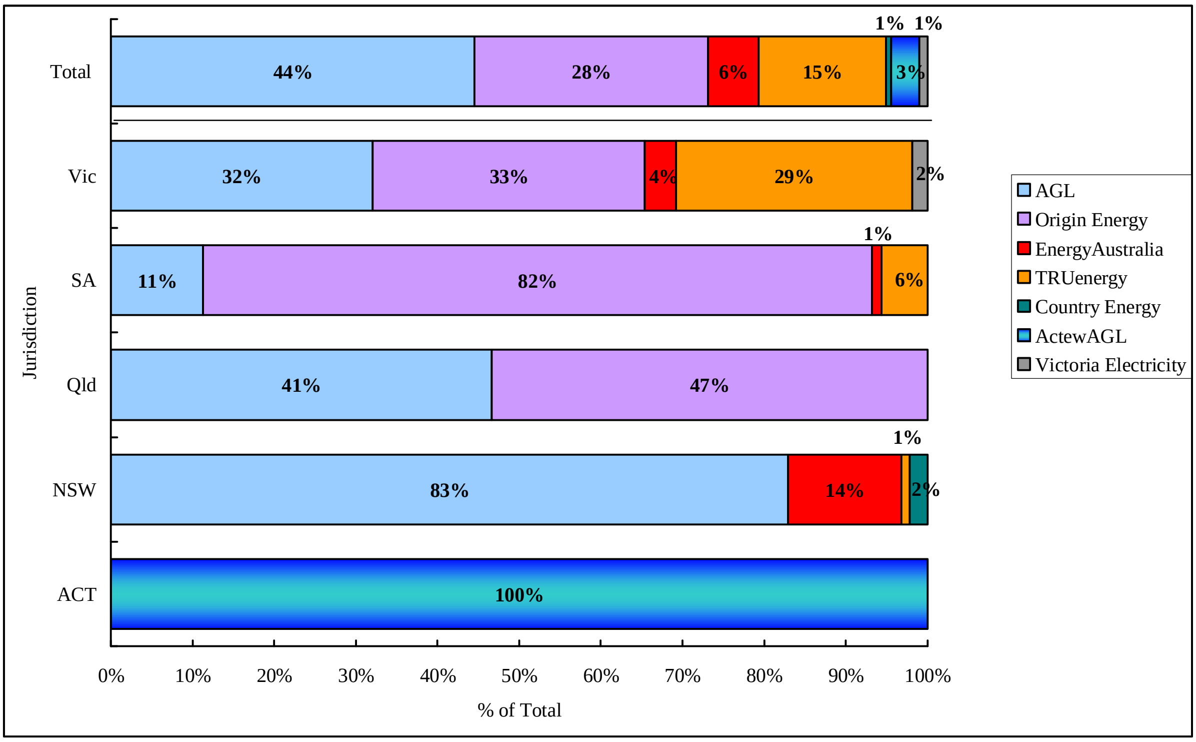
Table 6.1 sets out the number of customers supplied by retailers across each jurisdictions as at June 2006 and Figure 7.3 illustrates the relative market share of each retailer.

Table 7.2: Gas customers by jurisdiction and retailer as at June 2006 (m)

	ACT	NSW	Qld	SA	Vic	Total
AGL		0.78	0.07	0.04	0.51	**1.4**
Origin Energy			0.08	0.29	0.53	**0.9**
EnergyAustralia		0.13		0.004	0.06	**0.2**
TRUenergy		0.01		0.02	0.46	**0.5**
Country Energy		0.02				**0.0**
ActewAGL	0.11					**0.1**
Victoria Electricity					0.03	**0.0**
Total	**0.11**	**0.94**	**0.17**	**0.354**	**1.59**	**3.2**

Source: UBS, Australian Utilities Structure 2006 - updated for recent acquisitions. Note: numbers may not add up due to rounding

Figure 7.3: Retail market shares as at June 2006



Source: UBS, Australian Utilities Structure 2006 - updated for recent acquisitions

Examining Figure 7.3 it is immediately apparent that:

- AGL is the largest retailer in New South Wales and the Australian Capital Territory;
- Origin is the largest retailer in South Australia;
- Origin, AGL and TRUenergy have comparable market shares in Victoria;
- Origin and AGL have broadly similar market shares in Queensland; and
- AGL, Origin and TRUenergy accounted for 88 per cent of the retail market as at June 2006 with AGL being the largest retailer followed in descending order by Origin and TRUenergy.

Table 7.3: Licensed gas retailers in eastern Australia

Licensed Retailer	Licensed in more than 2 jurisdictions?	Licensed in Jurisdiction						Gvt. Owned?	Known gas supply contracts[3]	Other gas interests
		SA	Vic	NSW[1]	ACT	Qld[2]	Tas			
AGL (including Sun Gas)	ü	03/01	09/99*	07/97	JV with Actew	19/04	n.a.	û	Cooper/Eromanga, Bass Strait, Camden, Fairview, Spring Gully, Argyle, Lauren and Berwyndale South	Upstream interests Sydney Basin, Berwyndale South, Morambah and Argyle, Lauren and Berwyndale South (via QGC). Gas fired power generation interests Torrens Island.
ActewAGL (50/50 JV)	û	n.a.	n.a.	05/97	06/01	n.a.	n.a.	Actew ACT Gvt owned		
Origin Energy	ü	09/98	12/97	04/97~	06/01^	07/04#	n.a.	û	Cooper/Eromanga, Bass Strait, Spring Gully, Mungi, Yolla Geographe/Thylacine	Upstream interests Fairview, Spring Gully, Peat, Roma, Argyle, Lauren, Dennison Trough, Otway, BassGas and Cooper/Eromanga. Two gas fired power generation assets in South Australia and two assets in Queensland.
TRUenergy	ü	04/98	12/97	01/98	08/05	n.a.	n.a.	û	Bass Strait, Casino and Geographe/ Thylacine	Owner of the WUGS and Iona gas processing facility. Gas fired power generation interest Hallett.
EnergyAustralia	ü in JV	n.a.	n.a.	05/97	07/03	n.a.	n.a.	NSW Gvt	Alinta EATM	n.a.
Energy Australia Pty Ltd and Ipower Pty Ltd - trading as EA IP Retail Partnership (50/50 JV)[9]		06/05	06/05	n.a.	n.a.	n.a.	n.a.	EANSW Gvt	Minerva	International Power has gas fired power generation interests in South Australia.
Santos Direct Pty Ltd	ü	08/06	09/04	02/07	n.a.	n.a.	n.a.	û	Minerva	Upstream interests in Cooper/Eromanga, Minerva, Casino.
BHP Billiton Petroleum Pty Ltd	û	n.a.	08/00	04/97^^	n.a.	n.a.	n.a.	û	Bass Strait	Upstream interests in Minerva and Bass Strait
Esso Australia Resources Pty Ltd	û	n.a.	12/97	01/98	n.a.	n.a.	n.a.	û	Bass Strait	Upstream interests in Bass Strait

Licensed Retailer	Licensed in more than 2 jurisdictions?	Licensed in Jurisdiction: SA	Vic	NSW[1]	ACT	Qld[2]	Tas	Gvt. Owned?	Known gas supply contracts[3]	Other gas interests
Australian Power and Gas Pty Ltd	ü	n.a.	11/06	02/07	n.a.	01/07	n.a.	û	n.a.	n.a.
Jackgreen (International) Pty Limited	ü	09/06	n.a.	10/05	05/07	n.a.	n.a.	û	n.a.	n.a.
Aurora	û	n.a.	n.a.	n.a.	n.a.	n.a.	02/04	Tas Gvt	Bass Strait	n.a.
Country Energy	û	n.a.	n.a.	07/01	02/03	n.a.	n.a.	û	Bass Strait via Alinta EATM	n.a.
Dalby Town Council	û	n.a.	n.a.	n.a.	n.a.	06/04	n.a.	Qld Gvt	n.a.	n.a.
Integral	û	n.a.	n.a.	02/05	n.a.	n.a.	n.a.	NSW Gvt	n.a.	n.a.
Option One Pty Ltd	û	n.a.	n.a.	n.a.	n.a.	n.a.	08/03	û	Bass Strait	n.a.
Red Energy Pty Limited	û	n.a.	11/06	n.a.	n.a.	n.a.	n.a.	NSW/Vic Gvt	n.a.	n.a.
Roma Town Council	û	n.a.	n.a.	n.a.	n.a.	05/04	n.a.	Qld Gvt	n.a.	n.a.
South Australia Electricity Pty Ltd	û	09/05	n.a.	n.a.	n.a.	n.a.	n.a.	û	n.a.	n.a.
Victoria Electricity Pty Ltd	û	n.a.	12/04	n.a.	n.a.	n.a.	n.a.	û	n.a.	n.a.
Total	**7**	**7**	**10**	**12**	**6**	**5**	**2**			

Notes:
1. In NSW Westfarmers Kleenheat Gas Pty Ltd is licensed although it is an LPG supplier.
2. In Qld Westfarmers Kleenheat Gas Pty Ltd and Elgas is licensed although it is an LPG supplier.
3. Information obtained from Core Collaborative, Australian Gas Sector Outlook, Appendix A.
4. Sun Gas license date, AGL was granted in 08/00.
5. Origin Energy LPG Limited only Origin entity licensed.
6. Licensed issued to Sun Retail.
7. General retail license, area licenses were granted the following year.
8. Granted to BHP Billiton Petroleum (Bass Strait) in 02/99.
9. On 25 May 2007 EnergyAustralia announced that International Power had exercised a call option to acquire EnergyAustralia's 50 per cent interest in the joint venture. It is expected that this acquisition will be completed by August 2007.

Sources: Company, Regulators and Government department websites

7.3.1. Retail license holders

Table 6.2 sets out the licensed retailers operating in eastern Australia and provides an overview of the ownership structure, the gas supply contracts that the licensed retailer has in place and details of any upstream interests the retailer has.

Examining the information contained in this table a number of observations can be made.

First, as predicted in section 7.2 there are a greater number of retailers operating in New South Wales and Victoria than in South Australia, Queensland, the Australian Capital Territory and Tasmania.

Second, of the twenty entities that have obtained licenses across the jurisdictions seven are licensed to retail gas in more than two jurisdictions and 14 are licensed to operate in more than one jurisdiction.[143]

Another interesting point to note from this table is that the larger retailers, AGL, Origin and TRUenergy all operate across more than two jurisdictions. These three retailers also hold a portfolio of gas supply contracts over which they can balance their retail requirements, have upstream interests in gas production and/or processing facilities and have interests in gas fired power generation assets.

Finally, while there is some level of government ownership this has largely arisen as a result of government owned electricity retailers becoming dual fuel retailers (ie, EnergyAustralia, Integral and Aurora).

7.4. Retail markets in each capital city

7.4.1. Adelaide

Retailers' options for supply and delivery of gas

Until 2004 the only source of gas for retailers in Adelaide was the Cooper/Eromanga Basin, which was transported to Adelaide via the Moomba to Adelaide Pipeline. Following the construction of the SEA Gas pipeline, retailers can now source their gas from Victoria. However, this option may be limited somewhat by the firm forward haulage capacity constraints that exist on this pipeline unless the retailer is able to purchase transportation capacity from an existing user. Retailers in Adelaide may also be able to acquire gas on a delivered basis from aggregators.

Given these options a retailer operating in Adelaide may either:

- enter into a gas supply contract with producers in the Cooper/Eromanga Basin and a transportation contract with the owners of the Moomba to Adelaide Pipeline;

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143 South Australia Electricity Pty Ltd. is a subsidiary of Victoria Electricity Pty Ltd.

- enter into a gas supply contract with producers in Victoria and a transportation contract with the owners of the SEA Gas pipeline if firm capacity is available or alternatively enter into an arrangement with an existing user willing to trade capacity; [144] or
- enter into a delivered contract with an aggregator with gas delivered to the city gates of Adelaide.

A retailer operating in Adelaide will also need to enter into arrangements to transport gas on the South Australian distribution system and pay market participant fees to REMCo.

Due to the colder conditions experienced in Adelaide over the winter months residential consumption can be relatively peaky over winter. Retailers supplying Adelaide therefore need to consider the extent to which they reserve firm transportation capacity up to the maximum daily quantity they expect to transport over the winter period or to utilise a combination of both firm and as available services. This will depend on the extent to which the transmission pipeline utilised by the retailer is operating at, or close to capacity (see section 6.5).

In the case of the Moomba to Adelaide Pipeline which currently has excess capacity a retailer could enter into a firm transportation contract for its average daily requirements and utilise as available services to supplement these quantities over the winter months. In contrast, a retailer using the SEA Gas pipeline, which is almost fully contracted on a firm basis, would need to obtain access to firm transportation services up to the peak winter maximum daily requirement to ensure that gas can be supplied on those peak days. A retailer may also incur daily variance charges, imbalance charges or overrun charges for variations in demand over the winter period. Retailers may also rely on park and loan services, tolerance bands around daily nominations and authorised overruns to supplement their transportation requirements over winter. The availability of these services will, however, depend on whether there is sufficient pipeline capacity available on that day.

Full Retail Contestability

FRC for users with annual consumption greater than 100 TJ was introduced in South Australia in 1998. This was progressively extended to smaller consumers with the final stage of FRC introduced on 28 July 2004. Since the introduction of FRC an additional seven players have entered the market including:

- AGL;
- EnergyAustralia International Power Retail Partnership;[145]
- Jackgreen;
- Santos Direct;

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[144] If gas is purchased from the Bass or Gippsland basins then the retailer will also need to become a market participant in Victoria and obtain an AMDQ allowance which enables it to transport gas through the Principal Transmission System.

[145] On 25 May 2007 EnergyAustralia announced that International Power had exercised a call option to acquire EnergyAustralia's 50 per cent interest in the joint venture. It is expected that this acquisition will be completed by August 2007.

- South Australia Electricity; and
- TRUenergy.

Momentum Energy has also recently applied for a gas retail license from ESCOSA.[146]

Apart from Santos Direct all of the aforementioned retailers are currently retailing to residential customers.

Customer transfer data indicates that customers have increasingly been taking advantage of FRC since its introduction.[147] Notwithstanding this switching, Origin, as the incumbent, still supplied a greater proportion of the market as at June 2006 (87 per cent) relative to other licensed retailers (ie, AGL - 12 per cent).[148]

It is worth noting in this context that Origin has upstream interests in both the Otway and Cooper/Eromanga basins and thus it may be viewed as having an advantage over retailers that do not have similar interests in the market. Until recently Origin also held a 17 per cent interest in Envestra (the owner of the Adelaide distribution system) and a one third share of the SEA Gas pipeline which may have also been viewed as providing Origin with a competitive advantage. These interests have recently been divested and thus any perceived advantage arising from this interest no longer exists.

7.4.2. Melbourne

Retailers' options for supply and delivery of gas

Retailers in Melbourne currently have the choice of obtaining gas from producers in the Gippsland, Bass, Otway and Cooper/Eromanga basins (via the Moomba to Sydney Pipeline and the Interconnect) and may trade imbalances on the Victorian spot market. Retailers may also be able to purchase gas from an aggregator such as Alinta EATM. To transport gas along the Principal Transmission System retailers will also need to become a market participant and enter into a gas transportation deed with VENCorp to receive an AMDQ allocation. A retailer operating in Melbourne will also need to have arrangements in place to transport gas on the relevant distribution system (Stratus Network Systems, Multinet Gas Systems, Westar Energy Systems) and pay market participant fees to VENCorp.

Due to the pronounced seasonal influence on residential consumption in Victoria, retailers in Victoria will also need to ensure that they have access to sufficient quantities of gas to meet the peak demand requirements of residential customers. This may be achieved by:

- entering into a gas supply contract that enables the buyer to take higher than average daily quantities over the winter period (ie, the contract specifies a high swing factor); and/or

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146 Momentum Energy, Application form for the issue of a license by the Essential Services Commission of SA under the Gas Act 1997, 11 April 2007.

147 Department of Transport, Energy and Infrastructure website, http://www.energy.sa.gov.au/pages/conventional/gas_reform/gasmarketreform.htm:sectID=2&tempID=1

148 UBS, Australian utilities structure 2006.

- entering into contractual arrangements for storage ie, the Western Underground Storage System or the LNG Storage Facility; and/or
- purchasing gas on the spot market.

A retailer's choice between these alternatives will depend on the relative costs of entering into a contract with a high swing factor versus the cost of gas storage versus paying the spot price which peaks over the winter period.

Full Retail Contestability

FRC was introduced in 1999, when retail licenses were issued and was progressively rolled out to smaller customers such that by October 2002 all users could choose between alternative retailers. The current list of licensed retailers in Victoria includes:

- AGL;
- Australian Power & Gas;
- BHP Petroleum;
- EnergyAustralia International Power Retail Partnership; [149]
- Esso.
- Origin;
- Red Energy;
- Santos Direct;
- TRUenergy; and
- Victoria Electricity.

Apart from Esso, BHP Petroleum and Santos Direct each of these retailers market their services to residential customers.[150]

The incumbents in this market include TRUenergy, AGL and Origin each of which acquired one of the three geographic retail businesses created through the vertical separation of Gascor (formerly Gas and Fuel Corporation of Victoria). These three retailers have broadly similar market shares and as at June 2006 Origin's market share was approximately 33 per cent while AGL's and TRUenergy's market shares were 32 per cent and 29 per cent respectively.[151]

Of the list of licensed retailers, Origin, Esso, Santos and BHP have upstream interests in the Victorian basins and thus may be viewed as having some competitive advantage over newer retailers with no such interests.

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[149] On 25 May 2007 EnergyAustralia announced that International Power had exercised a call option to acquire EnergyAustralia's 50 per cent interest in the joint venture. It is expected that this acquisition will be completed by August 2007.

[150] Esso and BHP Billiton sell their share directly to large users in NSW and Santos direct sells into the spot market from its portion of the Minerva field (Core Collaborative, 2020 Gas Outlook, pp. A9-13).

[151] UBS, Australian utilities structure 2006.

7.4.3. Sydney

Retailers' options for supply and delivery of gas

Until 2000, the option for supply into Sydney was limited to the Cooper/Eromanga Basin transported via the Moomba to Sydney Pipeline. Following the construction of the Interconnect and the Eastern Gas Pipeline, the options for supply have expanded to include gas produced in Victoria. The option to purchase gas from Victoria may be limited to some extent if there are firm capacity constraints on the Eastern Gas Pipeline. The development of coal seam methane fields in Camden by Sydney Gas has also increased the options although all of the quantities produced in this field are currently contracted to AGL.[152] Retailers in Sydney may also be able to acquire gas on a delivered basis from an aggregator such as Alinta EATM.

Given these options a retailer operating in Sydney may either:

- enter into a gas supply contract with producers in the Cooper/Eromanga Basin and a transportation contract with the owners of the Moomba to Sydney Pipeline;
- enter into a gas supply contract with producers in Victoria and a transportation contract with either the owners of the Interconnect and the Moomba to Sydney Pipeline or the owners of the Eastern Gas Pipeline if firm capacity is available (if capacity is not available the retailer may be able to enter into an arrangement with an existing user willing to trade capacity);[153] or
- enter into a delivered contract with an aggregator.

A retailer operating in Sydney will also need to have arrangements in place to transport gas on the New South Wales distribution system and pay market participant fees to GMC.

Residential consumption in Sydney is also susceptible to the influence of colder conditions over winter although this influence is less pronounced than in Melbourne. For a retailer supplying residents in Sydney faced with peaky winter requirements consideration would have to be given to how much firm transportation capacity should be reserved on the transmission pipeline used to transport the gas to Sydney. This decision will depend on the extent to which the transmission pipeline utilised by the retailer is operating at, or close to capacity (see section 6.5).

For instance, the Moomba to Sydney Pipeline has excess capacity and thus a retailer could reserve firm capacity for its average daily requirements and utilise an as available service over the winter months to supplement these quantities. In contrast, a retailer using the Eastern Gas Pipeline, which is operating close to capacity, would need to reserve firm transportation services up to the peak winter maximum daily requirement to ensure that gas

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[152] Sydney Gas, Annual Report 2006, pg. 65
"Under the GSA III Term Sheet agreed, all gas production from the Camden Gas Project joint venture, up to a total annual contract quantity of 14.5 PJ per annum of which the Company's share is 50%, is to be sold to AGL Wholesale Gas Limited (ACN 072 948 504). Any excess amount may be purchased at the option of the buyer."

[153] If gas is purchased from the Bass or Otway basins then the retailer will also need to become a market participant in Victoria and obtain an AMDQ allowance which enables it to transport gas through the Principal Transmission System.

can be supplied on those peak days. A retailer may also incur daily variance charges, imbalance charges or overrun charges variations in demand over the winter period retailers may also rely on park and loan services, tolerance bands around daily nominations and authorised overruns to supplement their transportation requirements over winter. The availability of these services will, however, depend on whether there is sufficient pipeline capacity available on that day.

Full Retail Contestability

FRC was introduced in 2002 and there are now 13 licensed retailers in New South Wales including:

- AGL;
- ActewAGL;
- Australian Power and Gas;
- BHP Billiton Petroleum;
- Country Energy;
- EnergyAustralia;
- Esso;
- Integral;
- Jackgreen;
- Origin;
- TRUenergy; and
- Santos Direct.

Apart from Esso, BHP Petroleum and Santos Direct each of these retailers market their services to residential customers.[154]

In the Sydney retail market AGL is the incumbent and continues to supply the majority of the market accounting for 83 per cent of the market as at June 2006. The other significant retailer in this market is EnergyAustralia which accounted for 12 per cent of the market.[155]

Until mid-2006 AGL had interests in the gas distribution system in Sydney, a 30 per cent interest in the Moomba to Sydney Pipeline and the Interconnect and a 50 per cent joint venture interest in the Sydney Gas Company. Each of these interests may have been viewed as according AGL a competitive advantage over other retailers. However, following the divestment of its interests in the distribution and transportation systems any perceived advantage arising from these transportation interests no longer exist. AGL continues to hold its interests in the Sydney Gas Company and thus it will continue to have access to a

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[154] Esso and BHP Billiton sell their share directly to large users in NSW and Santos direct sells into the spot market from its portion of the Minerva field (Core Collaborative, 2020 Gas Outlook, pp. A9-13).

[155] UBS, Australian Utilities Structure 2006.

proximately located supply of coal seam methane which may give it some advantage within the retail market. Retailers in Brisbane may also be able to acquire gas on a delivered basis from an aggregator.

At the end of April 2007 there were 1,161,755 metered customers administrated by the GMC across New South Wales and the Australian Capital Territory. According to GMC data there were 6,022 customer transfers in April 2007 which was the highest transfer rate since going live.[156]

7.4.4. Brisbane

Retailers' options for supply and delivery of gas

A retailer's option for the supply of gas into Brisbane includes gas produced in Ballera (transported via the South West Queensland pipeline and the Roma to Brisbane Pipeline) or coal seam methane or conventional natural gas produced in the fields in the Bowen/Surat and Clarence-Moreton basins (transported via the Roma to Brisbane Pipeline). A retailer's choice between conventional natural gas and coal seam methane will, as discussed previously, depend on the physical characteristics of coal seam methane relative to the retailer's demand requirements. Another issue facing retailers in Brisbane is that the Roma to Brisbane Pipeline is operating at capacity and thus any new entrant or expansion in demand will require a retailer to either contribute to the expansion of the pipeline or purchase capacity from an existing user of the pipeline.

Given these options a retailer operating in Brisbane may either:

§ enter into a gas supply contract with producers in the Cooper/Eromanga Basin and a transportation contract with the owners of the South West Queensland Pipeline and the Roma to Brisbane Pipeline if capacity is available or alternatively enter into an arrangement with an existing user willing to trade capacity;

§ enter into a gas supply contract with producers in Bowen/Surat/Clarence-Moreton basins and a transportation contract with the owners of the Roma to Brisbane Pipeline if capacity is available or alternatively enter into an arrangement with an existing user willing to trade capacity;[157] or

§ enter into a delivered contract with an aggregator.

A retailer operating in Brisbane will also need to have arrangements in place to transport gas on either the Allgas or Envestra distribution systems depending and pay market participant fees to VENCorp.

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156 GMC website, http://www.gasmarketco.com.au/grids/gmc_template_c.asp?id=575&area=96

157 If gas is purchased from the Bass or Otway basins then the retailer will also need to become a market participant in Victoria and obtain an AMDQ allowance which enables it to transport gas through the Principal Transmission System.

Full Retail Contestability

Both Sun Gas and Origin Energy are the only two retailers' currently selling natural gas in Brisbane.[158] In anticipation of FRC, the Queensland Government recently sold Sun Gas to AGL (via the sale of its interest in the retail arms of Energex). With FRC due to commence on 1 July 2007 a retail license has also been issued to Australian Power and Gas.

Both AGL and Origin have upstream interests in the production of coal seam methane in Queensland and Origin also has upstream interests in the Ballera field. These interests may be viewed as according the two a competitive advantage over other retailers that do not have similar interests in the market.

7.4.5. Canberra

Retailers' options for supply and delivery of gas

Until 2002, the only option for supply into Canberra was gas supplied from the Cooper/Eromanga Basin via the Moomba to Sydney Pipeline. Following the construction of the Eastern Gas Pipeline, the options for supply have expanded such that retailers in Canberra can now purchase their gas requirements from Victoria although this option may be limited to some extent if there are firm capacity constraints on the Eastern Gas Pipeline. Retailers in Canberra may also be able to acquire gas on a delivered basis from an aggregator such as Alinta EATM.

Given these options a retailer operating in Canberra may either:

- enter into a gas supply contract with producers in the Cooper/Eromanga Basin and a transportation contract with the owners of the Moomba to Sydney Pipeline;
- enter into a gas supply contract with producers in Victoria and a transportation contract with either the owners of the Interconnect and the Moomba to Sydney Pipeline or the owners of the Eastern Gas Pipeline if capacity is available (if capacity is not available the retailer may be able to enter into an arrangement with an existing user willing to trade capacity);[159] or
- enter into a delivered contract with an aggregator.

A retailer operating in Canberra will also need to have arrangements in place to transport gas on the ActewAGL system for distribution services and pay market participant fees to GMC.

Since residential consumption in Canberra peaks over the winter period, retailers supplying Canberra will need to consider the extent to which they reserve firm transportation capacity up to the maximum daily quantity they expect to transport over the winter period or to utilise a combination of both firm and as available services. This will depend on the extent to which the transmission pipeline utilised by the retailer is operating at, or close to capacity (see

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[158] Both the Dalby Town Council and Roma Town Council have retail licenses. However, these are used to supply residents in Dalby and Roma.

[159] If gas is purchased from the Bass or Otway basins then the retailer will also need to become a market participant in Victoria and obtain an AMDQ allowance which enables it to transport gas through the Principal Transmission System.

section 6.5). A retailer may also incur daily variance charges, imbalance charges or overrun charges variations in demand over the winter period retailers may also rely on park and loan services, tolerance bands around daily nominations and authorised overruns to supplement their transportation requirements over winter. The availability of these services will, however, depend on whether there is sufficient pipeline capacity available on that day.

Full Retail Contestability

FRC was introduced in Canberra on 1 July 2002 and there are now five licensed retailers in Canberra including.

- ActewAGL;
- Country Energy;
- EnergyAustralia;
- Jackgreen; and
- TRUenergy.

All of these entities currently retail to residential customers.

Prior to the introduction of FRC, ActewAGL was the sole retailer of gas and thus it may be viewed as the incumbent. This incumbent position has been maintained and as at June 2006 ActewAGL had close to a 100 per cent market share.[160]

ActewAGL is a joint venture partnership with 50 per cent of the partnership held by the government owned Actew Corporation and the remaining 50 per cent currently held by AGL. Actew also has a 50 per cent interest in the distribution system in Canberra with the remaining 50 per cent currently owned by Alinta (if the Singapore Power International Pty Ltd /Babcock & Brown offer is accepted Singapore Power International Pty Ltd will take over Alinta's interest in the distribution system).

7.4.6. Hobart

Retailers' options for supply and delivery of gas

The development of both the Tasmanian Gas Pipeline and the Hobart distribution system has only recently been completed and thus the retail supply of gas in Hobart is in its infancy. Given its proximity to the Victorian producers, retailers in Tasmania have the choice of purchasing gas from the Gippsland, Bass and Otway basins. The interconnection provided by the Interconnect also means that supply may be obtained from the Cooper/Eromanga Basin, however, the commercial viability of this choice will depend on the significant costs that would be incurred in transporting the gas to Longford. Retailers in Hobart may also be able to acquire gas on a delivered basis from an aggregator such as Alinta EATM.

Given these options a retailer operating in Hobart may either:

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[160] UBS, Australian utilities structure 2006.

- enter into a gas supply contract with producers in Victoria and a transportation contract with the owners of the Tasmanian Gas Pipeline;[161]
- enter into a gas supply contract with producers in the Cooper/Eromanga Basin and a transportation contract with the owners of the Moomba to Sydney Pipeline, the Interconnect and become a market participant in Victoria to enable gas to be transported from the Interconnect to Longford via the Principal Transmission System; or
- enter into a delivered contract with an aggregator.

A retailer operating in Hobart will also need to have arrangements in place to transport gas on the Hobart distribution system.

One would expect that the colder conditions experienced in Hobart over the winter months will cause residential consumption to peak over the winter months. Retailers supplying Hobart will therefore need to consider the extent to which they reserve firm transportation capacity up to the maximum daily quantity they expect to transport over the winter period or to utilise a combination of both firm and as available services. Since there is sufficient capacity on the Tasmanian Gas Pipeline at present it is likely that retailers would simply contract for their average daily requirements and utilise as available transportation services for any additional requirements over the winter period. A retailer may also incur daily variance charges, imbalance charges or overrun charges variations in demand over the winter period retailers may also rely on park and loan services, tolerance bands around daily nominations and authorised overruns to supplement their transportation requirements over winter.

Full Retail Contestability

There are currently two retailers that are licensed to operate in Tasmania, Option One and Aurora. Option One (a subsidiary of the New Zealand Company Powerco) was responsible for constructing the distribution system and is currently only retailing to non-residential customers. Aurora is the Tasmanian government owned incumbent provider of electricity and is retailing to residential customers.

According to data contained in Aurora's annual report, an estimated 38,500 customers will have access to the gas system in Tasmania.[162]

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161 If gas is purchased from the Bass or Otway basins then the retailer will also need to become a market participant in Victoria and obtain an AMDQ allowance which enables it to transport gas through the Principal Transmission System.

162 Stated connections after distribution expansion program in April 2007, Aurora, 2006 Annual Report.

8. Recent reviews of the gas market

Over the period 1999 to 2004 the production, transmission and distribution segments of the gas supply chain have been the subject of a number of reviews including those undertaken by:

- the Upstream Industry Working Group which examined upstream issues influencing growth (including joint marketing, acreage management and third party access to production facilities), the diversity and level of competition in downstream markets;[163]
- an independent review body chaired by Warwick R. Parer, which was commissioned by the Council of Australian Governments to examine the strategic directions for energy market reform including the governance and regulatory reforms required across the upstream and transportation segments of the gas and electricity markets (Parer Review);[164]
- ABARE, which was engaged by the Australian Gas Association to consider what reforms and conditions would be required to develop a competitive market for gas in Australia over the medium term;[165] and
- the Productivity Commission, which at the request of the Commonwealth Treasurer undertook an inquiry into the operation of the Gas Code.[166]

Drawing on the recommendations and findings of each of these reviews, the Ministerial Council on Energy (MCE) on 19 May 2004 announced an expanded gas work program that was designed to increase the pace of reform and facilitate the development of a reliable, competitive and secure natural gas market.[167] The expanded work program included three discrete work streams namely:

- the upstream gas work stream, which was established to review the upstream issues identified in the Parer Review; and
- the gas market development work stream, which was accorded responsibility for establishing the principles and design concepts for the future development of gas market and examining options to encourage new market entrants and promote efficient investment in infrastructure; and
- the gas infrastructure work stream, which was established to examine the Productivity Commission's recommendations in relation to the regulation of pipelines under the Gas Code and the level of investment in gas infrastructure.

The remainder of this section provides a summary of the progress that has been made in each of these areas.

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[163] http://www.treasury.gov.au/documents/177/HTML/docshell.asp?URL=ch7.asp

[164] W. Parer, Towards a Truly National and Efficient Energy Market, 20 December 2002.

[165] ABARE, Australian Gas Markets Moving Toward Maturity, December 2003.

[166] Productivity Commission, Review of the Gas Access Regime, August 2004.

[167] MCE, Reform of Energy Markets Expanded Gas Program, 19 May 2004.

8.1. Upstream gas work stream

Amongst other things, the Parer Review examined the factors that would need to be addressed at the upstream level to facilitate competition in this segment of the gas supply chain. The Parer Review concluded that there were three specific issues that should be addressed and proposed the following solutions:[168]

- separate marketing of gas should be actively facilitated as current contracts expire;
- Governments should give more consideration to promoting competition in gas markets when awarding exploration leases; and
- access by independent producers to upstream facilities should be considered further.

The Ministerial Council on Mineral Petroleum and Resources (MCMPR) was accorded the role of reviewing the upstream issues identified in the Parer Review. At the completion of this review the MCMPR concluded:[169]

- that it was unable to support the recommendations made in the Parer Review for mandatory notification of all future joint marketing arrangements or that the *Trade Practices Act 1974* be amended to preclude jurisdictions from exempting the application of section 45 to joint marketing of natural gas;
- that that there was no "systemic problem concerning exploration effort in production licence areas" and thus no change was necessary; and
- that a review of the industry's upstream third party access principles should be undertaken.

The MCE endorsed the MCMPR's conclusion on these issues in December 2004.[170]

Upstream issues as they relate to securing domestic supply are currently being considered by a joint working group on natural gas supply (JWG). The JWG was established in September 2006 by the MCMPR and the MCE to consider issues relating to the domestic demand and supply balance for gas, barriers to domestic gas supply and strategies to ensure availability of competitively priced gas, the risks associated with major inter-regional projects and policies that would facilitate the development of natural gas resources for export and long term domestic requirements.[171]

8.2. Gas market development work stream

The gas market development work stream was charged with the task of examining options for the future development of the gas market. To assist this process, the MCE in conjunction with industry participants, developed five overarching principles which are to guide any

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[168] W. Parer, Towards a Truly National and Efficient Energy Market, 20 December 2002, pg. 37.

[169] MCE, Statement on Upstream Gas Issues, December 2004, Attachment A.

[170] MCE, Statement on Upstream Gas Issues, December 2004.

[171] MCE and MCMPR, Joint Working Group on Natural Gas Supply – Terms of Reference, January 2007.

future development of the Australian gas market. The principles specified by the MCE included the following:[172]

- Information on market and system operations and capabilities at all stages of the gas supply chain (subject to recognition of existing contractual confidentialities) should be publicly available and frequently updated;
- The gas market structure should facilitate a competitive market in all sectors;
- Gas market participants should be able to freely trade between pipelines, regions and basins;
- There should be regulatory certainty and consistency across all jurisdictions; and
- Market design and institutional requirements should be responsive to and reflective of the needs of the market and market participants.

To facilitate debate on the development options, the Allen Consulting Group was engaged by the MCE to identify alternative options and to assess the compliance of these options with the overarching gas market development principles.

The Allen Consulting Group's final report was published in June 2005 and identified four options including: [173]

1. retain the current market and enable organic development;
2. retain the current market and introduce bulletin board (BB) facilities (see Box 8.1 for a description of the proposed BB);
3. adopt a city gate scheme or a short-term trading market (STTM) (see Box 8.2 for a description of the proposed city gate model); and
4. extend the Victorian model to other jurisdictions.

Box 8.1: Bulletin board proposal – Option 2

The Allen Consulting Group's proposed BB had the following features and attributes:

- The BB would facilitate trade between market participants (including shippers, pipeline operators, producers and retailers) who could post bids and offers for bilateral trades of surplus or deficit levels of gas and transmission capacity. The bids and offers could be voluntary and would not necessarily be standardised.
- The BB would not set spot prices nor would it impose mandatory mechanisms for the trading of imbalances.
- Short term trades would be recorded including the price and terms of each trade.
- In addition to bids and offers, the BB would publish information to assist participants identify any existing or impending shortfalls in production or pipeline capacity that may impede their ability to meet their supply commitments.

Sources: ACG, Options for the Development of the Australian Wholesale Gas Market, June 2005

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172 MCE, Statement on Principles for Gas Market Development, December 2004.

173 ACG, Options for the development of the Australian wholesale gas market, June 2005, pg. viii.

Box 8.2: City gate proposal – Option 3

The city gate proposal entailed the development of a spot market at the Sydney, Adelaide and Wallumbilla city gates which would be overseen by an independent operator. It was envisaged that this model would set a clearing price and compulsorily clear all imbalances the next day at the spot price.

Sources: ACG, Options for the Development of the Australian Wholesale Gas Market, June 2005

These four options were evaluated by the Allen Consulting Group on the basis of transparency and efficiency, practicality and simplicity, and implementation cost it was concluded that there was no single optimal option. Rather, the Allen Consulting Group concluded that the choice of any single option would involve a trade off between:[174]

- achieving efficiency and satisfying the gas market principles; and
- achieving practicability and low cost.

The Allen Consulting Group went on to observe that options 2 and 3 could be implemented on a relatively low cost basis and with minimal disruption to industry and noted that a model including both aspects could be developed.[175]

The MCE Standing Committee of Officials endorsed the Allen Consulting Group's conclusion that further reform of the wholesale gas market was required to improve transparency, enhance competition and reduce potential barriers to entry and in 2005 established an industry based working group, the Gas Market Leaders Group (GMLG), to further consider the options for development. [176]

The GMLG is comprised of twelve industry leaders representing gas producers, distribution and transmission owners and operators, retailers, wholesale market operators and users. This group was charged with the task of preparing a Gas Market Development Plan which would further develop both options 2 and 3 as identified in the Allen Consulting Group report or provide an alternative development plan that would provide equivalent benefits in terms of transparency and reducing barriers to market entry.[177]

The Gas Market Development Plan was submitted to the MCE in June 2006 and contained a number of recommendations including:[178]

- proceeding with the establishment of a BB which would cover all major gas production fields, major demand centres and transmission pipeline systems;
- developing a detailed design for a STTM to operate in all states except Victoria; and
- establishing a national Gas Market Operator.

In recommending the implementation of the BB, the GMLG noted that:

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174 ACG, Options for the development of the Australian wholesale gas market, June 2005, pg. ix.

175 ACG, Options for the development of the Australian wholesale gas market, June 2005, pg. ix.

176 MCE, Gas Market Leaders Group Gas Industry and Users Working Group to Develop a Gas Market Development Plan.

177 MCE, Gas Market Leaders Group Gas Industry and Users Working Group to Develop a Gas Market Development Plan.

178 Gas Market Leaders Group, National Gas Market Development Plan, June 2006, pp. 3-8.

> A BB may only be of limited value to existing major players in the national gas market who, through their existing contractual arrangements and industry networks, already have access to much of the information it would provide. However, there are potential benefits to end-users, smaller participants, new entrants and other market observers (including governments) through the ready availability of information provided by the BB enabling more efficient pricing decisions by market participants, resulting in net economic benefits, and facilitating better network management during a gas supply constraint.[179]

The specific recommendations made by the GMLG in relation to the BB are set out in Box 8.3.

In relation to the further development of the STTM, the GMLG made the following observations:[180]

§ The STTM will not replace bilaterally negotiated long-term contracts between shippers and producers, storage providers and pipeline operators as the primary mechanism for the wholesale sale and purchase of gas and gas transportation, or for underpinning investment. It will, however, allow retailers and direct, self-contracting users to purchase gas on a short-term basis without contracting for delivery. It will also allow those parties who have long-term supply and transportation agreements to manage short-term variations to their contracted quantities as their usage of gas changes from day to day;

§ The clearing prices determined at the hubs, together with published system supply/demand information, will provide pricing signals and facilitate secondary trading between transporters and users, for gas-fired power generators, for trading over interconnecting pipelines between hubs, and would facilitate greater demand side response by users, particularly at times of supply constraints;

§ The STTM will be of particular importance when a user's gas supplies are insufficient to meet demand, particularly during system constraints and emergencies. In those situations STTM participants will be able to trade and be financially compensated through the STTM for reducing demand; and

§ The BB would be an essential component of the STTM, but would be augmented to accommodate STTM bidding and pricing information.

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179 Gas Market Leaders Group, National Gas Market Development Plan, June 2006, pg. 4.

180 Gas Market Leaders Group, National Gas Market Development Plan, June 2006, pp. 5-7.

Box 8.3: Bulletin Board recommendations

The objective of a BB is to facilitate improved decision making and trade in gas through the provision of readily accessible and up-to-date system and market information.

The BB would be a single electronic communications system (website) covering all major production and pipeline systems, including the interconnected systems of South Australia, Victoria, Tasmania, New South Wales and the Australian Capital Territory, and including a linked but separate page for non-interconnected pipelines systems operating in Queensland, Western Australia and if practicable the Northern Territory.

The BB would not cover pipelines serving single users or small demand centres.

Published data would include a baseline set of information such as physical supply capacity, any temporary changes to the baseline information, available firm and non-firm pipeline capacity, pipeline tariffs, forecast daily demand (three days ahead) and key personnel contact details. The BB would not provide a mechanism for setting spot gas prices or trading imbalances.

Information published on the BB would be in aggregated form so as not to reveal commercially confidential details.

To achieve the intended transparency and availability of information, there should be public access to most, if not all, of the information provided on the BB. However, for reasons of commercial confidentiality and security, it may be necessary to develop "public" and "restricted" areas, with only registered parties having access to the restricted areas.

To operate effectively, provision of the physical system information for posting on the BB would need to be standardised and mandatory. This would require legal obligations on pipeline owners/operators, storage operators, producers and/or shippers to provide timely information in a specified, standard format.

Source: Gas Market Leaders Group, National Gas Market Development Plan, June 2006, pg. 3-4.

In relation to the development of a gas market operator, the GMLG noted that such an operator would be accorded the role of managing both the wholesale and retail gas markets and would therefore assume the retail market functions of GMC, REMCo and VENCorp. It was also envisaged that the gas market operator would administer the BB and, if progressed, the STTM. In addition it would publish an annual national gas supply and demand statement which would be of a similar nature to the Statement of Opportunities published by NEMMCO.[181]

In October 2006 the MCE instructed the GMLG:[182]

§ to establish a BB that facilitated transparent, real time and independent information to gas market participants and governments on the status of natural gas supplies across Australia;

§ to develop a design for the STTM, which included a mandatory price-based balancing mechanism for wholesale gas trading and make a recommendation on whether the STTM should be implemented; and

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181 Gas Market Leaders Group, National Gas Market Development Plan, June 2006, pp. 7-8.

182 Gas Market Leaders Group, Synopsis of 5th Meeting, 27 November 2006.

- provide further advice on the roles and responsibilities that should be accorded to the gas market operator.

Following a GMLG meeting in March 2007 it was noted that the BB would be operational by end March 2008 and that a decision on whether the STTM would go forward would be expected after the July 2007 meeting. If the STTM is to go ahead the GMLG expects the design to be completed by March 2008.[183]

The GMLG's recommendations in relation to the development of a Gas Market Operator were endorsed by the Energy Reform Implementation Group (ERIG) in its review of future energy reform which was released in January 2007.[184] In addition to endorsing the development of a single gas market operator, ERIG also referred to a number of factors that may impede access and efficiency in the gas market. The impediments referred to in this context included: joint marketing of gas by producers, inconsistencies in rule making and open access regimes to gas pipelines, and the lack of standardised and fungible gas contracts.[185] ERIG concluded that addressing these impediments would improve efficiency within the gas market.[186]

At its April 2007 meeting the Council of Australian Governments endorsed the development of a single energy market operator which would be responsible for both gas and electricity market operations.[187]

8.3. Regulation of transmission and distribution pipelines

On 30 June 2004 the Council of Australian Governments signed an inter-governmental agreement (the Australian Energy Market Agreement) which set out the timetable for the progressive introduction of governance arrangements and the establishment of the AEMC and the AER.

In addition to the change in governance arrangements it was agreed that a new national legal framework should be developed for the economic regulation of transmission and distribution pipeline assets consisting of:

- the National Gas Law which would be modified by Parliaments;
- the National Gas Rules which would be overseen by the AEMC; and
- statements of policy principle from the MCE to the AEMC.

To assist in the development of the national framework, the MCE engaged an independent expert panel to advise it of any issues that would need to be addressed to implement a national approach to energy access. The Expert Panel released its final recommendations in April 2006.[188] Drawing on the recommendations contained in the Expert Panel's report and

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[183] Gas Market Leaders Group, Synopsis of 7th Meeting, 29 March 2007.

[184] Energy Reform Implementation Group, Energy Reform – The Way Forward for Australia, January 2007, pg. 263.

[185] Energy Reform Implementation Group, Energy Reform – The Way Forward for Australia, January 2007, pg. 263.

[186] Energy Reform Implementation Group, Energy Reform – The Way Forward for Australia, January 2007, pg. 264.

[187] CoAG, Competition Reform April 2007, pg. 2.

[188] Expert Panel on Energy Access Pricing, Report to the Ministerial Council on Energy, April 2006.

the conclusions reached in relation to the Productivity Commission's review of the Gas Code, the MCE has developed exposure drafts of both the National Gas Law and the National Gas Rules. These exposure drafts have been subject to public consultation and are expected to be enacted at the end of 2007.[189]

[189] http://www.industry.gov.au/content/itrinternet/cmscontent.cfm?objectid=9055D6BE-BFEC-DB93-99380BEA3EFCFF18&indexPages=/content/sitemap.cfm?objectid=6439762A-B0D0-D18A-17289F60775A05B0

9. Issues for retail competition

Drawing on the material and observations presented in the preceding sections it is apparent that retailers operating in alternative jurisdictions in eastern Australia face distinct localised demand and supply conditions that vary in relation to:

- the size of the residential market (both in terms of the number of residential customers and the quantities of gas consumed) and the susceptibility of residential consumption to seasonal conditions;
- the type of gas available to be supplied to the retail market (ie, conventional natural gas versus coal seam methane) and the proximity of those reserves;
- the number of producers (or aggregators) willing to supply gas to a particular retail market;
- the commercial viability of transporting gas to the end location from alternative locations (where commercial viability refers to both the cost of transporting gas and the availability of capacity on the pipeline); and
- the accessibility to storage facilities and other risk management tools which enable the retailer to manage both gas supply and transportation arrangements so as to meet daily fluctuations in demand.

Table 9.1 sets out the principal differences that currently exist across the jurisdictions.

Table 9.1: Differences across the jurisdictions

	SA	Vic	NSW	ACT	Qld	Tas
Size of residential market						
No. of residential customers 2006	354,000	1,590,000	940,000	110,000	170,000	-
Quantities consumed 2004-05 (PJ)	10.23	92.12	21.49		2.45	-
Type of gas	CNG	CNG	CSM and CNG	CNG	CSM and CNG	CNG
Closest sources of supply	Cooper /Eromanga and Otway	Otway, Longford and Bass	Cooper/ Eromanga, Longford and Sydney Gas	Cooper/ Eromanga and Longford	Cooper/ Eromanga and Bowen/Surat	Longford
Pipelines and capacity constraints	MAP and SEA Gas SEA Gas almost fully contracted on a firm basis	PTS and Interconnect n.a.	MSP, EGP and Interconnect EGP potential firm capacity constraints from 2008. Interconnect northbound capacity constraints	MSP, EGP and Interconnect EGP potential firm capacity constraints from 2008. Interconnect northbound capacity constraints	SWQ and RBP RBP firm capacity constraints	TGP n.a.
Additional risk management tools	n.a.	WUGS, LNG Storage Facility, Spot Market	n.a.	n.a.	n.a.	n.a.

Given the jurisdiction-specific nature of many arrangements, any consideration of the influence of the upstream production and transmission segments on competition in the retail market should be undertaken separately for each jurisdiction.

To assist the AEMC with its consideration of this issue we have developed a list of factors that could be examined in each jurisdiction with a view to ascertaining the influence of the upstream and transmission segments of the gas supply chain on competition within a particular retail market.

In this context it is worth recognising that effective retail competition for the residential customer segment requires retailers, and particularly new entrant retailers, to be able to access competitively priced gas delivered at the city gate on a firm basis with a load profile that allows them to manage the consumption patterns of residential customers. The list of factors that has been developed therefore focuses on:

- the sources of supply to which a retailer has access;
- the commercial viability of alternative sources of supply on a delivered basis; and
- the availability of volume-based risk management tools, which enable a retailer to manage variations in residential demand.

There are also some specific issues that should be considered when examining the ability a new entrant gas retailer has to compete in a particular location. The factors that would inform this consideration are set out in the remainder of this section.

9.1. Sources of supply

Obtaining access to competitively priced gas will, in the first instance, depend on the sources of supply available at a particular location. A consideration of this issue will therefore take into account the following factors:

- the number of alternative sources of supply that can be delivered to the retailer’s end market;
- the ownership interests of these alternative sources with particular regard given to:
  - differences between the ownership structures of competing sources of supply; and
  - any interests retailers may have in these alternative sources;
- whether gas from alternative sources of supply are jointly marketed or sold independently by each of the joint venture parties;
- the production capacity and reserve levels of these alternative sources;
- the proportion of production capacity and reserves in each of these alternative sources that is uncontracted and therefore can be supplied to new entrants; and
- any gas supply developments that may become operational within the short to medium term and the extent that the production from these developments has already been committed under long term foundation contracts.

Given the declining reserve levels in some jurisdictions, consideration should also be given to the ability of alternative producers to meet a retailer's demand requirements over the medium term.

While there may be a number of alternative producers supplying a market, they may not all be able to supply gas on a firm basis and on the terms and conditions required by the buyer. In section 3.2.2 it was noted that coal seam methane has very different extraction characteristics to conventional natural gas and this can limit the ability of coal seam methane producers to supply gas with the volume flexibility required by retailers. Any assessment of the range of alternative sources of supply therefore needs to take this factor into account.

9.2. Commercial viability of alternative sources of supply

Where retailers in a particular location have access to more than one source of supply, consideration must also be given to the commercial viability of the alternative sources as this will directly influence the competitiveness of the delivered price. An assessment of the commercial viability will take into account:

§ the relative transportation costs from each of the alternative sources to the city gate; and

§ the extent to which the alternative pipelines have firm capacity constraints that may impede the ability of a retailer to obtain a firm supply of gas.

9.2.1. Relative transportation costs

The relative cost of transporting gas from the alternative sources of supply to the retailer's end market will depend on the proximity of these alternative sources of supply, and the tariffs and the tariff structures prevailing on the pipelines. Consideration of the commercial viability of alternative supply options should therefore take these factors into account.

A difference in transportation costs from alternative sources is not of itself *prima facie* evidence that a particular source of supply is not commercially viable. This is because differences in relative transportation costs may to some extent be shared between the producer and retailer (via a lower ex-plant price) in circumstances where a producer is seeking to compete on a delivered basis with gas supplied from alternative fields. The extent to which this sharing will occur will depend on the willingness of the producer to supply the particular location which will in turn depend on:

§ the extent of competition in the upstream market;

§ the extent to which the upstream interests differ across the alternative basins; and

§ the opportunity costs associated with supplying that location.

Finally, consideration should also be given to the type of transmission carriage model operating within the jurisdiction. In all jurisdictions excluding Victoria, bilateral contracts must be struck between the retailer and the pipeline owner which specify the capacity reservation required and have substantially capacity based charges. In contrast, the Victorian model allows a retailer to transport up to its AMDQ and to pay a throughput based charge. The distinction between these two models influences the accessibility a shipper has to firm transportation services and the overall structure of the delivered price.

9.2.2. Firm transportation capacity

Firm transportation capacity constraints may also influence the commercial viability of a supply option since retailers will require gas to be supplied on a firm basis. Where a transmission pipeline does have firm transportation capacity constraints it may still be possible for a retailer to obtain access to the pipeline if there are other users willing to trade capacity. The pipeline owner may also have plans to expand the pipeline and thus consideration should be given to the likely timing of this expansion and whether new users will be expected to contribute to the expansion.

9.3. Access to risk management tools

Where a retailer's residential customer base is particularly susceptible to seasonal influences then a retailer will also need to be able to have arrangements in place to ensure that it can meet peaks in consumption. Managing these seasonal variations in demand is costly and thus retailers operating in colder climates rely to a greater extent on access to competitively priced gas supply and transportation risk management tools. A consideration of this issue should therefore take into account:

- the manner by which these risks can be managed in a particular jurisdiction (ie, higher swing factor in the gas supply contract, storage facilities, spot market or bulletin board/short term trading market facilities); and
- the cost and availability of these risk management tools.

9.4. New entrants' ability to enter the market

From a new entrant's perspective the requirement that it commit to a long term gas supply contract specifying contracted quantities in the absence of an established customer base may be viewed as a barrier to entry. This barrier may be overcome if the new entrant can contract with an intermediary rather than contracting directly with a producer. Although the cost of purchasing gas from an intermediary would be expected to be higher than purchasing gas directly from producers (ie, once the intermediary's margin is included) this type of arrangement allows the retailer to minimise its commitment period and to establish a customer base in the short term before committing to a long term contract. The number of intermediaries offering to sell gas will therefore have an influence on competition in a retail market.

It is important to recognise in this context that the list of factors to consider may change if a decision is made to proceed with the implementation of short term trading markets at the city gates of Sydney, Adelaide and Wallumbilla. The establishment of such markets may alleviate some of the contracting issues faced by new entrant retailers while they are establishing a customer base.

The ability of a new entrant to compete effectively in the retail market will also depend on the extent to which the incumbent retailers in that jurisdiction have:

- upstream interests in production that can be used to supply the market on a more competitive basis to that available to the new entrant;

- operational control or an equity interest in transportation assets, which may influence the net price of transportation paid by the incumbent retailers relative to that paid by a new entrant;
- substantial capacity reservations on the transportation assets, which may affect the ability of the new entrant to obtain access to the services offered by those pipelines; and
- a portfolio of gas supply, storage and transportation contracts over which they can manage their volume and price risk relative to the new entrant.

The countervailing power held by incumbent retailers will also be an important factor to consider in this context.

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