PART ONE
ESSAY

AUSTRALIA'S NATURAL GAS MARKETS: THE EMERGENCE OF COMPETITION?

A Report by ACIL Tasman Pty Ltd

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E.1 Background

The period following the first discovery of natural gas in Australia at Roma, southern Queensland, in 1900 saw decades of sporadic development activity but little real progress toward establishment of a viable natural gas industry. The inability to access mass markets meant that production was limited to small quantities for use in the local area. It was not until the 1960s and early 1970s that the foundations of the Australian natural gas industry as we now know it were laid, with the discoveries of the Cooper Basin (1963), Gippsland Basin (1967) and North West Shelf gas fields (1971).

The key to making natural gas a mainstream fuel accessible to consumers in the major population centres was the establishment of gas transmission and distribution systems. The first of these, servicing Brisbane, was commissioned in 1967, followed by those servicing Melbourne (1968), Adelaide (1969), Perth (1972) and Sydney (1976).

The early phases of the development of the Australian natural gas industry were characterised by:

- limited competitive choice for customers: population centres and industrial sites with access to natural gas generally relied on a single source of supply delivered via a single transmission pipeline

- significant government ownership of assets and businesses, particularly in gas transmission and distribution infrastructure and retailing
- underwriting of infrastructure development by state governments, notably in Western Australia, South Australia and Victoria, where the states signed long-term foundation contracts that supported private investment in upstream and midstream developments.

The Australian natural gas industry has grown considerably over the past decade, and the structure and operation of the industry has changed as a result of privatisation, corporate activity and regulatory reform. The purpose of this essay is to provide an overview of the current gas market; to document the important policy reforms, structural changes and commercial developments that have reshaped the industry; and to look at the key drivers that will determine the direction of future developments.

Structure of the gas industry in Australia

The structure of the industry can usefully be considered from three perspectives: geographic, functional and commercial. These are discussed in the following sections.

Geographic structure of the industry

Geographically, the Australian natural gas industry can be separated into three regional markets, defined by the interconnected transmission pipeline systems that link upstream producers and downstream consumers:

- eastern Australia, including Queensland, New South Wales, the Australian Capital Territory (ACT), Victoria, Tasmania and South Australia
- the Northern Territory
- Western Australia.

Each of the regional markets can be subdivided into sub-regional market areas that represent clusters of supply and demand locations linked by transmission pipelines. These regional and sub-regional market areas are illustrated in figure E.1, which also indicates the size of the markets in terms of current levels of annual gas production and consumption.

In eastern Australia, Victoria has the strongest level of gas demand, currently estimated at around 244 petajoules per year (PJ/a). Queensland is now the second largest regional market, with demand expected to reach 190 PJ/a during 2008. Unlike Victoria, where demand is dominated by small customers with low individual consumption (residential, commercial and small industrial), the Queensland market is dominated by large industrial and power generation customers—both sectors that have grown rapidly in recent years.

Total gas demand in New South Wales (including the ACT) currently stands at around 150 PJ/a, and the state's customer profile is more like Victoria than Queensland. In South Australia, gas demand currently stands at around 107 PJ/a, having declined in recent years as a result of industrial plant closures and increased electricity imports. The Tasmanian market is in its formative stages—natural gas only became available following the commissioning of the Tasmania Gas Pipeline (Longford to Bell Bay, Hobart and Port Latta) in 2002. Demand is currently estimated at 12 PJ/a, principally for electricity generation, and will grow further with additional gas-fired power plant under construction.

For many years, the most important source of gas production in eastern Australia has been the Gippsland Basin, and it continues to be the largest producer in the region, at around 250 PJ/a. Over the past five years, new gas developments in the Bass Strait region (Otway and Bass basins) have seen the productive capacity of the region rise by more than 130 PJ/a, with further growth anticipated.

The other sources of conventional gas in eastern Australia are the Cooper Basin of South Australia and southwest Queensland—now in decline, with annual production currently between 140 and 150 PJ/a—and the Surat Basin and Denison Trough regions of southern Queensland, which produce around 26 PJ/a.

Figure E.1
Geographic distribution and size of gas markets in Australia

Source: ACIL Tasman compilation of various public sources.

In recent years, a major new source of gas supply for eastern Australia has emerged in the form of coal seam gas (CSG).[1] From a virtually zero base a decade ago, CSG production has risen to over 100 PJ/a in 2007, and is expected to reach as much as 160 PJ/a in 2008, with further strong growth anticipated.

The Northern Territory market is self-contained, with the current demand of around 21 PJ/a met from fields in the Amadeus Basin in Central Australia. As these fields deplete over the next few years, domestic supply will be drawn from the offshore Bonaparte Basin: the Blacktip field and associated infrastructure are currently under development to service the domestic market. The

1 Coal seam gas, also known as coal seam methane and (particularly in the USA) as coal bed methane, is natural gas (principally methane) that occurs naturally in coal seams. Although its production characteristics differ from conventional natural gas, processed coal seam gas is effectively indistinguishable from conventional gas. Coal seam gas typically meets standard pipeline gas specifications and can be routinely co-mingled with conventional gas.

alumina refinery at Gove, on the east Arnhem Land coast of the Gulf of Carpentaria, represents an additional potential gas load of around 45 PJ/a. However, despite previous plans for gas supply from Blacktip, and subsequently from Papua New Guinea, Gove remains isolated from gas supply and continues to operate using fuel oil. In 2006, Darwin became Australia's second liquefied natural gas (LNG) production centre, with the Darwin LNG plant now producing some 3 million tonnes of LNG per year (about 165 PJ/a) from the Bayu-Undan field in the Bonaparte Basin.

The Western Australian gas market remains isolated from the rest of the country. Over the past 40 years, there has been periodic enthusiasm for the concept of a transcontinental pipeline link, tying abundant and cheap gas production in the west with large domestic markets in the east. However, in recent times it has become clear that, while Western Australia's undeveloped offshore gas resources are undoubtedly abundant, they will not be cheap to develop and there is no commercial basis for integration of the Western Australian and east coast gas markets.

Domestic gas demand in Western Australia, at around 330 PJ/a, is currently higher than in any of the eastern states. Two-thirds of this demand is located in the southwest of the state (Perth–Kwinana–Bunbury), with the balance in the northwest (Burrup Peninsula and Pilbara region) and in the central Goldfields region. With the exception of a small contribution from the Perth Basin, all gas produced in Western Australia currently comes from the offshore Carnarvon Basin. Around two-thirds of this supply comes from the domestic gas production facilities associated with the North West Shelf gas project, which also supplies gas to Australia's first and largest LNG facility. With the commissioning of a fifth LNG train during 2008, the North West Shelf LNG project will have a production capacity of 16.3 million tonnes per year—equivalent to 900 PJ/a.

Australia's total production of LNG for export now stands at 1065 PJ/a—very close to the country's total domestic gas demand.

Functional structure of the industry: the natural gas supply chain

The natural gas industry involves a supply chain that includes the following functions:

- Upstream—exploration, development, production and processing of raw gas to produce sales gas that meets established quality specifications.
- Midstream—transportation of sales gas from upstream producers to downstream customers through high- and mid-pressure transmission pipeline systems.
- Downstream—wholesale supply of gas to major industrial and power generation facilities; low pressure pipeline distribution; and retail supply of gas to smaller industrial, commercial and household customers.

Upstream industry

The upstream gas industry covers the activities associated with exploration (seismic acquisition and exploration drilling), field development, gas gathering and processing. Typically, gas produced from a number of fields within a geological basin is transported to a central processing facility that effectively forms a hub around which subsequent exploration and development is focused. Examples of these processing hubs include the Moomba facility that services fields in the Cooper Basin in Central Australia, the Longford gas plant that processes gas from fields in the Gippsland Basin in Bass Strait, and the Wallumbilla hub that serves production facilities in the Surat Basin and Denison Trough areas of southern Queensland.

In order to spread risk, upstream activities are commonly carried out under joint venture arrangements in which several parties share the costs and risks of exploration as well as production entitlements. Commercial agreements between the joint venture parties set out the rights and obligations of the parties, as well as decision-making processes.

In the past, joint venturers typically chose to market their gas on common terms and conditions, including price, and to guarantee their income streams through long-term sales contracts with gas utilities and other large customers. Nowadays, it is more common for joint venture parties to engage in separate marketing, although there may be circumstances where joint marketing is seen to be commercially desirable.[2] To ensure that such activities are not in breach of the anti-competitive conduct provisions of the *Trade Practices Act 1974*, the parties may seek authorisation from the Australian Competition and Consumer Commission (ACCC) by demonstrating that, in the circumstances applying, the public benefits of joint marketing exceed any anti-competitive costs.

In terms of regulation, the view has generally been taken that the upstream gas industry does not have high enough barriers to entry, or great enough economies of scale, to warrant regulation of third party access (or the pricing of access) to facilities. This is largely non-contentious in relation to exploration activities but less clear cut in relation to processing facilities, where there may well be benefits to be gained from at least some degree of consolidation and centralisation of activities. In the absence of regulated access, the upstream industry has established a code of practice for third party access to processing facilities. This is further discussed in section E.2.

Midstream industry

The midstream industry functions relate to gas transmission—the transportation of gas, generally at high pressure and often over long distances, from the upstream sources of production to the downstream gas consumers.

Characteristically, gas transmission pipelines exhibit significant economies of scale. It is generally cheaper to expand an existing pipeline, either through installation of additional compression or through duplication of sections of the pipeline where capacity is constrained (a process known as looping), than it is to build a new pipeline. These characteristics mean that there is rarely any incentive for pipeline owners to invest in speculative spare capacity, since additional capacity can usually be added without incremental cost penalties as and when market demand arises. Because it is generally cheaper for an existing pipeline owner to expand capacity than for a new entrant to build a second pipeline between the same producer–customer pairing, transmission pipelines have natural monopoly characteristics. For this reason, the midstream industry is subject to access regulation.[3] Upstream competition may, however, emerge where there are multiple sources of supply that could service a particular market if transport pathways are available.

The objective of access regulation is to ensure that where the pipeline service provider is not subject to effective market competition, transportation services are nevertheless available to third party users on a non-discriminatory basis and at prices that reflect the efficient cost of providing the service. Regulation therefore seeks to achieve the outcomes that effective competition in the supply of transmission services, if it existed, would be expected to deliver. As discussed in section E.2, the number of transmission pipelines subject to third party access and tariff regulation is declining as new investment leads to an increasing number of gas wholesale and retail markets being serviced by multiple pipelines.

2 For example, the proponents of the PNG Gas Project, which was to deliver gas by pipeline from PNG to eastern Australia, successfully sought authorisation for joint marketing.

3 The regulatory instrument is the National Gas Rules, which took effect on 1 July 2008, replacing the National Third Party Access Code for Natural Gas Pipeline Systems (commonly referred to within the industry as the 'National Code').

Downstream industry

The downstream industry involves the wholesale supply of gas to large consumers, including major industrial and power generation sites, and the retail supply of gas primarily to small industrial, commercial and residential customers. It includes both transportation functions (distribution and reticulation) and sales functions (retail).

Transportation

The transportation of gas from the midstream high-pressure pipeline terminus (often referred to as the city gate) to small industrial, commercial and residential customers is a key function of the downstream gas industry. Gas distribution and reticulation is a regulated business function. Regulation under the National Third Party Access Code for Natural Gas Pipeline Systems (National Code) requires separation (ring-fencing) of gas distribution businesses from gas retail sales businesses and provides for non-discriminatory third party access under standardised terms, including reference tariffs.

Gas sales: wholesale and retail

The second area of downstream activity relates to the selling of gas and associated services. Sales activities are commonly separated into wholesale and retail, although the distinction is less clear cut than might be imagined: large-scale gas users—which might be thought of as 'wholesale customers'—have the choice of purchasing gas through a retailer or contracting directly with a gas producer. Some direct contracts are for supply on a *delivered basis* (in which case the gas producer arranges for transportation) or on an *ex-plant basis* (in which case the purchaser separately arranges with the relevant pipeline service provider for the gas to be delivered). Most very large users contract for supply directly, but this is not generally a practical approach for smaller users. Even some large gas consumers prefer to have a retailer deal with the upstream and midstream issues of gas procurement and transportation. Retailers may be able to use their purchasing power to secure gas supply and transportation on better terms than individual users. They may also be better able to manage supply risk by having access to a diverse portfolio of supply options that leaves the end-user less prone to interruption as a result of disruptions to any one source of supply.

The primary functions of gas retailers are:

- the sale and marketing of gas (both pipeline natural gas and liquefied petroleum gas) to customers
- the wholesale purchase of gas for retail on-sale to customers
- the provision of billing and other information to customers
- revenue collection and credit management
- customer service and contact (including the provision of telephone call centres for customer enquiries).

Natural gas retailing differs from electricity retailing due to the physical nature of the product. Gas retailers must ensure sufficient supply and transportation capability to maintain physical delivery to customers. As a result, retailers bundle together natural gas with transportation services when selling to customers.

Another key difference for retailers in the natural gas market is the lower degree of integration across the states. There is no single market operator providing standardised market clearing and other functions (as the National Electricity Market Management Company provides in electricity), with regulation and market management being the responsibility of the various state regulators.

Emergence of retail competition

Energy retailing in eastern Australia has undergone rapid development over the past decade:

- In most states monopoly (franchise) retailers have been replaced or augmented by private retailers as markets have been progressively opened to competition.
- Significant consolidation has occurred as competitors seek to gain economies of scale and pursue growth via merger and acquisition activity.
- Major private sector retailers have diversified geographically in order to grow their businesses and to diversify sources of risk and exposure to state wholesale markets.

- Retailers have sought to further increase customer numbers and reduce risks by diversifying into both gas and electricity where possible.
- Asset intensive, highly regulated network businesses have been split off from energy retailing businesses wherever privatisation has occurred.
- The largest private sector energy retailers have developed vertical integration strategies.

Typically, smaller customers and those in more remote locations (relative to the core of the distribution networks) face higher fixed costs of service. Prior to the era of deregulation, it was common for governments to regulate prices so that residential and rural regional customers paid prices below full cost recovery, while prices for larger users were often set above efficient levels. While many jurisdictions continue to regulate default retail gas prices, regulatory reform over the past decade has been directed toward removing cross-subsidies and achieving cost-reflective pricing across the full range of users.

Retail convergence and dual fuel services

Increasingly the Australian market has seen a convergence in the retail sector between electricity and gas, with most retailers now offering both gas and electricity as part of a comprehensive energy services offering. There have even been moves—in line with trends in some overseas countries—to incorporate data and telecommunication services, although the integrated utilities retailer model has yet to find much traction here.

The primary benefits of operating as a dual fuel retailer are:

- cost savings associated with retail costs by combining separate gas and electricity retail functions such as billing systems, call centres, marketing and administration
- offering bundled dual fuel products to customers, potentially providing discounts unable to be matched by single fuel retailers.

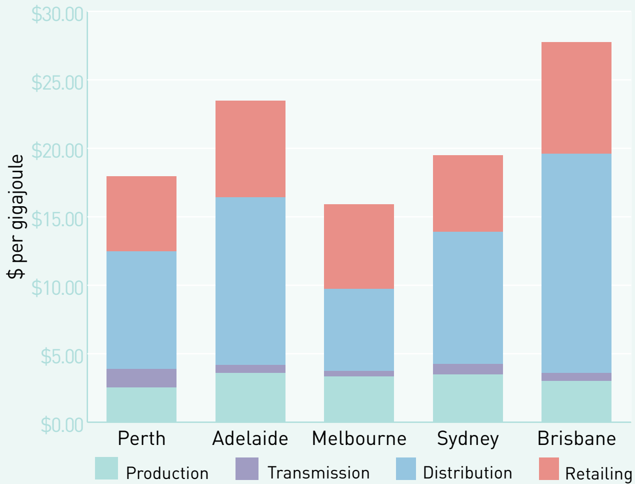
Retail gas pricing

The delivered price of gas to retail consumers includes charges for each element in the supply chain: payments to the upstream producers for the gas itself; to the transmission pipeline and distribution system operators for use of their transport systems; and to the retailer for provision of retail services including gas portfolio management, meter reading, and customer account maintenance and billing.

There are significant fixed cost components in the overall service package, and those costs vary considerably depending on the geographical location of the customer. As a result, prices vary significantly for customers with different volume requirements and at different locations. Because of the many differences in costs and circumstances across regional supply chains, comparing the retail price of gas at different locations needs to be approached cautiously: 'apples with apples' comparisons are difficult. Customers vary greatly both within and between regions, and the prices they face vary accordingly. So, for example, the average residential gas customer in Victoria consumes around 65 GJ/a—more than three times the annual consumption of the average Queensland residential customer. It is nevertheless revealing to examine how indicative gas prices vary by location, and what components make up those prices. Figure E.2 illustrates the components of retail residential gas prices in the mainland state capital cities for typical residential customers in those locations. Total prices range from around $15.50 per GJ in Melbourne to almost $28 per GJ in Brisbane

Upstream costs associated with the extraction and production of the gas itself account for a relatively small proportion of total cost—between 11 and 21 per cent. Transportation through the high pressure transmission system is the smallest contributor to delivered costs for residential consumers in the capital cities (2 to 7 per cent). The total upstream and midstream costs therefore account for only around 15 per cent of delivered cost to residential customers. For larger industrial users, this proportion rises steadily with scale as the fixed costs associated with downstream services are spread across much larger gas supply volumes.

Figure E.2
Components of retail residential gas price



Source: ACIL Tasman analysis based on wholesale gas price estimates, regulated and posted tariffs for transmission and distribution services, and published retail gas prices for residential customers.

By far the highest proportion of total cost is associated with the low pressure distribution system (38 to 58 per cent) reflecting the high capital cost to service each customer. The proportionate cost associated with distribution is greatest in Queensland, where average gas consumption per customer is lowest, and conversely, is lowest in Victoria, where average gas consumption per customer is highest. Retailing typically accounts for around 30 per cent of total costs and is relatively uniform across the regions, ranging from $5.50 to $8.00 per GJ.

Commercial structure of the industry

The final basis of characterisation of the Australian natural gas industry is in terms of the commercial relationships between the functional participants.

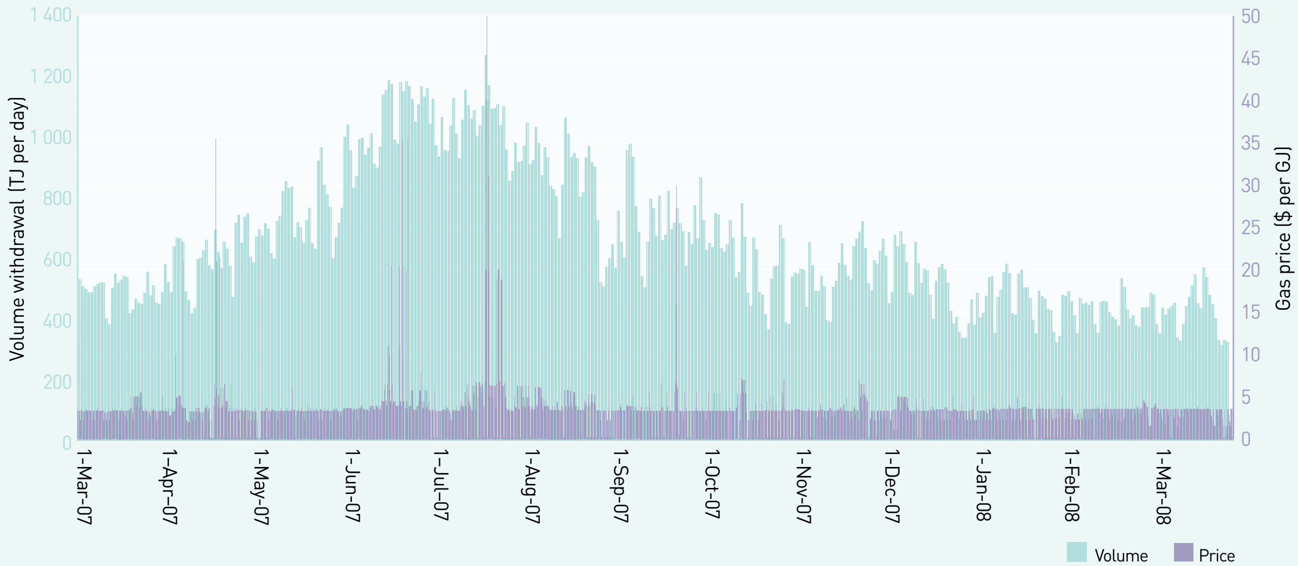
Historically most of the gas in Australia has been bought and sold on the basis of long-term bilateral contracts. These contracts between gas producers and wholesale gas buyers, between producers and transporters, and between transporters and wholesale consumers, have typically been for terms of 10 to 20 years. There has been a trend in recent years toward shorter term supply, but most gas supply and transportation contracts still run for at least five years. Foundation contracts underpinning new facilities development (production projects and major gas-consuming plants) are still often settled for terms of up to 20 years. Indeed, it is commonly argued that such long-term contracts are essential to the financing of new projects because they provide reasonable security of long-term gas supply as well as a degree of cost and revenue stability.

Periodic price review mechanisms, which provide some protection to both buyers and sellers against prices moving and remaining seriously 'out of market', are a feature of most long-term gas supply contracts. Between reviews, prices are typically defined according to a base price indexed regularly (most often to the consumer price index (CPI)). Contract prices therefore do not tend to fluctuate on a daily or seasonal basis. However, the many variations in detailed commercial provisions such as term, volume, volume flexibility (minimum bill or 'take-or-pay' levels; banking rights; relationships between annual contract quantities and maximum daily quantities), penalties associated with failure to supply, and so forth mean that there can be very significant price differences between contracts. Hence, the idea of a single market clearing price has little relevance in the current Australian market.

The only state where there is a formal short-term trading market is Victoria. In Victoria, a spot market has operated since privatisation of the state-owned transmission, distribution and retail gas businesses during the 1990s. As well as trading functions, the Victorian market operator (VENCorp) also provides market-based system balancing. In other jurisdictions, system balancing is physically managed by system operators (such as REMCo), but financial arrangements are otherwise undertaken by transmission and distribution system operators. The Victorian market is discussed in more detail below.

The predominance of long-term gas supply and transportation contracts, together with the lack of active spot markets (outside Victoria) has resulted in a lack of market transparency. The long-term contracts that define the market commercially are typically subject to strict confidentiality provisions. As a result, there is little public domain information regarding levels of uncontracted

Figure E.3
Victorian natural gas spot prices and volumes



Notes: Price display capped at $50 per GJ for readability; actual spot price in July 2007 reached maximum of $336 per GJ.
Source: VENCorp.

gas supply, demand, price and other commercial variables. Steps are being taken to address this lack of transparency through the Gas Market Reform initiatives currently being pursued by the Council of Australian Governments (COAG). These reforms are discussed in section E.2.

Victorian spot market

The Victorian spot market, operated by VENCorp, operates to balance daily requirements between retailers and suppliers. While the market is still underpinned by long-term bilateral contracts, the spot market provides both a balancing mechanism and a means by which sellers and buyers are able to trade contractual entitlements on a short-term basis.

Spot price volatility and volumes of natural gas sold in the Victorian pool from March 2007 to March 2008 are summarised in figure E.3.

The wide range in volume from less than 400 terajoules per day (TJ/d) to 1200 TJ/d reflects the large seasonal load swing in the Victorian market, with high demand during the cool winter months and much lower demand during summer. Significant volatility in spot prices occurred in mid-2007, partly due to water shortages curtailing electricity generation by hydro plants, which in turn drove up demand for gas for generation. While spot prices peaked at very high levels (up to $336 per GJ in July 2007), prices in the Victorian spot market mostly reflect underlying contract prices, currently ranging between $3.35 and $3.60 per GJ. The Victorian market therefore provides a clearing house in which gas can be bought and sold on an intra-daily basis, with prices reflecting the short-term supply–demand balance, while underlying long-term supply contracts insulate major buyers and sellers from price volatility in much the same way that hedge contracts operate to manage price risk for electricity generators and retailers in the National Electricity Market.

Market participants

Figure E.4 summarises the main participants in the upstream, midstream and downstream sectors of the east coast, Northern Territory and Western Australian gas markets.

Figure E.4
Gas market participants

UPSTREAM	MIDSTREAM	DOWNSTREAM
Gas exploration, production and processing	Gas transmission	Gas distribution and retail
EASTERN AUSTRALIA	EASTERN AUSTRALIA	EASTERN AUSTRALIA
PRODUCTION > Esso/BHP Billiton (46.2%) > Santos (24.7%) > Origin (10.8%) > Beach (5.0%) > AWE (2.6%) > Qld Gas (2.3%) > Arrow/AGL (1.8%) > Others (6.6%)	TRANSMISSION > **APA Group:** Roma–Brisbane, Carpentaria, Moomba–Sydney, Central West, Victoria PTS, SEA Gas [part] > **Epic Energy:** SWQP, MAPS > **SPI:** QGP, EGP/VicHub > **BBI:** Tasmania GP > **International Power:** SEA Gas [part] > **TRUenergy:** SEA Gas [part] > **AGL/Arrow:** NQGP	DISTRIBUTION > **APA Group:** Brisbane Sth/Southeast Qld, Vic United > **Envestra:** Adelaide/SA regional, Vic regional, Brisbane Nth, Central Qld (coastal) > **SPI:** NSW/ACT > **BBI:** Vic Multinet > **SP AusNet:** Vic regional RETAIL > **ActewAGL:** (NSW/ACT) > **AGL Energy:** (all except Tas) > **Aurora:** (Tas) > **Australian Power & Gas:** (Vic, NSW, Qld) > **Country Energy:** (NSW/ACT) > **EnergyAustralia:** (NSW/ACT/Vic/SA) > **Simply Energy:** (Vic/SA) > **Option One:** (Tas) > **Origin Energy:** (all except Tas, ACT) > **TRUenergy:** (Vic,NSW,SA)
NORTHERN TERRITORY	NORTHERN TERRITORY	NORTHERN TERRITORY
PRODUCTION > Santos (62%) > Magellan (38%)	TRANSMISSION > **APA Group:** Amadeus–Darwin > **Envestra:** Palm Valley–Alice Springs	RETAIL > NT Gas
WESTERN AUSTRALIA	WESTERN AUSTRALIA	WESTERN AUSTRALIA
PRODUCTION > North West Shelf JV (65.0%) > Apache (20.2%) > Santos (9.8%) > ARC Energy (1.8%) > Origin (1.5%) > Others (1.7%)	TRANSMISSION > **DUET:** Dampier Bunbury Pipeline > **APA Group:** Parmelia Pipeline Goldfields Gas Transmission, Telfer Pipeline, MidWest Pipeline > **Epic Energy:** Pilbara Energy Pipeline	DISTRIBUTION > **BBI:** Perth, SW, Geraldton, Kalgoorlie distribution RETAIL > Synergy > Perth Energy > Verve Energy

Note: Some corporate names have been abbreviated or shortened.

Source: ACIL Tasman, production data from EnergyQuest.

E.2 A decade of regulatory reform and policy development

Major regulatory reform of the Australian gas industry commenced in the mid-1990s driven by two separate but related developments:

- The Competition Policy Reform agenda of COAG following the release of the Hilmer Report on National Competition Policy. In particular, COAG drove the removal of barriers to interstate trade in gas. It oversaw the industry-led review of impediments to competition in upstream gas exploration and production, the establishment of the National Code regulating third party access to natural gas transmission and distribution systems, and the transition to full contestability in retail energy markets (gas and electricity).
- Privatisation of government-owned gas businesses (principally midstream and downstream).

As a result of these reforms, the gas industry in 2008 is vastly different from the industry a decade earlier. Ownership and operation of gas transmission pipelines is now entirely in private hands; new transmission pipelines have been built to service a greatly increased level of interstate trade in gas (Victoria to New South Wales, Victoria to South Australia, Victoria to Tasmania and, by early 2009, Queensland to New South Wales and South Australia). Government-owned gas distribution businesses have also been privatised in Western Australia, South Australia, Victoria and Queensland, as have gas retail businesses in the mainland eastern states.[4] This section discusses these reforms in more detail.

Upstream gas industry reform

A number of industry reviews have addressed potential impediments to competition in the upstream gas industry, starting with the Upstream Issues Working Group (UIWG) convened by COAG in 1998. The UIWG focused on three main issues:

- joint marketing
- third party access to production facilities
- management of exploration acreage and, in particular, administration of relinquishment requirements to ensure that prospective land is not locked up by titleholders that lack either the resources or the commercial incentives to explore for and to develop viable resources.

Subsequent consideration of upstream issues (the Parer Report, 2002;[5] the Ministerial Council on Minerals & Petroleum Resources (MCMPR) and the Ministerial Council on Energy (MCE)[6]) has focused primarily on these same issues. The current position is that the MCMPR has recommended, and the MCE has agreed, that:

- there is no case for prohibiting joint marketing of gas: applications for authorisation of joint marketing under the *Trade Practices Act 1974* should continue to be considered on a case by case basis
- there is 'no systematic problem concerning exploration effort in production licence areas' and hence no change to current administrative policy and practice for acreage management is required
- the industry code of practice governing third party access to upstream production facilities should be reviewed.

Midstream reform—the National Code

In November 1997, the Australian Government, states and territories agreed to enact legislation to apply a uniform national framework for third party access to all gas pipelines. This framework included the Gas Pipelines Access Law and the National Code. The National

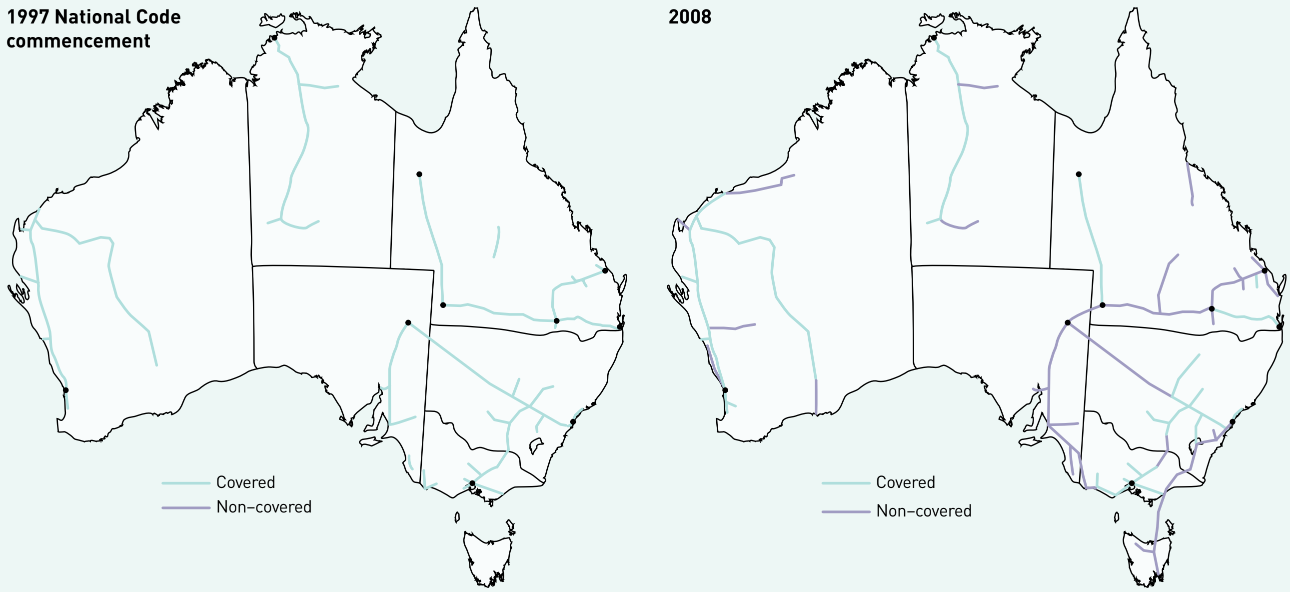
4 The New South Wales gas distribution and retail sectors have always been privately owned.

5 Parer, Warwick & others: *Towards a Truly National and Efficient Energy Market*, Commonwealth of Australia, 20 December 2002.

6 Ministerial Council on Energy (MCE) *Statement on upstream gas issues*, December 2004; Terms of Reference, MCE and MCMPR Joint Working Group on Natural Gas Supply, January 2007.

Figure E.5

Natural gas transmission pipeline developments since introduction of the National Code



Sources: ACIL Tasman; National Competition Council.

Code establishes the rights and obligations of pipeline operators and users in relation to third party access to natural gas transmission and distribution. It is designed to replicate competitive market outcomes where the monopoly characteristics of pipelines facilities might otherwise hinder third party access and the competitive supply of gas.

These regulatory arrangements recognised that transmission pipelines play a critical role in promoting effective competition in the Australian gas market. For new sources of production to enter the market, and to ensure that consumers are able to take advantage of competitive supply as those new sources emerge, access to transmission pipeline capacity on fair and reasonable terms is essential. Conversely, unregulated power to control access to transport services through transmission and distribution systems would have the potential to suppress competition by denying alternative producers a pathway to market.

Upon its introduction, the National Code applied to most of the major natural gas transmission and distribution pipeline systems. Subsequently, new pipelines meeting the coverage criteria of the National Code have also been covered. However, over the past 10 years, new pipeline interconnections and the expansion of existing pipeline systems have seen a significant increase in the level of supply-side competition in major gas markets, particularly in South Australia, New South Wales and Victoria. Major new transmission pipelines, including the Eastern Gas Pipeline (Longford–Sydney), the SEA Gas Pipeline (Western Victoria–Adelaide) and the Tasmania Gas Pipeline, are not covered under the National Code (though their operators typically offer access to uncontracted capacity under voluntarily offered standard terms and conditions). The trend to increased interconnection and reduced regulation is shown in figure E.5, which compares the extent of the transmission pipeline network and the incidence of regulatory coverage between commencement of the National Code in 1997 and the present. As shown, coverage on a number of pipelines pre-dating the National Code has been partly or fully revoked, reflecting in a number of instances the increased level of competition within the interconnected markets.

Downstream reform

In the downstream sector, the regulatory reform process can be divided into reforms to distribution and retail market reform. Distribution sector reform has largely followed the transmission sector, although given the nature of distribution there has been less activity in terms of entry of new competitors in particular distribution regions, with new investment mainly related to incremental expansion of service areas by the incumbent operators.

Within the retail sector, the key area of reform has been the move to full retail contestability (FRC), which has in effect removed the monopoly service rights and obligations under the former franchise arrangements, and replaced them with a competitive market environment in which any qualified service provider may compete for retail customers, subject to certain consumer protection arrangements. The introduction of FRC has occurred in a staged manner across each of the state jurisdictions, with larger industrial customers becoming contestable first and smaller customers later. For example, customers consuming more than 500 TJ/a became contestable in New South Wales from August 1996, whereas small residential and commercial customers (less than 1 TJ/a) did not become contestable until January 2002. The tranche definitions as well as the timing of contestability for individual tranches varied from state to state, with Queensland being the last of the eastern Australian mainland jurisdictions to move to FRC for all customer groups. Small customers (less than 1 TJ/a) became contestable in Queensland from July 2007.

Implementation of FRC in the small user segment has necessitated the introduction of retail market operators[7] to process customer transfers between retailers, to provide technical support and to administer market rules. The market operators are also responsible for daily gas usage allocation between retailers and gas balancing to maintain system security.

The retail market operators are funded by fees paid by distributors and retailers.

Regulation of transmission and distribution

The Gas Pipelines Access Law and the National Code provided, with limited amendment, the basis for regulation of gas transmission and distribution from 1997 until July 2008. Recognising the evolving requirements for regulation of the midstream gas industry, the Australian Energy Market Agreement signed by COAG in June 2004 included provisions for the development of a new national legal framework for the economic regulation of transmission and distribution pipeline assets. An independent expert panel was established to advise the MCE of issues to be addressed in implementing a national approach to energy access. The final recommendations of the expert panel were released in April 2006.[8] These recommendations, together with the conclusions reached in the Productivity Commission's earlier review of the National Code, have been incorporated into the new National Gas Law and the corresponding National Gas Rules, which effectively replaced the National Code on 1 July 2008.

The National Gas Law transfers the administration and enforcement of the existing gas access regimes from state-based regulators to the national bodies, the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). These changes are intended to provide a regulatory framework that supports efficient new pipeline investment while ensuring the interests of participants in both upstream and downstream markets, including users and customers, are appropriately considered.

7 Victoria has had a market operator (VENCorp) in place for both electricity and gas since market establishment in 1997. The retail market operator in New South Wales and the ACT is the Gas Market Company (GMC), while in South Australia this function is carried out by REMCo. Queensland has appointed VENCorp as its market operator.

8 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006.

Transfer of regulatory responsibilities

The National Gas Law sets out the basis for the AEMC as having responsibility for rule making and market development, and the AER as the national regulator. It provides for the AER to take on, amongst other responsibilities, the regulatory functions for gas transmission pipelines previously undertaken by the ACCC and the regulation of gas distribution, which is currently the responsibility of the various state jurisdictions. The role of gas transmission regulator transferred from the ACCC to the AER on 1 July 2008. The transfer of responsibility for regulation of gas distribution from jurisdictional regulators to the AER also occurred at that time. In Western Australia, the Economic Regulation Authority (ERA) will continue to regulate the gas pipeline sector.

Gas market reform looking forward

Despite the many changes that have occurred in the Australian gas market over the past decade, the reform agenda is by no means complete. Ongoing work is currently focused on the development of mechanisms to encourage greater transparency and efficiency in market operations; reform of transmission and distribution pipeline regulation; and long-term security of supply for domestic gas markets.

Gas market development

In December 2004, the MCE agreed to a set of principles designed to guide the future development of Australian gas markets:

- **Increased transparency:** up-to-date information on market and system operations and capabilities at all stages of the gas supply chain should be publicly available.
- **Competitive structure:** the gas market should be structured to facilitate a competitive market in all sectors and to promote further efficient investment in gas infrastructure.
- **Freedom of trade:** gas market participants should be able to freely trade between pipelines, regions and basins.
- **Clear rules:** there should be regulatory certainty and consistency across all jurisdictions, including arrangements for efficient management of supply and demand interruptions.
- **Fitness for purpose:** market design and institutional requirements should be responsive to and reflective of the needs of the market and market participants.

In November 2005, the MCE established an industry-led Gas Market Leaders Group (GMLG) to prepare a Gas Market Development Plan.

The GMLG provided its plan in June 2006 and has since been reconvened to progress two key recommendations:

- **Establishment of a bulletin board system:** the gas market bulletin board, launched on 1 July 2008, provides real time information to gas market participants and governments on the status of natural gas supplies around the country. It also supports the information requirements of the National Gas Emergency Response Protocol.
- **Design of a short term trading market:** the short-term trading market, scheduled to commence before winter 2010, will provide a mandatory price-based balancing mechanism for wholesale gas trading.

Australian Energy Market Operator

Concurrently, the MCE agreed to a detailed implementation plan for a single Australian Energy Market Operator (AEMO), responsible for the operation of both the electricity and gas industries. This AEMO would integrate the role of the National Electricity Market Management Company and existing state-based gas market operators. The timeline set by COAG for the establishment of the AEMO is June 2009.

Long-term domestic gas supply

A joint working group (JWG) established by the MCE[9] has considered how best to balance the dual objectives of building Australia's LNG export capabilities while at the same time ensuring the long-term supply of competitively priced gas for domestic users. The significance of this issue has been highlighted by recent circumstances in Western Australia, where tight supply conditions and steeply rising domestic gas prices have emerged. At the same time, record oil prices have driven international gas prices to an all-time high, and proposals for new large-scale LNG export facilities are being progressed. Rapidly growing international demand, driven by strong economic growth in China, India and elsewhere in eastern Asia, is opening unprecedented opportunities for Australian LNG exports. At the same time, Australian governments are pursuing policies to ameliorate the effects of carbon emissions on climate change. These policies will place increased demands on natural gas as a cleaner fuel alternative for power generation, providing a bridge between current coal-based technologies and low emission technologies that may provide long-term solutions, but that are unlikely to be available for large-scale commercial deployment for at least a decade.

In light of these developments, the JWG was asked to consider issues relating to the domestic gas supply and demand balance for gas; barriers to domestic supply; and strategies to ensure availability of competitively priced gas. The JWG also considered risks associated with major inter-regional projects, and policies to facilitate development of natural gas resources for both export and long-term domestic requirements.

The final report of the JWG, released in September 2007, recommended that attention be centred on the following key priorities:

- **Acreage management:** further investigation into improving current acreage management processes—in particular, the granting and renewal of retention leases to ensure that processes are transparent and that tests of commerciality are rigorously applied and enforced.
- **Improving the operation of existing market structures:** development and implementation of a short-term trading market for natural gas and a bulletin board covering all major gas production fields, major demand centres and transmission pipeline systems.
- **Developing an annual national gas statement of opportunities:** a national gas statement of opportunities (GSOO), similar to existing opportunity statements for the electricity sector, to be prepared by the AEMO with the objective of assisting existing participants and potential new entrants to identify investment opportunities and manage their positions in the market. The GSOO would also be available as an information tool for policy makers examining the projected short- and long-term reliability of the nation's gas supply.
- **Obtaining a better understanding of new market developments:** areas identified for further investigation include the likely impacts of a national emission trading scheme, east coast LNG developments, and increased use of gas in transport fuels.

E.3 Current status and future market directions

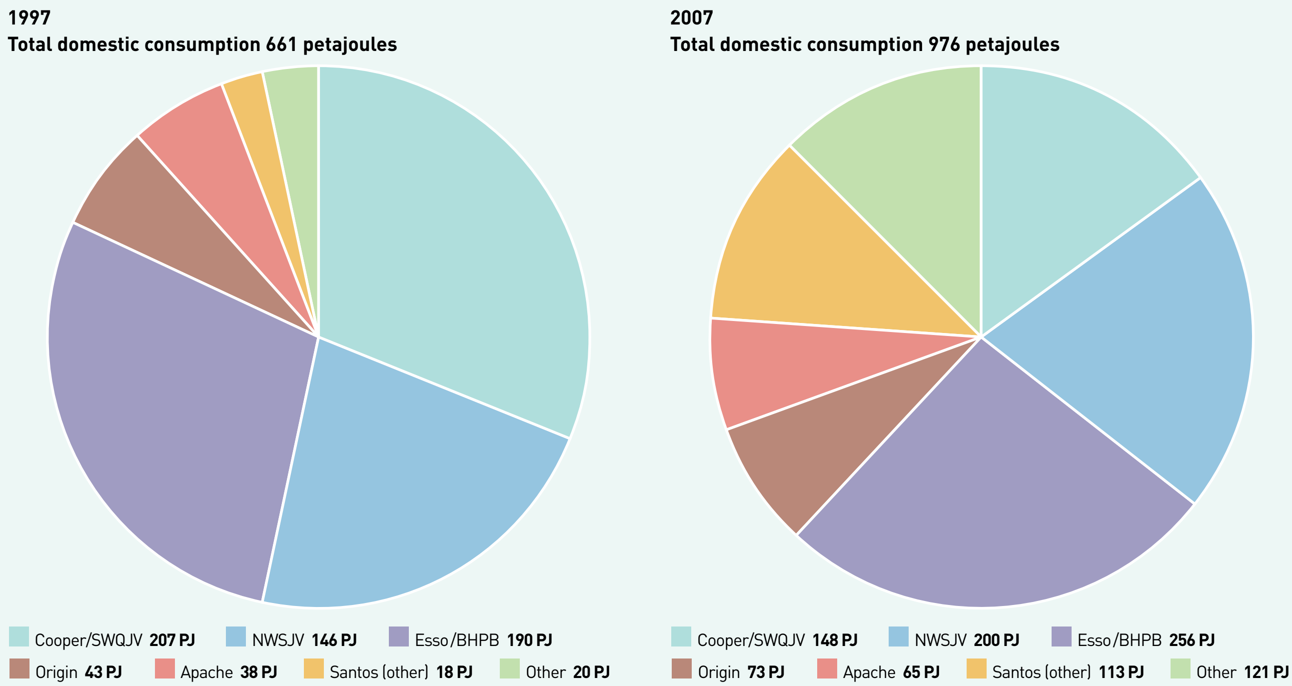
The success of competition reform in encouraging market growth and diversification in the gas industry can be gauged by comparing the patterns of production and investment prior to the commencement of the reform process with those currently prevailing.

Figure E.6 draws on statistics maintained by the Australian Petroleum Production and Exploration Association (APPEA) to compare the quantities of gas produced in Australia for domestic consumption in 1997 with 2007 data, as well as the distribution of production between different producer companies. It is evident that, across that period, there has been considerable expansion and diversification in the upstream industry as reflected in domestic gas supply. Total domestic gas consumption over that period rose from 661 petajoules to

9 MCE and MCMPR Joint Working Group on Natural Gas Supply—Terms of Reference, January 2007.

Figure E.6

Gas production for the domestic market—1997 and 2007 (petajoules)



Notes: Includes coal seam gas.
Source: ACIL Tasman analysis using APPEA data.

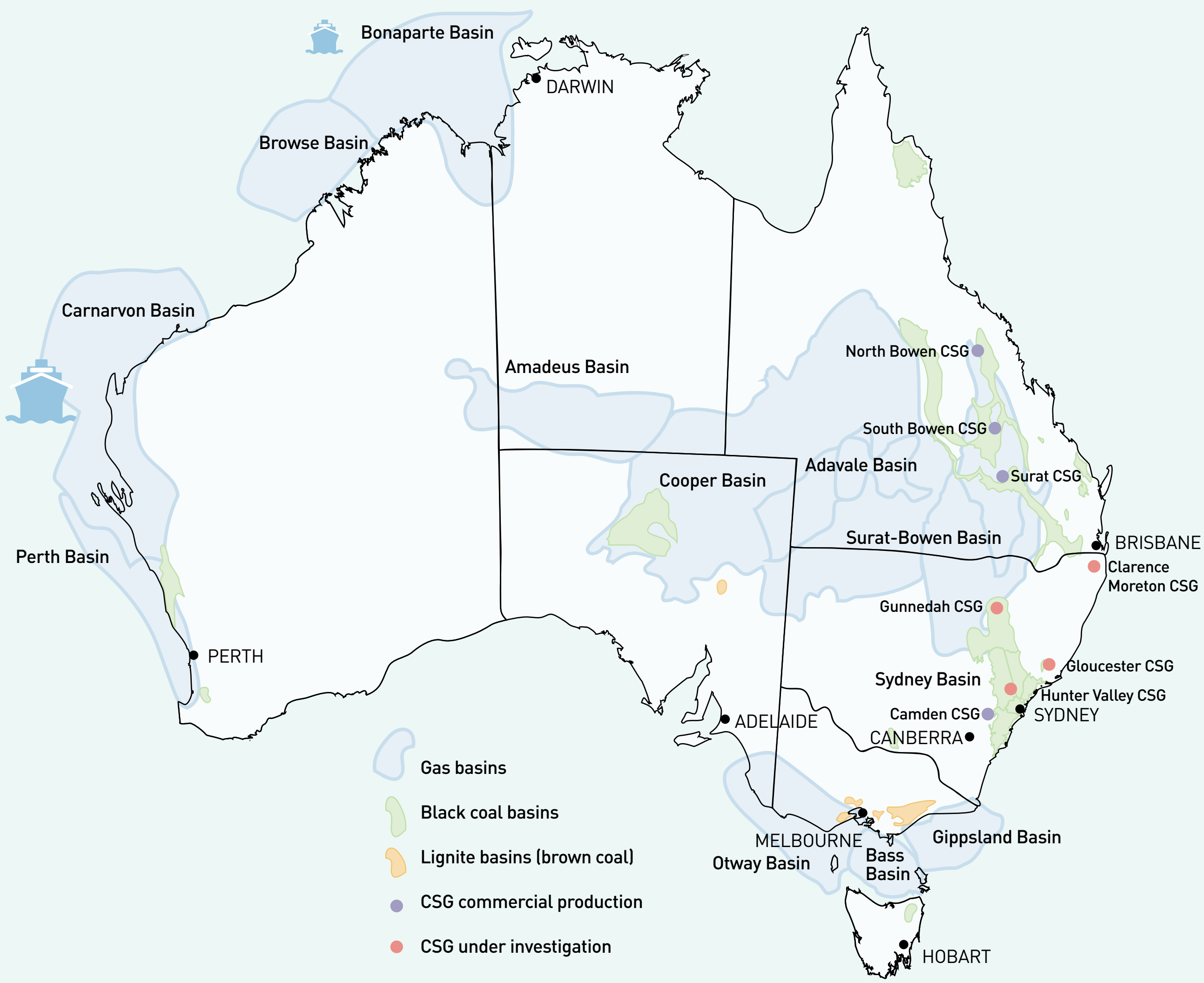
976 petajoules, reflecting an average compound annual growth rate of 4 per cent. In terms of diversification, the three major producers in 1997—Esso/BHP Billiton from the Gippsland Basin, the Cooper Basin and South West Queensland Joint Ventures (SWQJV) in Central Australia, and the North West Shelf Joint Domestic Gas JV (NWSJV) in Western Australia—represented more than 82 per cent of the total market. In 2007, the proportion of domestic supply from these sources had fallen to under 62 per cent.

Emerging supply sources

By the late 1990s, it had become clear that the established sources of gas supply in the Gippsland and Cooper Basins would not support longer-term market growth in eastern Australia, and that alternative sources of gas would be needed. With limited expectations of new conventional gas discoveries in eastern Australia, attention increasingly turned to the north—to Papua New Guinea (PNG), to the Timor Sea, and even to the Browse Basin off the northwest coast of Western Australia—for possible new sources of supply. For much of the past decade, the PNG Gas Project was seen by many as the most likely new, long-term source of competitive gas supply for markets in eastern Australia. However, what emerged was something quite different. The local market responded to the anticipated entry of PNG gas in various ways, and the emerging market reforms supported those responses. New sources of conventional gas were identified and developed in the Bass Strait region, both in the established Gippsland Basin province and further west in the Bass and Otway basins. New producers entered the market. Long-term contracts for interstate supply were settled, with transportation of gas via new cross-border transmission pipelines occurring. Perhaps most significantly, exploration for CSG—which had enjoyed limited success in Queensland through the previous decade —began to gain real traction in terms of production and resources, and to achieve commercial acceptance. CSG won several major supply contracts that might otherwise have provided the market underpinning for the PNG Gas Project.

Figure E.7

Coal seam gas prospects in eastern Australia



Source: Base map from AER, 2007.

In the meantime, developments in world energy markets saw steep increases in the price of gas internationally, while gas prices in Australia remained low by world standards, constrained by competition from low-cost coal and cheap coal-fired electricity. By early 2007, value relativities had shifted to the point where the PNG gas proponents saw greater value in developing their resources for sale on international markets as LNG and the proposed pipeline to eastern Australia was shelved.

The emergence of coal seam gas

The extensive resources of black coal that support a world-scale export coal industry in Queensland and New South Wales also host vast quantities of gas (mainly methane) that is a close substitute for conventional natural gas. In Australia, this gas is most often referred to as coal seam gas (CSG). The key to commercial extraction of CSG lies in finding ways to extract gas from coal seams, which typically have low permeability, at sustainable rates high enough to justify the costs of drilling and production. The most prospective sites for CSG exploration and production are the Bowen and

Surat Basins in Queensland and the Sydney, Gunnedah, Gloucester and Clarence-Moreton Basins in New South Wales. The southern and central Queensland locations are now the clear leaders in terms of both reserves and production, and it is from these areas that much of the short-term supply growth is expected. However, there are good prospects also in New South Wales where coal measure sequences geologically similar to those in Queensland are now being tested in a number of locations. These locations are shown in figure E.7.

Both reserves and production of CSG have increased over the past five years, as illustrated in figure E.8.

Levels of independently certified reserves continue to grow rapidly. By the end of 2007, levels had reached around 7200 PJ of proven and probable reserves.

Production of CSG exceeded 100 PJ for the first time in calendar 2007, contributing almost 15 per cent of the total gas supply in eastern Australia. Production continues to rise and, with a number of projects ramping up to meet contractual commitments, there is no sign of a slow-down in production growth from the CSG sector.

Figure E.8

Eastern Australia coal seam gas reserves and production growth

Note: reserves include proved, plus probable reserves.

Source: ACIL Tasman compilation of various company disclosures.

Liquefied natural gas exports from eastern Australia?

Until recently, eastern Australia had not been considered a prospective location for LNG manufacturing, principally because uncommitted conventional gas resources in the region were inadequate to support a world-scale LNG facility. However, the recent surge in international energy prices, together with the identification of large resources of CSG in southern and central Queensland, has changed the prospects for east coast LNG. Since early 2007, four LNG proposals based on CSG feed from the Bowen and Surat Basins have been announced. The projects range in size from 0.5 to 4 million tonnes per year, with potential in each case for increased production with the replication of the initial liquefaction plant.

While there are technical and commercial challenges, there is a compelling logic to the attempts of the proponents to access large, high value international markets at a time of burgeoning demand and tight supply. In particular, the current oil price environment has flowed on to high prices for internationally traded LNG, which are linked formulaically to crude oil prices. With oil selling at around US$100 per barrel, the delivered price of LNG under current price arrangements can be expected to lie in the range of US$12 to $17 per GJ. After allowing for the cost of liquefaction, shipping and regasification, the netback[10] value of gas delivered to the LNG plant currently stands in excess of A$7.50 per GJ. At these prices, and based on proponent estimates of capital costs, ACIL Tasman analysis suggests that the economics of the current proposed LNG projects may well be comparable to conventional LNG projects, many of which are based on large offshore gas fields for which development costs continue to rise rapidly.

10 Netback value is the revenues from the sale of all products generated from one unit of oil/gas, less the costs associated with bringing that unit to market. The costs may include, but are not limited to, importing, transportation, production and refining costs, and royalty fees.

Whether or not any LNG proposals proceed to development, the fact that they offer a credible alternative market pathway for local gas suppliers means that they are starting to impact on domestic gas prices. Trends in pricing of domestic gas are discussed below.

Another significant issue arising from the proposed LNG developments relates to availability of gas for domestic use. A 4 million tonne per year LNG plant would require gas supply of between 225 and 250 PJ/a (after allowing for gas used in processing and transportation). In order to provide a 20-year reserve backing, such a development would therefore require dedication of up to 5000 PJ of proven and probable gas (2P) resources. Total 2P resources of CSG in eastern Australia currently stand at between 7000 and 8000 PJ. Given the rate of reserves built up over the past five years, there is every reason to believe that significantly more CSG reserves can be established. However, it is clear that the LNG proposals have the potential to divert very significant quantities of gas that might otherwise be available to domestic markets to exports. This does not necessarily mean that the domestic market will be left short of supply. However, it does mean that domestic supply will have to rely on higher-cost and less productive sources of CSG sooner than would be the case in the absence of the LNG projects, which in turn has implications for domestic gas prices.

Implications of increased pipeline interconnection

The rapid pace of development of the gas transmission pipeline system in Australia is illustrated in figure E.5. As the level of interconnection between regional markets has increased, a number of commercial and operational implications have become apparent. One important commercial opportunity afforded by interconnection of the transmission system is the potential for swap arrangements to reduce the need for physical transportation of gas. A swap involves the substitution of gas sources to meet the supply obligations under two separate contracts. So, for example, a producer with a contract to supply gas from its fields in central Australia to a customer in Brisbane might enter into a swap arrangement with a producer holding a contract to supply gas from its CSG fields in eastern Queensland to a customer in Sydney: the first producer diverts its supply to the Sydney customer, while the second producer supplies the Brisbane customer. A swap arrangement may be made between two different gas suppliers, or may be made by a single supplier within its portfolio of contracts (an internal swap). While physical interconnection of the two customer markets is not necessary for a swap to occur,[11] increased interconnection of markets increases the number of swap opportunities that can be pursued.

Swap arrangements are potentially valuable because they can minimise the amount of physical transportation required. Savings may also come from avoiding or delaying the need for construction of physical interconnections.

While swaps can increase market efficiency by minimising the physical transportation of gas, reduced payments for transportation of gas could ultimately impact on the viability of pipeline service operators and on new pipeline investment. In the extreme, a network could be envisaged in which little if any flow occurs across the system, which instead acts as a large pressure balancing vessel, with physical flow being confined largely to peripheral areas of the network. High levels of interconnection and an active swap market that minimises the need for physical transport of gas therefore imply a move toward a different system of paying for pipeline services, one with a greater focus on paying for the rights to inject or withdraw gas from the system, rather than paying for the right to transport gas through the system.

11 For example, Santos and Origin have in place a swap arrangement under which Origin meets supply obligations to Santos customers in Brisbane using eastern Queensland CSG, while Santos meets supply obligations to Origin's customers in Sydney with gas from the Moomba facility. This swap does not require physical pipeline interconnection between Queensland and New South Wales, and one of the benefits from the swap arrangement is that it allows the contract for supply into New South Wales to be settled without the need to build the dry gas connection between Ballera and Moomba. However, such interconnections ultimately increase the opportunities for swaps to occur.

Increased interconnection also raises issues in relation to system management and balancing. To date, these functions have been undertaken on an asset by asset basis by individual pipeline owners (in conjunction with system operators such as REMCo). However, with increasing integration and differing ownership across various sections of the network, the need for effective coordination between assets will become more apparent. Current initiatives to establish a bulletin board system and short-term trading market (see section E.2) are important steps in this direction.

The outlook for gas demand

Underlying gas demand in Australia could reasonably be expected to increase at an average of around 2.4 per cent per year—broadly in line with historical trends in the industry—driven by both demographic growth and industrial expansion. This would see domestic demand in eastern Australia rise from 680 PJ to 1070 PJ over the next 20 years. Similar growth in Western Australia (well below historical rates, but reflecting current tight supply and a higher price outlook) would raise domestic gas demand in the west from 350 PJ to 550 PJ by 2027.

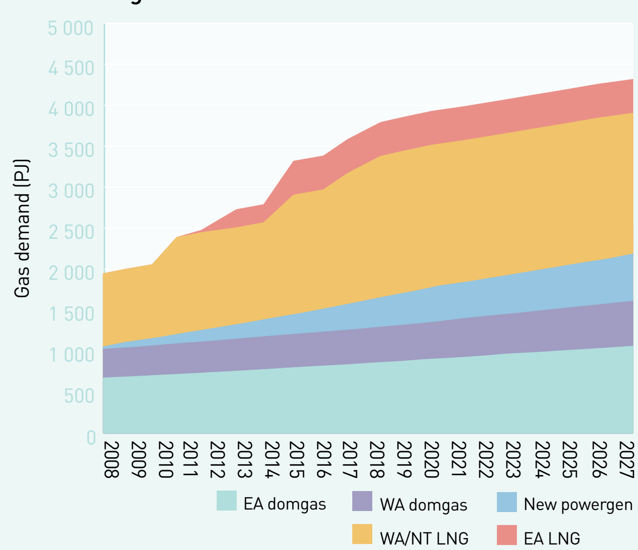
However, two factors have the potential to push total gas demand growth much more strongly:

- increased reliance on gas for power generation, driven by the expected introduction of a national emission trading regime within the next two to three years
- expansion of LNG production, including establishment of an east coast LNG industry based on CSG.

The introduction of emission trading, as part of a suite of policies aimed at reducing greenhouse gas emissions, will make gas-fired electricity generation more competitive. As a result, it is likely that combined-cycle gas turbine (CCGT) plant will be the preferred new-entrant technology for bulk electricity generation, at least until low emission coal-based technologies employing carbon capture and storage become commercially available —unlikely before 2020. The required capacity of new gas-fired plant to meet demand will depend on the price of carbon under emissions trading and other factors, such as the level of uptake of renewable technologies. For purposes of illustration, we have assumed that CCGT plant accounts for the majority of new base load generation plant in both eastern and Western Australia until 2020, and continues to meet half of demand growth as new low emission technologies are introduced. On this basis, the gas requirement for incremental power generation would add around 575 PJ to domestic gas demand by 2027.

Further demand growth will be driven by expansion of LNG production. A reasonable outlook would see LNG production capacity in Western Australia and the Northern Territory increase from 16.2 million tonnes per year at present to 31 million tonnes per year by 2027, boosting feed gas requirements from 900 PJ/a to more than 1700 PJ/a. LNG developments in eastern Australia based on CSG could potentially add a further 400 PJ/a to demand, based on the development of 7.5 million tonnes per year production capacity.

Figure E.9
Australian gas demand outlook



EA, eastern Australia; WA, Western Australia; NT, Northern Territory; domgas, domestic gas; new powergen, new power generation; LNG, liquefied natural gas
Source: ACIL Tasman estimates.

Figure E.9 summarises the growth outlook for Australian gas. It provides an indication of how overall demand could develop over the next 20 years, taking into account effects of emission trading and LNG expansion.

Under this view, total gas demand will more than double, to around 4300 PJ/a, by 2027.

There is, of course, considerable scope for variation in actual outcomes given the uncertainties surrounding carbon pricing and the size, timing and location of LNG developments. However, the analysis highlights the strong growth potential for the Australian gas market, driven by domestic policies as well as international opportunities.

The outlook for gas prices

Gas prices in Australia have historically been low by international standards. They have also been stable, defined by provisions in long-term supply contracts that reflect defined base prices periodically adjusted to reflect changes in a price index such as the CPI. Rarely have Australian domestic gas prices been linked to other commodities with a more volatile price, such as crude oil.

In this regard, the Australian market is quite different from many overseas markets, including the USA, UK, Europe and many Asian countries where gas prices closely follow oil prices. The principal reason for this difference is that in Australia, natural gas has generally been seen as a substitute for coal and coal-based electricity, rather than for oil or other petroleum products. Australia's abundant, low-cost coal sources have effectively capped gas prices, limiting the prices that large-scale users in power generation and industrial applications were willing and able to pay.

Through the early 2000s, wholesale domestic gas prices throughout Australia remained low. In southern Australia, prices generally moved in line with inflation. In Queensland, where the CSG industry was emerging and new producers were keen to establish market share, new supply contracts saw significant price discounting.

Over the past two years, a number of interacting factors have brought about a major shift in the outlook for prices:

- There has been sustained upward pressure on exploration and development costs. This trend is not confined to Australia, but has been observed around the world as a result of strong global demand and capacity constraints. It has been particularly evident in the offshore oil and gas sector where upstream development cost indicators have almost doubled since 2005.[12]
- High oil prices—now standing above US$100 per barrel—have flowed on to international gas prices, including to Australian LNG exports. This has accentuated the gap between international prices and Australian domestic prices. Producers in Western Australia have responded by focussing development efforts on higher value export markets and demanding steeply increased prices for incremental domestic supply. In eastern Australia, producers have sought to establish a nexus with international prices through proposed LNG developments. The credible threat of diversion of substantial volumes of CSG from domestic markets to LNG exports is now influencing both producer and consumer price expectations.
- Electricity prices rose sharply in eastern Australia during 2007 as drought impacted on some generators —and gas prices followed. While both electricity and spot gas prices have retreated with the easing of drought conditions and relaxation of other generation constraints, the demonstrated ability of the market to absorb higher gas prices will influence near-term price settlements.
- The anticipated introduction of a national emission trading scheme would make gas a more valuable commodity in the future. Both producers and consumers are now factoring this higher anticipated demand and value into the pricing of long-term contracts that will bridge into the period when emissions trading is in place.

12 Cambridge Energy Research Associates, Upstream Capital Costs Index.

- Domestic coal prices are under sustained upward pressure as a result of the renegotiation of contracts for supply to Queensland and New South Wales generators at a time when international coal prices are very high and the range of coal qualities now being traded internationally is much wider than in the past. Higher coal prices effectively raise the cap on domestic gas prices.

The net result of these influences is that domestic gas prices are now rising. In the absence of any transparent spot market outside Victoria, and given that most prices continue to be settled in the context of long-term supply contracts, it is difficult to say exactly how far prices have risen. However, there is anecdotal evidence that in Western Australia recent sales of gas (in limited quantities, and generally to consumers in remote locations) have been settled for prices above $7 per GJ: around three times higher than the prevailing wholesale price prior to the onset of supply constraints. ACIL Tasman understands that buyers in Queensland looking to secure new gas supplies are now finding that producers are seeking significantly higher prices, reportedly in excess of $4 per GJ.

The fact that most of the major CSG producers are currently looking to boost reserves and production capacity to underpin proposed LNG facilities means that the supply surplus which had prevailed in the Queensland market for several years has now been reversed.

Higher gas prices will, of course, encourage supply side responses from new entrant producers as well as alternative energy sources. ACIL Tasman does not expect to see a sustained move, in either eastern or Western Australia, to full export parity pricing of gas. On the other hand, we consider it likely that the drivers now in play will see gas prices rise in real terms with no current prospect of a reversion to former levels.

E.4 Conclusions

Over the past 10 years, there have been profound changes in the Australian gas market across a number of dimensions. The decade has been marked by fundamental industry restructuring through privatisation of previously government-owned assets, while corporate mergers and acquisitions have seen shifting ownership and control across the supply chain. Regulatory reform has reshaped the industry. Ongoing investment in upstream exploration and production and in midstream transport infrastructure has given rise to the emergence of a much more competitive market, with greater interconnection and diversification of options for gas buyers and sellers.

While the past decade has seen profound changes in the industry, the next decade promises even greater changes. Ongoing regulatory reforms, including the development of new spot trading markets, will continue to promote competition and greater transparency in the market. This will, in turn, encourage a deeper and more liquid gas market. Meeting the challenge of climate change and emission abatement will place greater demands on gas as a cleaner source of energy for power generation and industrial purposes. Increased demand will create great opportunities, as well as pose commercial and technical challenges, for producers. Under reasonable demand projections, consumption of gas for domestic and export use will more than double over the next 20 years. This will require further investment in transport infrastructure and in facilities for peaking capacity and gas storage to manage short-term flexibility requirements.

With the introduction of emission trading in 2010 and increased integration into global energy markets, the price of gas in Australia will more closely reflect its intrinsic value as a cleaner fuel as well as its potential alternative applications, both domestically and internationally.