
Origin Energy

3 UPSTREAM GAS MARKETS

The two main types of gas in Australia are conventional natural gas and coal seam gas (CSG). Conventional natural gas is found trapped in underground reservoirs, often along with oil. In contrast, CSG is a form of gas extracted from coal beds. There are also renewable gas sources, such as biogas (landfill and sewage gas) and biomass (wood, wood waste and sugarcane residue). The potential for shale gas is being explored in the Cooper Basin.[1]

Gas is produced both for domestic markets and for export as liquefied natural gas (LNG). The supply chain begins with exploration and development activity, which may involve geological surveys and the drilling of wells (figure 3.1). In the commercialisation phase, extracted gas is processed to separate methane from liquids and other gases that may be present, and to remove any impurities.

In the domestic market, high pressure transmission pipelines transport gas from gas fields to demand hubs. A network of distribution pipelines then delivers gas from points along transmission pipelines to industrial customers, and from gate stations (or city gates) to consumers in cities, towns and regional communities. Gate stations measure the gas leaving a transmission system for billing and gas balancing purposes, and reduce the pressure of the gas before it enters a distribution network. Energy retailers complete the supply chain; they buy gas in wholesale markets and package it with pipeline transportation services for sale to customers.

This chapter covers gas production and wholesale market arrangements. While it focuses on domestic markets in eastern Australia in which the Australian Energy Regulator (AER) has regulatory responsibilities,[2] it has some coverage of upstream gas markets in Western Australia and the Northern Territory, and LNG export markets.

Chapter 4 considers the transmission and distribution pipeline sectors; chapter 5 covers the retailing of gas to small customers.

1 Shale gas is contained within organic-rich rocks such as shale and fine grained carbonates, rather than in underground reservoirs. The application of horizontal drilling techniques in the past five years is enhancing the economic viability of shale gas development.

2 The AER has compliance and enforcement responsibilities (under parts 18–20 of the National Gas Rules) in relation to the Natural Gas Market Bulletin Board, the Victorian wholesale gas market and the short term trading market that commenced operating in Sydney and Adelaide in 2010, and in Brisbane in December 2011.

3.1 Gas reserves and production

In August 2012 Australia's proved and probable (2P) gas reserves stood at around 140 000 petajoules (PJ), comprising 98 000 PJ of conventional natural gas and 42 000 PJ of CSG (table 3.1 and figure 3.2).

Total 2P reserves increased by around 21 per cent in 2011–12, mainly due to the upgrading of Browse Basin reserves in Western Australia to 2P status. Excluding this change, 2P reserves rose nationally by 6 per cent in 2011–12. CSG reserves in Queensland and New South Wales rose by 10 per cent.

Australia produced 1924 PJ of gas in 2011–12, of which around 55 per cent was for the domestic market. Production for domestic use was down 1.4 per cent from levels in 2010–11. The CSG share of production for domestic use rose from 21 per cent in 2010–11 to 23 per cent in 2011–12. Around 45 per cent of Australia's gas production—all currently sourced from offshore basins in Western Australia and the Northern Territory—is exported as LNG. This ratio will increase, with the development of major LNG projects in Queensland and Western Australia (section 3.2.1).

3.1.1 Geographic distribution

Western Australia's offshore Carnarvon Basin holds about half of Australia's 2P gas reserves. It supplies almost one third of Australia's domestic market and 99 per cent of Australian gas for LNG export.[3]

The Bonaparte Basin along the north west coast contains 1 per cent of Australia's gas reserves. While the basin's development has focused on producing LNG for export (which began in 2006), the Bonaparte Pipeline was commissioned in 2008 to ship gas to the Northern Territory for domestic consumption. The basin has now displaced the Amadeus Basin as the main source of gas for the Northern Territory.

Eastern Australia contains around 35 per cent of Australia's gas reserves, of which the majority are CSG reserves in the Surat–Bowen Basin. The basin, which extends from Queensland into northern New South Wales, accounts for 80 per cent of gas reserves in eastern Australia and supplies 35 per cent of that market. In New South Wales, commercial production of CSG began in 1996 in the Sydney Basin and more recently in the Gunnedah Basin. CSG production in eastern Australia rose by 7 per cent to 247 PJ in 2011–12,

3 Data on gas production, consumption and reserves are sourced from EnergyQuest, *Energy Quarterly*, August 2012.

Figure 3.1
Domestic gas supply chain

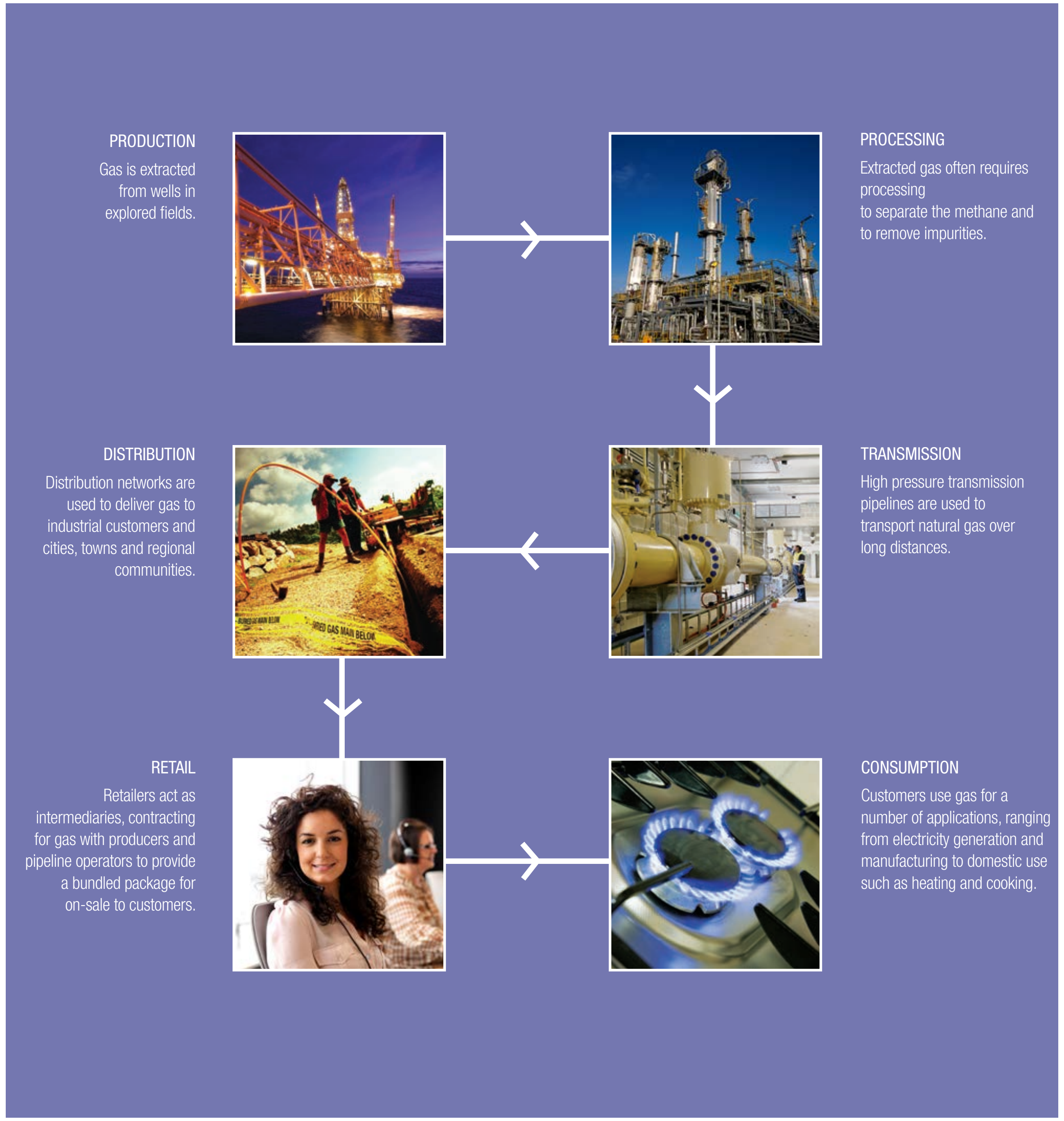
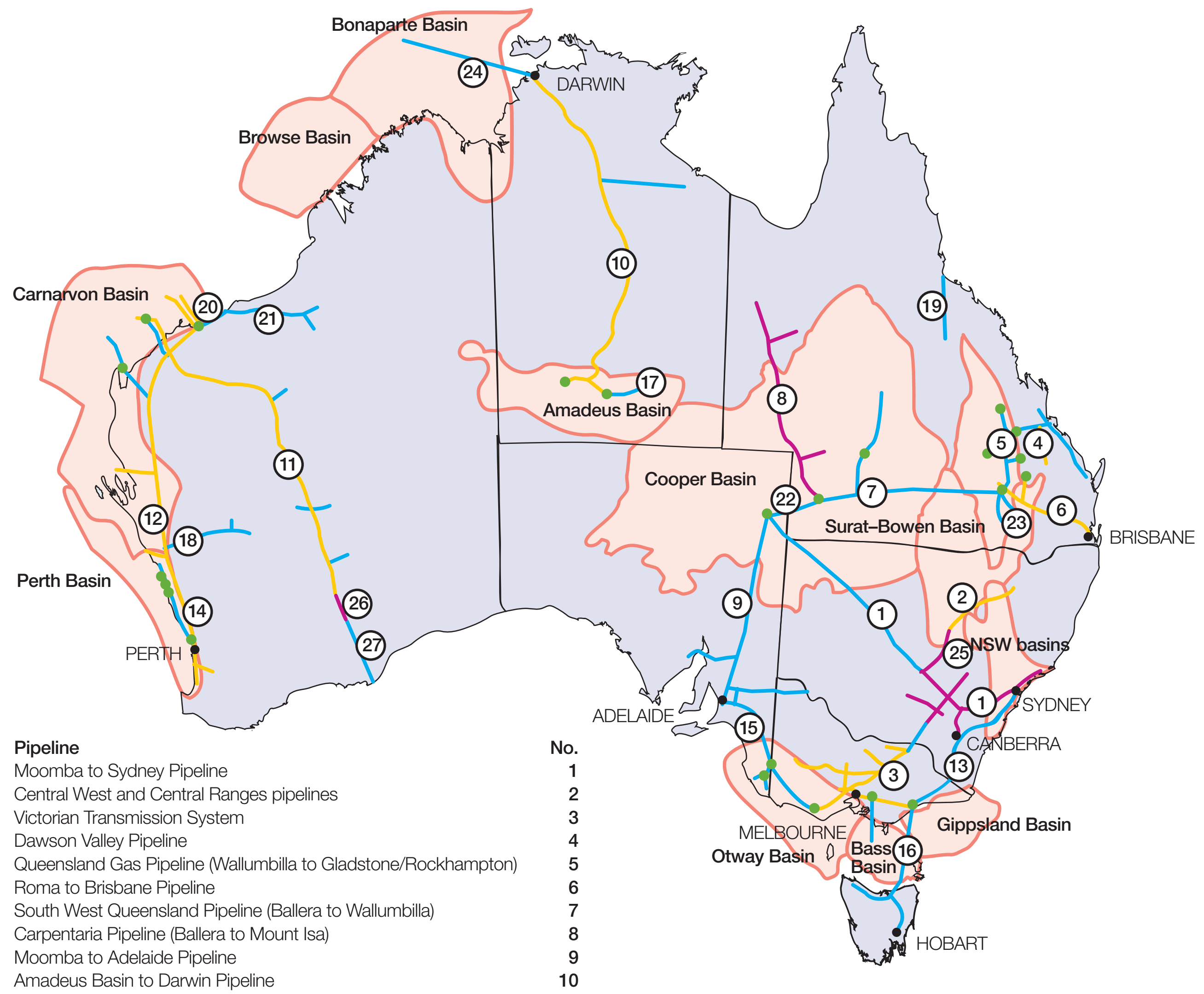
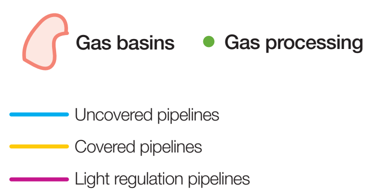


Image Sources: Origin Energy, Woodside, Jemena.

Figure 3.2
Australian gas basins and transmission pipelines





Pipeline	No.
Moomba to Sydney Pipeline	1
Central West and Central Ranges pipelines	2
Victorian Transmission System	3
Dawson Valley Pipeline	4
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Carpentaria Pipeline (Ballera to Mount Isa)	8
Moomba to Adelaide Pipeline	9
Amadeus Basin to Darwin Pipeline	10
Goldfields Gas Pipeline	11
Dampier to Bunbury Natural Gas Pipeline	12
Eastern Gas Pipeline (Longford to Horsley Park)	13
Parmelia Pipeline	14
SEA Gas Pipeline	15
Tasmanian Gas Pipeline	16
Palm Valley to Alice Springs Pipeline	17
Midwest Pipeline	18
North Queensland Gas Pipeline	19
Pilbara Pipeline	20
Telfer Pipeline	21
QSN Link	22
Berwyndale to Wallumbilla Pipeline	23
Bonaparte Pipeline	24
Central West Pipeline	25
Kalgoorlie to Kambalda Pipeline	26
Kambalda to Esperence Pipeline	27

Source: AER.

Table 3.1 Gas reserves and production, 2012

	PRODUCTION (YEAR TO JUNE 2012)		PROVED AND PROBABLE RESERVES[1] (AUGUST 2012)	
GAS BASIN	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS				
WESTERN AUSTRALIA				
Browse	0	0.0	17 384	12.4
Carnarvon	342	32.1	72 456	51.8
Perth	5	0.5	41	0.0
NORTHERN TERRITORY				
Amadeus	1	0.1	138	0.1
Bonaparte	20	1.9	1 123	0.8
EASTERN AUSTRALIA				
Cooper (South Australia–Queensland)	95	8.9	1 740	1.2
Gippsland (Victoria)	244	22.8	4 124	2.9
Otway (Victoria)	102	9.6	847	0.6
Bass (Victoria)	8	0.8	249	0.2
Surat–Bowen (Queensland)	4	0.4	147	0.1
Total conventional natural gas	820	76.9	98 249	70.2
COAL SEAM GAS				
Surat–Bowen (Queensland)	241	22.6	38 918	27.8
New South Wales basins	6	0.5	2 827	2.0
Total coal seam gas	247	23.1	41 745	29.8
AUSTRALIAN TOTALS	1 067	100.0	139 994	100.0
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	846			
Bonaparte (Northern Territory)	12			
Total liquefied natural gas	857			
TOTAL PRODUCTION	1 924			

1. Proved reserves are those for which geological and engineering analysis suggests at least a 90 per cent probability of commercial recovery. Probable reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery.

Source: EnergyQuest, *Energy Quarterly*, August 2012.

in contrast to an overall decline of 6 per cent in east coast conventional gas production.

The Gippsland Basin off coastal Victoria supplies 35 per cent of the eastern market. Production in Victoria's offshore Otway Basin (15 per cent of eastern production) has risen significantly since 2004, but declined by 4 per cent in 2011–12.

After several years of decline, Cooper Basin reserves in central Australia rose in the past two years, up 27 per cent in the year to June 2012. Production in the basin may continue to rise in the future, with new activity focused on the development of shale gas.[4]

4 In August 2012 Santos announced Australia's first commercially viable gas drawn from fractured shale rock at Moomba.

3.2 Gas demand

Australia consumed 1067 PJ of gas in 2011–12 (down slightly from 1082 PJ in 2010–11) for industrial, commercial and domestic use. The consumption profile varies across the jurisdictions.

While gas is widely used in most jurisdictions for industrial manufacturing, a key driver of domestic gas demand over the next 20 years is likely to be in gas powered electricity generation (section 3.5.1). Western Australia, South Australia, Queensland and the Northern Territory especially rely on gas for electricity generation. In Western Australia, the mining sector is also a major user of gas. Household demand is relatively small, except in Victoria, where residential demand accounts for around one third of total consumption. This proportion reflects the widespread use of gas for cooking and heating in that state.

3.2.1 Liquefied natural gas exports

The production of LNG converts gas into liquid. The development of an LNG export facility requires large upfront capital investment in processing plant, port and shipping facilities. The magnitude of investment requires access to substantial reserves of gas, which may be sourced through the owner's interests in gas fields, a joint venture arrangement with a gas producer, or long term gas supply contracts.

Australia operates LNG export projects in Western Australia's North West Shelf and Darwin, and is developing new projects in Queensland. While exports of Australian produced LNG decreased in 2011–12 by 9 per cent (to 15.6 million tonnes),[5] major players are continuing to expand capacity:

- Woodside's 4.3 million tonne per year Pluto project (Carnarvon Basin) is completed and began exporting LNG in May 2012. It became Australia's third operational LNG project. The estimated development cost was $14.9 billion.
- Chevron's Gorgon project (Carnarvon Basin) is scheduled to begin operation in 2014 and will produce around 15.6 million tonnes of LNG per year. The project partners have signed long term sales agreements with international buyers. EnergyQuest reported the project was over 45 per cent complete in June 2012. In addition, Chevron committed to the $29 billion Wheatstone project (foundation capacity of 8.9 million tonnes per year) in September 2011. The project is expected to produce its first LNG in 2016.
- Shell's $10–$13 billion Prelude floating LNG project (Browse Basin) is under construction and expected to commence production in 2017. The project will produce 3.6 million tonnes per year.
- Construction of Inpex and Total's $34 billion Ichthys LNG project (Browse Basin) commenced in May 2012. The project is expected to produce 8.4 million tonnes of LNG and 1.6 million tonnes of liquefied petroleum gas annually, with production expected to begin in 2017.
- The Browse LNG project—Woodside (operator) 31 per cent, Shell 27 per cent, BP 17 per cent, MIMI 14.7 per cent and BHP Billiton 10 per cent—reached the front end engineering and design (FEED) stage in 2012. The project is expected to produce 12 million tonnes per year.

5 LNG production and export data are sourced from EnergyQuest, *Energy Quarterly*, August 2011, p. 24.

In Queensland, long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, have spurred the development of several LNG projects near the port of Gladstone. Construction of three projects, including three gas transmission pipelines to transport gas to Gladstone, is underway:

- The $20 billion Curtis LNG project (BG Group) will initially produce 8.5 million tonnes per year, with potential capacity of 12 million tonnes. The first exports are expected in 2014.
- The $18.5 billion Gladstone LNG project (Santos, Petronas, Total and Kogas) will initially produce 7.8 million tonnes per year, with potential capacity of 10 million tonnes. The first exports are expected in 2015.
- The proponents of the Australia Pacific LNG project (Origin Energy, ConocoPhillips and Sinopec) announced the approval of a second 4.5 million tonne per year production train, increasing total capability to 9.0 million tonnes annually. Construction on the first train commenced in May 2011, and first LNG exports are expected in 2015. Exports from the second train are expected to commence in 2016. The cost of the two trains is estimated at $23 billion.

A fourth project—Arrow LNG project (Shell and PetroChina)—is at the planning stage. It will produce up to 18 million tonnes per year, with first exports expected in 2017. With Queensland LNG projects coming onstream from around 2014–15, Australia would likely become the world's second largest exporter of LNG.[6]

3.3 Industry structure

Six major producers met 65 per cent of domestic gas demand in 2011–12: Santos, BHP Billiton, ExxonMobil, Origin Energy, Woodside and Apache Energy.[7] The mix of players varies across the basins.

3.3.1 Market concentration

Market concentration in particular gas basins depends on multiple factors, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Figure 3.4 illustrates

6 Bureau of Resources and Energy Economics (BREE), *Gas market report*, July 2012, p. 1.

7 EnergyQuest, *Energy Quarterly*, August 2012.

estimated market shares in gas production for the domestic market in the major basins. Table 3.2 sets out market shares in 2P gas reserves (including reserves available for export) at August 2012.

Several major companies have equity in Western Australia's Carnarvon Basin, which is Australia's largest producing basin. The businesses participate in joint ventures, typically with overlapping ownership interests. Chevron (37 per cent), Shell (17 per cent) and ExxonMobil (14 per cent) have the largest reserves in the basin, given their equity in the Gorgon project.

Browse Basin reserves are included in table 3.2 for the first time, following their upgrading to 2P status. Inpex (55 per cent), Total (23 per cent) and Shell (15 per cent) are the major players in that basin.

Woodside (25 per cent) and Apache Energy (24 per cent) are the largest producers for Western Australia's domestic market. Santos (17 per cent), BP and Chevron (10 per cent each), and BHP Billiton and Shell (6 per cent each) also have significant market shares.

The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea. Eni Australia owns over 80 per cent of Australian reserves in the basin.

In central Australia, a joint venture led by Santos (63 per cent) dominates production in the Cooper Basin. The other participants are Beach Petroleum (22 per cent) and Origin Energy (14 per cent).

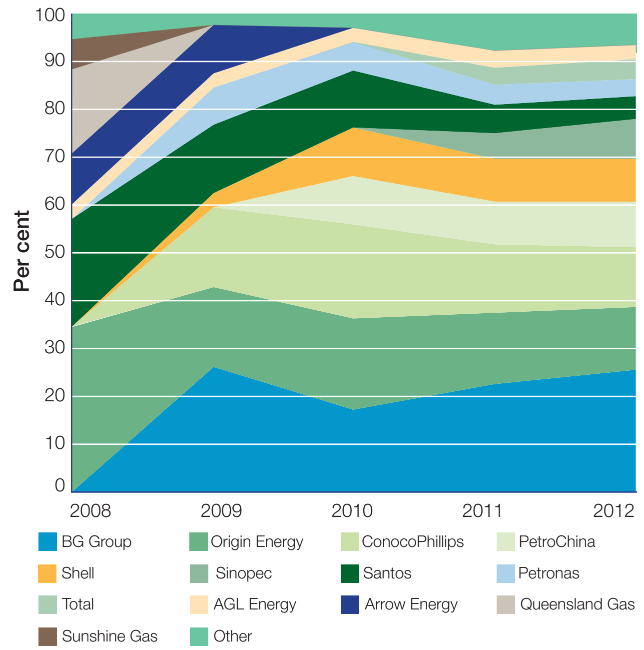
The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and provide gas to New South Wales, South Australia and Tasmania. A joint venture between ExxonMobil and BHP Billiton accounts for around 93 per cent of production in the Gippsland Basin. Nexus, which began production from the Longtom gas project in October 2009, acquired a 7 per cent market share.

The Otway Basin has a more diverse ownership base, with Origin Energy (32 per cent), BHP Billiton (19 per cent) and Santos (18 per cent) accounting for the bulk of production. The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration (AWE).

The growth of the CSG–LNG industry has led to considerable new entry in Queensland's Surat–Bowen Basin over the past decade. The largest producers are BG Group (21 per cent), Origin Energy (20 per cent), ConocoPhillips (19 per cent), Santos (9 per cent), Sinopec, Shell and PetroChina (6 per cent each). Petronas, Total and AGL Energy have smaller shares. The same businesses also own the majority of reserves in the basin.

Figure 3.3 shows changes in market shares of gas reserves in the Surat–Bowen Basin between 2008 and 2012. The changes reflect mergers and acquisitions, and the development of new projects. In 2008 three entities owned 75 per cent of reserves (Origin Energy 35 per cent, Santos 22 per cent and Queensland Gas 18 per cent). In contrast, the three largest players in 2012 jointly own 52 per cent of reserves (BG Group 26 per cent and Origin Energy and ConocoPhillips each 13 per cent).

Figure 3.3
Market shares in proved and probable reserves, Surat–Bowen Basin, 2008–12



Data source: EnergyQuest 2008–12 (unpublished data).

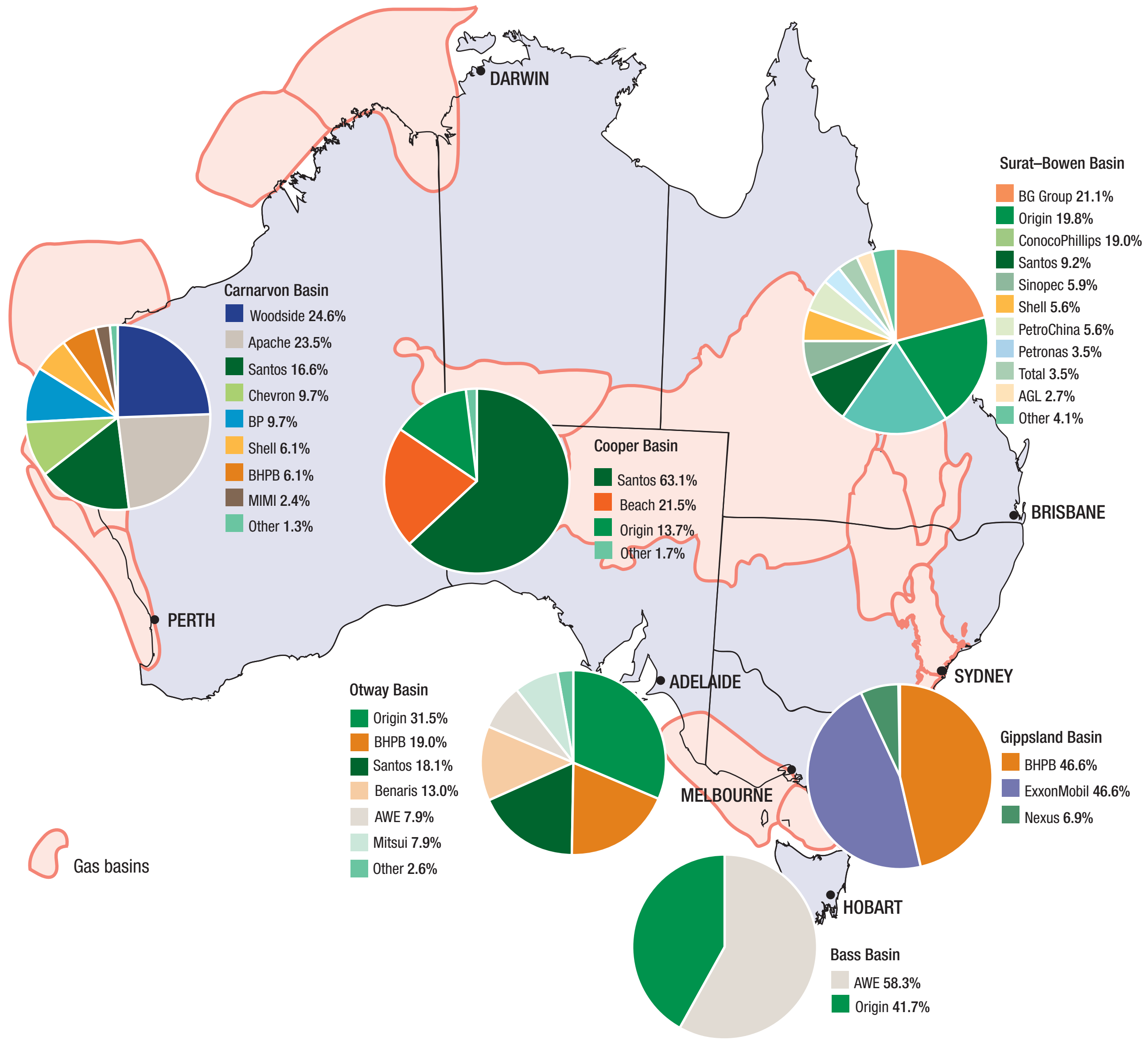
3.3.2 Mergers and acquisitions

Merger and acquisition activity in upstream gas since 2006 has focused mainly on CSG (and associated LNG proposals) in Queensland and New South Wales. Previous editions of the AER's *State of the energy market* report listed proposed and successful acquisitions from June 2006 to October 2011. Subsequent activity until October 2012 included the following:

- In January 2012 Arrow Energy (Shell and PetroChina) completed its acquisition of Bow Energy, to source additional CSG resources for its Queensland LNG project.

Figure 3.4

Market shares in domestic gas production, by basin, 2011–12



Note: Excludes LNG.

Data source: EnergyQuest 2012 (unpublished data).

Table 3.2 Market shares in proved and probable gas reserves, by basin, 2012 (per cent)

COMPANY	CARNARVON (WA)	BROWSE (WA)	PERTH (WA)	BONAPARTE (WA/NT)	AMADEUS (NT)	SURAT-BOWEN (QLD)	COOPER (SA/QLD)	CLARENCE MORTON (QLD/NSW)	GUNNEDAH (NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	HUNTER (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Chevron	36.9															19.1
Shell	17.2	14.8				8.9										13.2
ExxonMobil	14.1												45.7			8.6
BG						25.6										7.1
Inpex		55.4		2.1												6.9
Woodside	11.4															5.9
Origin			63.7			13.0	12.9							37.1	42.5	4.1
Total		23.4				3.7										3.9
Santos	1.1			2.1	89.2	4.6	64.3		80.0				5.3	16.6		3.8
ConocoPhillips				10.4		12.6										3.6
BHPB	3.8												45.7	15.2		3.4
PetroChina						9.8										2.7
Sinopec						8.4										2.3
BP	4.2															2.2
Apache	3.6															1.9
MIMI	3.1															1.6
AGL						3.1				100.0	100.0	100.0				1.5
Petronas						3.7										1.0
CNOOC	1.1					1.2										0.9
Kogas		2.2				2.0										0.8
Eni				83.8												0.7
Kufpec	1.1															0.6
Osaka Gas	0.7	0.9														0.5
Mitsui						1.1								6.5		0.3
Metgasco								96.2								0.3
Beach							20.3							0.1		0.3
EnergyAustralia									20.0							0.2
Kansai Electric	0.4															0.2
Toyota Tsusho						0.5								2.8	11.3	0.2
Nexus													3.3			0.1
Benaris														15.3		0.1
AWE			36.3											6.5	46.3	0.1
Other	1.3	3.3		1.6	10.8	1.8	2.5	3.8								1.7
TOTAL (PETAJOULES)	72 456	17 384	41	1123	138	39 055	1758	445	1426	669	142	142	4124	847	249	139 998

Notes:

Based on 2P reserves at August 2012.

Not all minority owners are listed.

Source: EnergyQuest 2012 (unpublished data).

- In March 2012 AWE sold a share of its interest in the Bass Basin to Toyota Tsusho for $80 million. The transaction gives Toyota Tsusho an 11 per cent share in the reserves of that basin.
- In July 2012 Sinopec increased its stake in the Australia Pacific LNG project from 15 per cent to 25 per cent. Origin Energy and ConocoPhillips each hold a 37.5 per cent stake in the project.

3.3.3 Vertical integration

Vertical integration between gas production, gas powered generation and energy retailing is a means by which energy entities manage risk and achieve efficiencies. For example:

- Origin Energy is a leading energy retailer and is expanding its gas powered generation portfolio in eastern Australia. It has significant equity in CSG production in Queensland and in conventional natural gas production in Victoria's Otway and Bass basins, and a minority interest in gas production in the Cooper Basin. It accounted for 14 per cent of gas production in eastern Australia in 2011–12.
- AGL Energy is a leading energy retailer and a major electricity generator in eastern Australia. It began acquiring CSG interests in Queensland and New South Wales in 2005.

EnergyAustralia (formerly TRUenergy), a third major retailer and generator in eastern Australia, has gas storage facilities in Victoria and acquired gas reserves in the Gunnedah Basin (New South Wales) in 2011.

3.4 Gas wholesale markets

Gas producers sell gas in wholesale markets to major industrial, mining and power generation customers, and to energy retailers that onsell it to business and residential customers. While gas prices were historically struck under confidential, long term contracts, there has been a recent shift towards shorter term contracts and the emergence of spot markets. Victoria established a wholesale spot market in 1999 for gas sales, to manage system imbalances and pipeline network constraints. More recently, governments and industry established the National Gas Market Bulletin Board and a short term trading market in major hubs in eastern Australia.

3.4.1 Short term trading market

A short term trading market—a wholesale spot market for gas—has been progressively implemented at selected hubs (junctions) linking transmission pipelines and distribution systems in eastern Australia. The Australian Energy Market Operator (AEMO) operates the market, which was designed to enhance gas market transparency and competition by setting prices based on supply and demand conditions.[8] The AER monitors and enforces compliance with the market Rules (section 3.6).

The market was launched in September 2010 in Sydney and Adelaide, and was extended to Brisbane in December 2011. Each hub is scheduled and settled separately, but all hubs operate under the same Rules. Victoria retains a separate spot market for gas (section 3.4.2).

The short term trading market provides a spot mechanism for parties to manage contractual imbalances. It also provides a platform for secondary trading and demand side response by users. *Shippers* deliver gas to be sold in the market, and *users* buy gas for delivery to customers. Market participants include energy retailers, power generators and other large scale gas users. The same entity might sell gas into the market (if it has more gas than it requires) and also buy from the market (if it requires additional gas to meet demand).

Gas is traded a day ahead of the actual gas day, and AEMO sets a day-ahead (ex ante) clearing price at each hub, based on scheduled withdrawals and offers by shippers to deliver gas. All gas supplied according to the market schedule is settled at this price. The market provides incentives for participants to keep to their schedules, and the Rules require the participants bid in 'good faith'.

Based on the market schedule, shippers nominate the quantity of gas they require from a pipeline operator, which develops a separate schedule for that pipeline to ensure it is kept in physical balance. On the gas day, quantities delivered to and withdrawn from a hub may not match the day-ahead nominations, due to variations in demand and other factors. As gas requirements become better known during the day, shippers may renominate quantities (intraday nominations) with pipeline operators (depending on the terms of their contracts).

Pipeline operators use balancing gas to keep the pipeline in physical balance. AEMO procures this balancing gas—market operator service (MOS)—from shippers that have the capacity to absorb daily fluctuations, and the short term trading market sets a price for it. Gas procured under this balancing mechanism is settled primarily through deviation payments and charges on the parties responsible for the imbalances (section 3.6.1).

Section 3.5.2 notes recent price activity in the short term trading market. The market has a floor price of $0 per gigajoule and a cap of $400 per gigajoule.

8 AEMO publishes an explanatory guide on its website: AEMO, *Overview of the short term trading market for natural gas,* 2011.

3.4.2 Victoria's gas wholesale market

Victoria's spot market for gas was introduced to manage gas flows on the Victorian Transmission System and allow market participants to buy and sell gas at a spot price. Market participants submit daily bids ranging from $0 per gigajoule (the floor price) to $800 per gigajoule (the price cap). Following initial bidding at the beginning of the gas day (6 am), the bids may be revised at the scheduling intervals of 10 am, 2 pm, 6 pm and 10 pm.

At the beginning of each day, AEMO stacks supply offers and selects the least cost bids to match demand across the market. This process establishes a spot market clearing price. Given Victoria has a net market, the price applies to only net positions—that is, the difference between a participant's scheduled gas deliveries into and out of the market. AEMO can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term constraints.[9]

Typically, gas traded at the spot price accounts for 10–20 per cent of wholesale volumes in Victoria, after accounting for net positions. The balance of gas is sourced via bilateral contracts or vertical ownership arrangements between producers and retailers. Section 3.5.2 notes recent price activity.

The Victorian gas market and short term trading market have differences in design and operation:

- In the short term trading market, AEMO operates the financial market but does not manage physical balancing (which remains the responsibility of pipeline operators). In the Victorian market, AEMO undertakes both roles.
- The Victorian market is for gas only, while prices in the short term trading market cover gas as well as transmission pipeline delivery to the hub.

9 AEMO publishes an explanatory guide on its website: AEMO, *Guide to Victoria's declared wholesale market*, 2012.

3.4.3 National Gas Market Bulletin Board

The National Gas Market Bulletin Board, which commenced in July 2008, is a website (www.gasbb.com.au) covering major gas production plants, storage facilities, demand centres and transmission pipelines in eastern Australia. There is provision for facilities in Western Australia and the Northern Territory to participate in the future.

The bulletin board aims to provide transparent, real-time information on the state of the gas market, system constraints and market opportunities. It covers:

- gas pipeline capabilities (maximum daily volumes) and three day outlooks for capacity and volume, and actual gas volumes
- production capabilities (maximum daily quantities) and three day outlooks for production facilities
- pipeline storage (linepack) and three day outlooks for gas storage facilities
- daily demand forecasts, changes in supply capacity, and the management of gas emergencies and system constraints.

Bulletin board participants must provide the information, and the AER monitors and enforces compliance with the relevant Rules (section 3.6). AEMO operates the bulletin board; it also publishes an annual gas statement of opportunities to help industry participants plan and make commercial decisions on infrastructure investment.

3.4.4 Gas trading hub market—Queensland

In light of escalating gas development in south east Queensland, the Standing Council on Energy and Resources (SCER, formerly the Ministerial Council on Energy) in 2012 commissioned work on the possible design of a gas trading market at Wallumbilla in Queensland. The hub is a major pipeline interconnection point for the Surat–Bowen Basin.

The proposed model is for a 'brokerage' hub, or exchange, to match and clear trades using existing physical infrastructure. Given physical limitations within the Wallumbilla hub, separate trading nodes would be created for each of the major pipelines connected to the hub. The introduction of services to assist gas trading between nodes may follow. The market model is intended to be capable of replication in other locations.

SCER expected to consider the matter further in December 2012, with a view to launching the market from early 2014. Participation in the market would be voluntary.

3.5 Eastern Australia gas prices and market outlook

Australian gas prices have generally been low by international standards, typically $3–4 per gigajoule. They have also been relatively stable, defined by provisions in long term supply contracts. With gas in Australia historically perceived as a substitute for coal and coal fired electricity generation, Australia's low cost coal sources have effectively capped gas prices.

The growth of LNG export capacity in Western Australia from the late 1980s led to that state's domestic market being increasingly exposed to international energy prices. A similar scenario may be unfolding in eastern Australia, with LNG exports expected to commence from Queensland in 2014–15.

3.5.1 Market conditions

While EnergyQuest reported east coast gas prices under existing contracts remained steady in 2011–12 at around $4 per gigajoule, prices struck under new contracts rose to over $5 per gigajoule.[10] In spot markets, prices rose sharply in winter 2012 to over $6 per gigajoule (and exceeded $7 per gigajoule in all hubs on some days).

An interaction of several factors affects gas markets and price outcomes in eastern Australia. On the supply side, rising CSG production and improved pipeline interconnection among gas basins have made markets more responsive to customer demand. An interconnected transmission pipeline network in eastern Australia now enables gas producers in the Surat–Bowen, Cooper, Gippsland, Otway, Bass and New South Wales basins to sell gas to customers across Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT).

While gas demand in eastern Australia fell by 1.7 per cent in 2011–12,[11] two factors are expected to stimulate growth in the next 20 years: gas powered electricity generation and LNG exports from Queensland.

Gas powered electricity generation currently represents around 24 per cent of domestic gas demand in eastern Australia.[12] The Bureau of Resource and Energy Economics and ACIL Tasman noted in 2012 that carbon pricing would increase the competitiveness of gas powered generation relative to coal, making electricity generation a key growth source for domestic gas demand over the next two decades in eastern Australia.[13] But the recent weakening in electricity demand and gas price uncertainty may slow the growth in gas powered generation.

The *Queensland gas market review 2012* projected relatively modest growth in gas powered generation in the state to 2020, but significant growth beyond that time. It considered emerging difficulties in securing domestic gas contracts (due to competing LNG demand) may dampen new investment in gas powered generation.[14]

AEMO modelled in late 2012 that the stimulus from the RET to wind generation, combined with weaker projected energy demand, may delay the need for generation investment for several years; it forecast gas powered generation may not rise significantly until 2025.[15]

While LNG exports from Queensland are not expected to begin until 2014, the project developers are continuing to secure reserves to underpin supply contracts with overseas customers. This trend is starting to put pressure on domestic gas availability and prices. The 2012 Queensland review noted east coast prices are increasingly based on export opportunity value; domestic users are now competing with LNG when contracting for supply. The report also noted liquidity issues in the Queensland market, with gas in short supply for new contracts both pre- and post-2015. More generally, customers seeking new domestic supply contracts for gas post-2015 are facing a lack of basic market information (forward prices, volumes available and potential delivery timeframes) for contracting.[16] The Australian Government's *Energy White Paper 2012* considered the market is currently not providing efficient platforms for contracting, and that such arrangements may take some time to emerge.[17]

The development of LNG projects in Queensland was widely expected in 2011 to produce large quantities of 'ramp-up' gas that would be available to domestic markets at relatively low prices until the projects were commissioned. Contrary to these expectations, the 2012 Queensland review noted the domestic sale of ramp-up gas prior to the commencement of LNG exports may not materialise. It noted in the current market environment, some proponents may be stockpiling reserves to preserve options for further LNG train development. The report also noted evidence of a new trend for LNG proponents to enter contracts with one another, including gas swaps. Its modelling found all four LNG projects would likely experience a shortfall in their required gas reserves at some stage in the period to 2030 and would need to source gas from the broader market.[18]

EnergyQuest agreed ramp-up gas would be less than previously expected, noting none of the projects appears to be achieving their drilling targets. The Bureau of Resources and Energy Economics noted landowners' concerns about the impact of CSG extraction on water resources have led to restrictions on drilling and tighter regulatory controls on land access.[19] EnergyQuest estimated in August 2012 that the Queensland LNG projects currently have 20–25 per cent deliverability necessary for their first LNG and other commitments.[20]

Aside from developments in Queensland, other factors are affecting east coast gas markets. EnergyQuest noted a lack of recent exploration success in offshore Victoria.[21] In New South Wales, complex regulatory hurdles have hampered the development of CSG resources in the Gunnedah and Gloucester basins.[22] Goldman Sachs noted policy uncertainty had effectively stalled gas development in that state for almost two years.[23] The New South Wales Government released its Strategic Regional Land Use Policy in September 2012, clarifying the regulatory regime for exploration and future development of the state's CSG resources.

Also, long term contract replacement is an ongoing issue; historical low priced domestic gas contracts will progressively expire over the next five years. Contract replacement activity is expected to peak in Queensland in 2015–16, and in New South Wales and Victoria in 2018. The expiration of low priced contracts and their renegotiation in a market exposed to global prices will continue to place pressure on domestic prices.[24]

Together, these factors are causing uncertainty in eastern gas markets and impacting on prices. The Bureau of Resources and Energy Economics predicts eastern gas wholesale prices will rise sharply in the short to medium term, converging towards global prices in anticipation of LNG exports from 2014–15.[25] ACIL Tasman projects gas prices for southern Queensland will remain higher than elsewhere in eastern Australia through to at least 2020, reaching around $9.40 per gigajoule by that time. It projected Victorian prices would be the lowest in eastern Australia, at around $7.70 per gigajoule in 2020.[26] Goldman Sachs expected New South Wales prices to link closely with those in Queensland.[27]

The 2012 Queensland review predicted Queensland domestic gas prices could rise to $6.50–10 per gigajoule by 2015 (depending on international energy market conditions). It predicted domestic prices of $7–$12 per gigajoule in 2020. The review's modelling indicated a widening divergence between Queensland domestic prices and relatively lower prices in the southern states. Goldman Sachs predicted the current scenario of Queensland gas exports to the southern states will reverse by 2014–15.

The 2012 Queensland review noted transportation costs would likely constrain flows of Victorian gas into Queensland, unless the gas price differential becomes sufficiently wide. Overall, it expected the gas market to further tighten from 2014–15 through to 2021, when greater volumes of unconventional gas—such as shale gas from the Cooper Basin and CSG from New South Wales—may become available.[28] ACIL Tasman also considered the development of shale gas may cap the upside in gas prices from around 2021.[29]

AEMO modelled in 2012 that eastern Australia has sufficient gas reserves to meet demand over the period to 2032, but that the speed of developing new reserves is crucial. It noted the relatively small volume of uncommitted 2P gas reserves, combined with a large proportion of reserves being earmarked for LNG export, create challenges for domestic supply.

10 EnergyQuest, *Energy Quarterly*, August 2011, pp. 94–5.
11 EnergyQuest, *Energy Quarterly*, August 2011, p. 9.
12 AEMO, *Gas statement of opportunities for eastern and southern Australia*, Executive briefing, 2011.
13 BREE, *Gas market report*, July 2012; ACIL Tasman, *National gas outlook: domestic gas prices and markets,* Presentation by Paul Balfe, 30 May 2012.
14 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, pp. 25–26.
15 AEMO, *2012 Electricity statement of opportunities,* p. iii; AEMO (unpublished briefing to AER, November 2012).
16 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, p. 23, 27, 38.
17 Australian Government, *Energy White Paper* 2012, p. 141.
18 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, pp. ix, x.
19 BREE, *Gas market report*, July 2012, p. 45.
20 EnergyQuest, *Energy Quarterly*, August 2012, p. 9.
21 EnergyQuest, *Energy Quarterly*, August 2012, p. 22.
22 BREE, *Gas market report*, July 2012, p. 56.
23 Goldman Sachs, *NSW gas briefing*, 2 October 2012, p. 2.
24 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, p. 23; BREE, *Gas market report*, July 2012, pp. 50, 66.
25 BREE, *Gas market report*, July 2012, p. iv.
26 BREE, *Australian energy technology assessment 2012*, p. 18.
27 Goldman Sachs, *NSW gas briefing*, 2 October 2012.
28 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, pp. vii, 27,37.
29 ACIL Tasman, *National gas outlook: domestic gas prices and markets*, Presentation by Paul Balfe, 30 May 2012.

AEMO found that a 15 per cent reduction in reserve development could cause supply shortfalls to the LNG export and domestic markets from 2016.[30] While a shortfall for LNG contract obligations could be alleviated by diverting Cooper Basin gas from the domestic market, this diversion would likely have a flow-on impact in the New South Wales domestic market. This scenario would present opportunities to further develop CSG reserves in New South Wales (in the Gunnedah, Gloucester and Sydney basins) and expand gas pipeline capacity to transport gas to demand centres.

The *Energy White Paper 2012* identifies a number of potential reforms the Australian Government is examining with state and territory governments to help alleviate transitional pressures in the eastern gas market. The reforms include:

- developing a national gas supply hub trading model to enhance market transparency and reliability of supply. In December 2012, SCER will consider options for implementing a trading hub market at Wallumbilla in Queensland (section 3.4.4)
- streamlined third party access to underutilised (but contracted) capacity on gas pipelines to enhance trading opportunities

Alongside these reforms, the Australian Government is working through SCER to develop a nationally harmonised regulatory framework for the CSG industry; enhance understanding of the impacts of CSG development on groundwater and the environment; and develop a world-class multiple use framework to promote coexistence.[31]

3.5.2 Spot market prices

The Victorian wholesale gas market (from 1999), and the short term trading market for Sydney and Adelaide (from September 2010) and Brisbane (from December 2011) provide data on spot gas prices. Section 3.4 provides background on these markets.

Table 3.3 sets out average annual spot prices, while figure 3.5 illustrates weekly averages. Figure 3.6 illustrates recent winter prices. The data are ex ante prices derived from demand forecasts; these prices form the main basis for settlement in the Victorian and short term trading markets. But design differences between the two markets limit the validity of price comparisons. In particular, the Victorian market is for gas only, while prices in the short term trading market cover gas *and* transmission pipeline delivery to the hub. For comparative purposes, the data include estimates for Melbourne gas prices, based on the Victorian wholesale price *plus* an estimate of transmission pipeline delivery costs to the metropolitan hub.[32]

Average daily spot prices for gas in Melbourne, Sydney and Adelaide were significantly higher in 2011–12 than in the previous year (table 3.3). Average prices rose by 45 per cent in Sydney, 33 per cent in Melbourne and 20 per cent in Adelaide. Average spot prices in 2011–12 ranged from $3.45 (Sydney) to $3.79 (Adelaide).

Table 3.3 Average daily spot gas prices ($ per gigajoule)

	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
2011–12	3.51	3.45	3.65	3.79
2010–11		2.37	2.74	3.17

Notes:

Volume weighted ex ante prices. Sydney, Adelaide and Brisbane data are short term trading market prices in each hub. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's current transmission withdrawal tariff ($0.3685 per gigajoule) for the two Melbourne metropolitan zones.

Sources: AER estimates (Melbourne); AEMO (other cities).

Weekly prices (figure 3.5) show significant alignment across the four capital cities. While prices in all hubs tend to be higher in winter than in summer, prices above $4 per gigajoule were uncommon until winter 2012. A step change in prices occurred at this time, with monthly averages in all cities rising to $5–8 per gigajoule. Compared with July 2011, average prices in July 2012 were around 85 per cent higher in Sydney, 69 per cent higher in Adelaide and 62 per cent higher in Victoria (figure 3.6).

Winter prices peaked at $17.30 per gigajoule in Sydney (on 23 June 2012), $14.89 per gigajoule in Adelaide (on 4 July), $15.57 per gigajoule in Victoria (on 7 July) and over $8 per gigajoule in Brisbane (on several days in July). Prices began to ease during August and returned to levels below $5 per gigajoule in September 2012, but remained well above longer term averages (figure 3.5).

A range of factors might have contributed to the price spikes in winter 2012. This period coincided with a significant tightening in the contract market for gas in eastern Australia (section 3.5.1). Also, gas powered generation increased in winter 2012, although overall gas demand was relatively stable. AEMO reported gas spot prices were largely unaffected by the introduction of carbon pricing on 1 July.[33]

30 AEMO 2012 (unpublished briefing to AER, November 2012).

31 Australian Government, *Energy White Paper* 2012, p. xxi.

32 The Sydney data in table 3.3 and figures 3.5–3.6 exclude the 1 November 2010 price of $150 per gigajoule, which data errors caused.

33 AEMO, *Carbon price—Market review*, 8 November 2012.

Figure 3.5
Spot gas prices—weekly averages

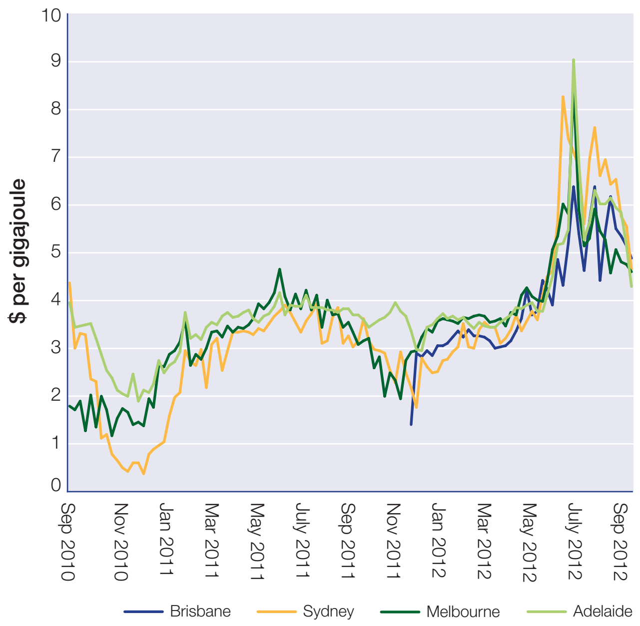
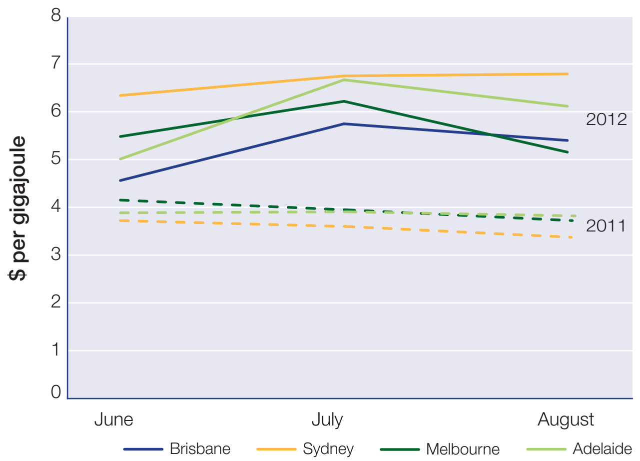


Figure 3.6
Spot gas prices—winter 2011 and 2012



Notes (figures 3.5 and 3.6):

Volume weighted ex ante prices. Sydney, Adelaide and Brisbane data are short term trading market prices in each hub. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's current transmission withdrawal tariff ($0.3685 per gigajoule) for the two Melbourne metropolitan zones.

Sources: AER estimates (Melbourne); AEMO (other cities).

While factors such as changes in contract positions might have flowed through to spot prices, the AER detected several instances of participants rebidding their offers on high price days and driving prices higher than would otherwise be the case. This behaviour was evident in both the short term trading market and the Victorian gas market. In particular, the tighter market appears to have enhanced opportunities for some market participants to influence price outcomes through strategic bidding. This influence is indicated by significant variations between forecast prices, ex ante prices and ex post prices (which account for the impact of deviations from the day-ahead market schedule on the gas day). Linked to this variation were poor quality demand forecasts by participants on a number of days. The demand forecasting issues and price variations most commonly occurred in Sydney, and were typically accompanied by significant rebidding.

The AER inquired into participant demand forecasts, offers and bids over the winter period, and will report on compliance issues in quarterly compliance reports (published on the AER website).

3.6 Compliance monitoring and enforcement

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to the short term trading market, the Victorian gas market and the bulletin board. Its compliance activity relates to relevant participants, including upstream gas producers, gas pipeline entities and gas retailers.[37]

The AER takes a transparent approach to monitoring, compliance and enforcement, publishing quarterly reports on activity. It also draws on spot market and bulletin board data to publish weekly reports on gas market activity in eastern Australia.

Timely and accurate data and efficient pricing maintain confidence in gas markets and encourage efficient investment in energy infrastructure. The AER monitors the

34 EnergyQuest, *Energy Quarterly*, August 2012, pp. 2, 22, 94–5.

35 ACIL Tasman, *National gas outlook: domestic gas prices and markets*, Presentation by Paul Balfe, 30 May 2012.

36 Economics and Industry Standing Committee (Parliament of Western Australia), *Inquiry into Domestic Gas Prices*, Report no. 6 in the 38th Parliament, 24 March 2011.

37 Chapter 4 of this report covers gas transmission while chapter 5 covers gas retailing. For convenience, section 3.6 includes compliance issues for pipeline and retail entities in relation to the short term trading market, the Victorian gas market and the bulletin board.

Box 3.1 Western Australia's domestic gas market

Because Western Australia is a major LNG exporter, the domestic market is exposed to price volatility in international energy markets. Domestic gas prices in Western Australia remained relatively low until 2006, when rising production costs and strong gas demand—driven partly by the mining boom—put upward pressure on prices. Rising international LNG and oil prices added to this pressure.

EnergyQuest reported in 2012 that domestic demand in Western Australia was subdued, with only 0.9 per cent annual growth in the past five years. It noted average prices rose to around $4.20 per gigajoule in June 2012, but may have been higher in the absence of low priced historical contracts. Gas prices under new contracts (such as the Reindeer project in the Carnarvon Basin) were being struck at prices as high as $10 per gigajoule.[34]

ACIL Tasman considered recent movements in Western Australian gas prices reflect emerging shortages in gas supply relative to demand, rising costs for incremental supply, and competition from LNG. It considered prices for new contracts are likely to remain around $8–10 per gigajoule.[35]

In 2011 a West Australian parliamentary inquiry recommended initiatives to improve the efficiency of the wholesale market by enhancing transparency, competition and liquidity. Several proposed initiatives mirrored recent reforms in eastern Australia, including the introduction of a short term trading market, a gas market bulletin board and a gas statement of opportunities. The inquiry also recommended eliminating joint marketing arrangements when authorisations granted by the Australian Competition and Consumer Commission come up for review in 2015.[36]

The West Australian Government passed legislation in March 2012 to establish a gas bulletin board and publish an annual gas statement of opportunities. It expected the bulletin board to commence operating in July 2013 and to publish the first gas statement of opportunities in mid-2013. It did not plan to establish a short term trading market with market settlement and trading services.

spot markets and bulletin board to improve data provision and has committed to the SCER to monitor gas markets to detect any evidence of the exercise of market power.

The AER's compliance monitoring and enforcement activity in gas over the past 12–18 months focused on:

- identifying possible compliance issues related to record spot price outcomes for gas in winter 2012 (see section 3.5.2)
- high MOS payments in the short term trading market (section 3.6.1)
- the quality of data provision to the short term trading market and bulletin board (section 3.6.2).

3.6.1 Market Operator Service payments

MOS services are required when scheduled pipeline deliveries do not match actual gas demand in the short term trading market. While some balancing is required every day due to variations in forecast and actual demand, some payments for these services have been unusually high. Figure 3.7 shows daily MOS payments for each hub and highlights some extreme outcomes.

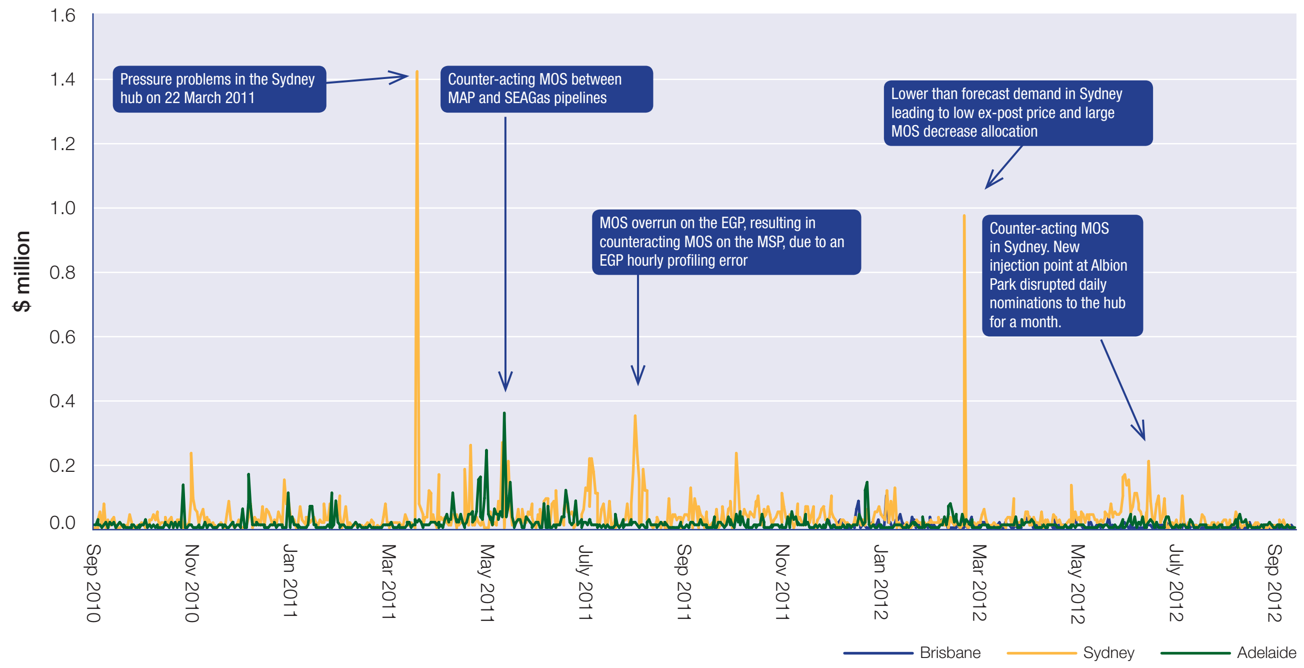
The highest MOS payment in 2011–12 occurred in Sydney on 27 February (around $1 million), following a manual input error on the Eastern Gas Pipeline. The AER held discussions with operating staff and received written undertakings from the pipeline's operator on this matter. It is continuing to closely monitor MOS payments at all hubs.

3.6.2 Data provision by pipeline entities

Errors in data provision by pipeline entities to the short term trading market and bulletin board have been ongoing. The AER served an infringement notice on one pipeline entity in June 2012 for an alleged breach of the Gas Rules. It is also auditing facility operators' processes for achieving compliance in this area, beginning with APA Group, AGL Energy and Epic Energy in 2012–13. It will report the audit outcomes in its quarterly compliance reports.

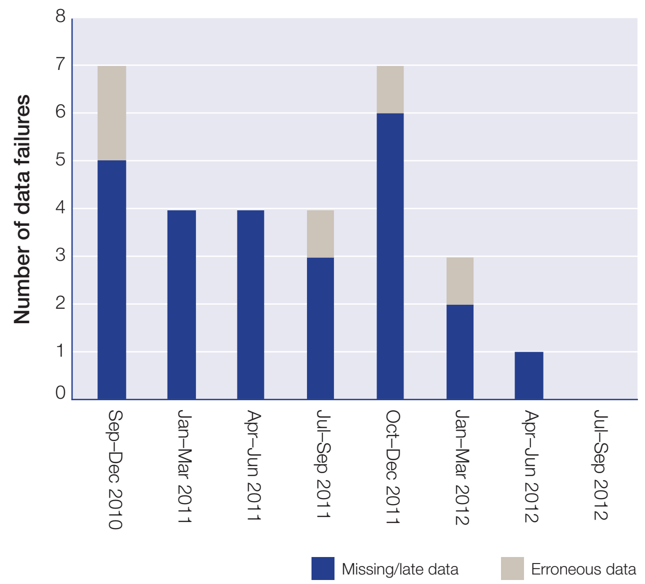
Since the AER increased its focus on this area, the quality of data provision to the short term trading market has improved (figure 3.8). In the six months to 30 September 2012, the AER identified only one error in the submission of pipeline data.

Figure 3.7
MOS payments in Sydney, Adelaide and Brisbane



Source: AER.

Figure 3.8
Data failures in the short term trading market—quarterly



Note: September–December 2010 covers four months.

Source: AER.

3.7 Upstream competition

Investment over the past decade developed an interconnected transmission pipeline system linking gas basins in southern and eastern Australia (chapter 4). While gas tends to be purchased from the closest possible source to minimise transport costs, interconnection of the major pipelines provides energy customers with greater choice and enhances the competitive environment for gas supply.

Gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are now served by multiple transmission pipelines from multiple gas basins. In particular, the construction of new pipelines and the expansion of existing ones opened the Surat–Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition. By contrast, Brisbane is served by only one transmission pipeline (Roma to Brisbane).

The bulletin board (section 3.4.3) provides real-time information on the gas market to enhance competition. The AER draws on the bulletin board to report weekly on gas market activity in eastern Australia. Its reporting covers gas flows on particular pipelines and gas flows from competing basins to end markets.

Figure 3.9 illustrates recent trends in gas delivery from competing basins into New South Wales, Victoria and South Australia since the bulletin board opened in July 2008:

- While New South Wales historically relied on Cooper Basin gas shipped on the Moomba to Sydney Pipeline, gas shipped on the Eastern Gas Pipeline from Victoria's Gippsland Basin now supplies an equivalent proportion of the state's gas requirements. Gas flows on the Moomba to Sydney Pipeline show significant seasonal fluctuations, while flows on the Eastern Gas Pipeline are relatively steady. There are relatively smaller flows (both northwards and southwards) across the New South Wales–Victoria Interconnect.
- While the Gippsland Basin remains the principal source of gas supply for Victoria, the state also sources some of its requirements from the Otway Basin via the South West Pipeline (an artery of the Victorian Transmission System). Figure 3.9 also illustrates the seasonal nature of Victorian gas demand, with significant winter peaks.
- While the Moomba to Adelaide Pipeline historically transported most of South Australia's gas from the Cooper Basin and more recently from the Surat–Bowen Basin, the SEA Gas Pipeline now transports greater volumes of gas to South Australia from Victoria's Otway Basin.

The extent to which new investment delivers competition benefits to customers depends on a range of factors, including pipeline access and the availability of gas from alternative sources. In particular, capacity constraints limit access on some pipelines. Access seekers must decide whether to try to negotiate a capacity expansion. For a covered pipeline, the regulator (or, in Western Australia, a separate arbitrator) may be asked to arbitrate a dispute over capacity expansions.

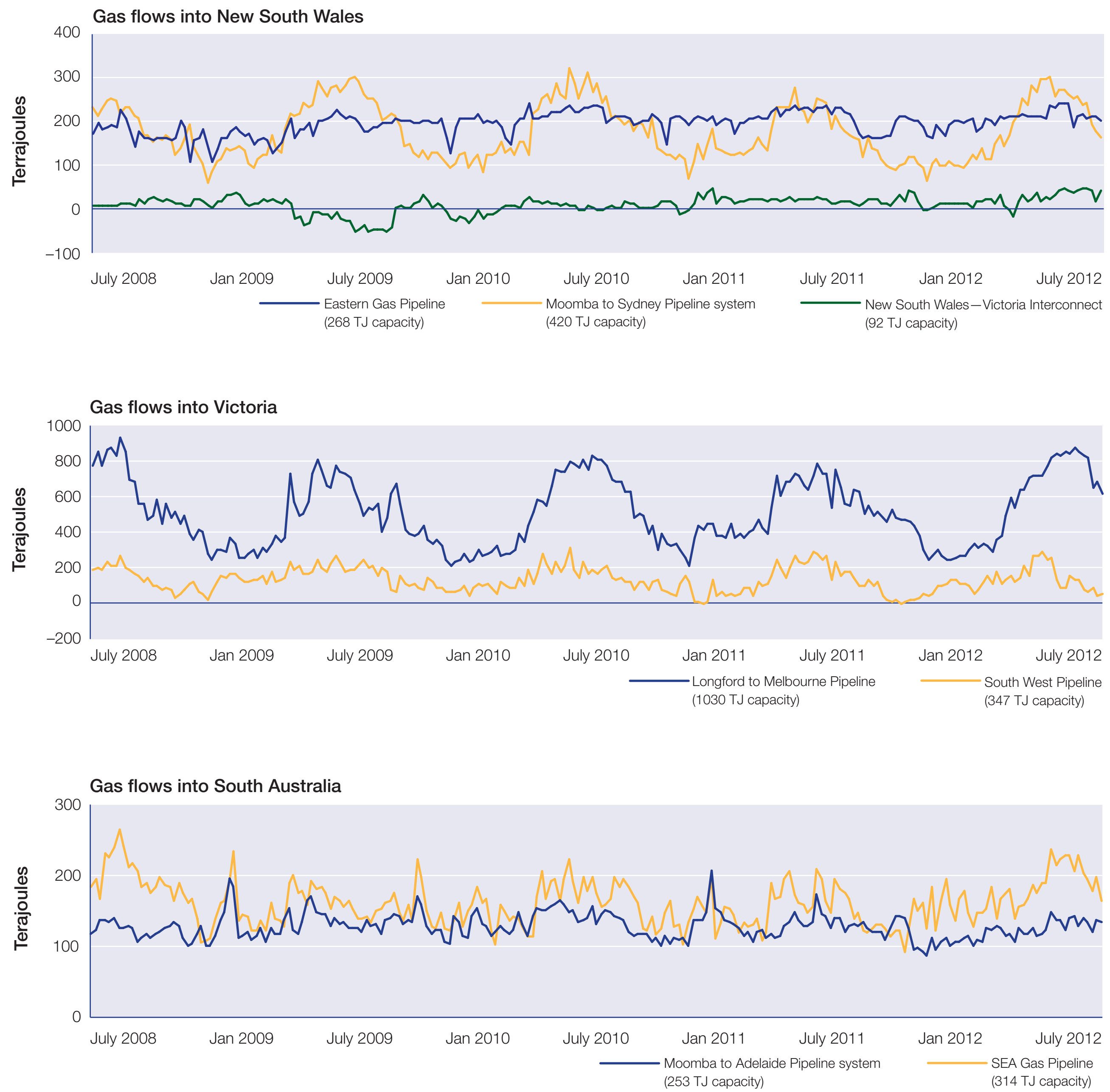
3.8 Gas storage

Gas can be stored in its natural state in depleted underground reservoirs and pipelines, or post liquefaction as LNG in purpose built facilities. Given Australia's increasing reliance on gas powered electricity generation, gas storage enhances the security of energy supply by allowing for system injections at short notice to better manage peak demand and emergencies. It also allows producers to meet contract requirements if production is unexpectedly curtailed, and provides retailers with a hedging mechanism if gas demand is significantly above forecast.

Conventional gas storage facilities are located in Victoria, Queensland, Western Australia and the Cooper Basin. In Victoria, the largest facility is the Iona gas plant, owned by EnergyAustralia, which has 22 PJ of storage capacity and can deliver 570 terajoules of gas per day. In Queensland, AGL Energy in August 2011 began injecting and storing gas underground at the depleted Silver Springs reservoir in central Queensland. The facility will support the development of the Curtis LNG project; it will also allow AGL to manage its gas supply during seasonal variations in summer and winter. In Western Australia, an expansion of the Mondarra storage facility will increase its storage capacity to 15 PJ, and will allow injections and withdrawals on both the Dampier to Bunbury and Parmelia pipelines.

The Dandenong LNG storage facility in Victoria (0.7 PJ) is Australia's only LNG storage facility. It provides the Victorian Transmission System with additional capacity to meet peak demand and provide security of supply. In New South Wales, AGL Energy is constructing a $300 million LNG storage facility to secure supply during peak periods and supply disruptions. Due to be completed by 2014, the facility will have a peak supply rate of 120 terajoules per day.

Figure 3.9
Gas flows in eastern Australia



Note: Negative flows on the New South Wales – Victoria Interconnect represent flows out of New South Wales into Victoria.
Sources: AER; Natural Gas Market Bulletin Board (www.gasbb.com.au).