3 UPSTREAM GAS MARKETS

Gas production in eastern Australia is forecast to treble over the next three to five years to satisfy a rapid expansion in liquefied natural gas (LNG) export demand. The development of three projects in Queensland to supply LNG exports is placing significant pressures on the domestic market. Conditions will further tighten when the projects ramp up to full capacity from 2015–18.

Australia's domestic gas 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, and to remove impurities. The two main types of gas produced in Australia are conventional gas and coal seam gas (CSG). Conventional gas is found trapped in underground reservoirs, often along with oil. In contrast, CSG is a form of gas extracted from coal beds. Rising gas prices and improved extraction techniques have raised commercial interest in developing other types of unconventional gas such as shale and tight gas;[1] Santos began producing shale gas in the Cooper Basin in 2012.

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 also refers to domestic markets in Western Australia and the Northern Territory, and to LNG export markets. Other segments of the gas supply chain are considered in chapters 4 (transmission and distribution pipelines) and 5 (retail markets).

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. Tight gas is found in low porosity sandstone and carbonate reservoirs.

2 The AER has compliance and enforcement responsibilities under the National Gas Rules in relation to the Natural Gas Market Bulletin Board, the Victorian wholesale gas market and the short term trading market in Sydney, Adelaide and Brisbane.

3.1 Gas reserves and production

In August 2013 Australia's proved and probable (2P) gas reserves stood at around 141 000 petajoules (PJ), comprising 97 000 PJ of conventional natural gas and 44 000 PJ of CSG (table 3.1 and figure 3.2).

Australia produced 2206 PJ of gas in 2012–13, of which half was for the domestic market. Production for domestic use was up 3.3 per cent from levels in 2011–12. The CSG share of production for domestic use was steady at 23 per cent. Around half 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 new LNG projects in Queensland and Western Australia (section 3.2.1).

3.1.1 Geographic distribution

Eastern Australia contains around 36 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 81 per cent of reserves in eastern Australia and supplies 34 per cent of that market. In New South Wales, limited commercial production of CSG occurs in the Sydney and Gunnedah basins. Overall, CSG production in eastern Australia rose by 3 per cent in 2012–13.

The Gippsland Basin off coastal Victoria supplies 37 per cent of the eastern market. Production in Victoria's offshore Otway Basin (15 per cent of eastern production) has risen significantly since 2004.

After several years of decline, Cooper Basin reserves in central Australia rose in the past three years, and were up 14 per cent in the year to June 2013. Production in the basin may continue to rise, with new activity focused on the development of shale gas. Santos commenced production from its shale gas well in the Cooper Basin in 2012.

Western Australia's offshore Carnarvon Basin holds about half of Australia's 2P gas reserves. It supplies about 31 per cent of Australia's domestic market and 99 per cent of Australia's LNG exports.[3] The Bonaparte Basin along the north west coast also produces LNG for export. The Bonaparte Pipeline ships gas from the basin 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.

3 Data on gas production, consumption and reserves are sourced from EnergyQuest, *Energy Quarterly*, August 2013.

Figure 3.1
Domestic gas supply chain

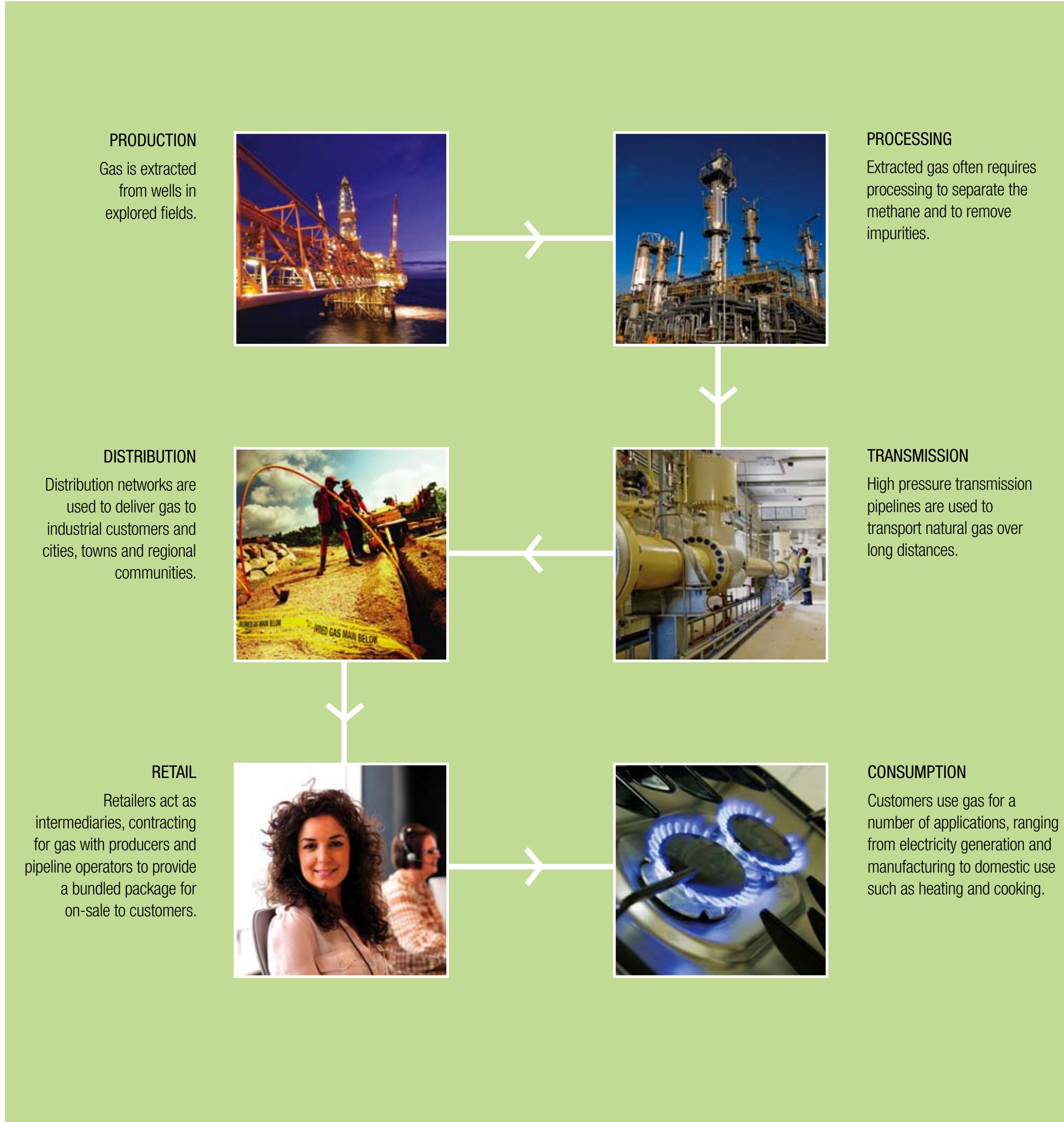


Image sources: Origin Energy, Woodside, Jemena.

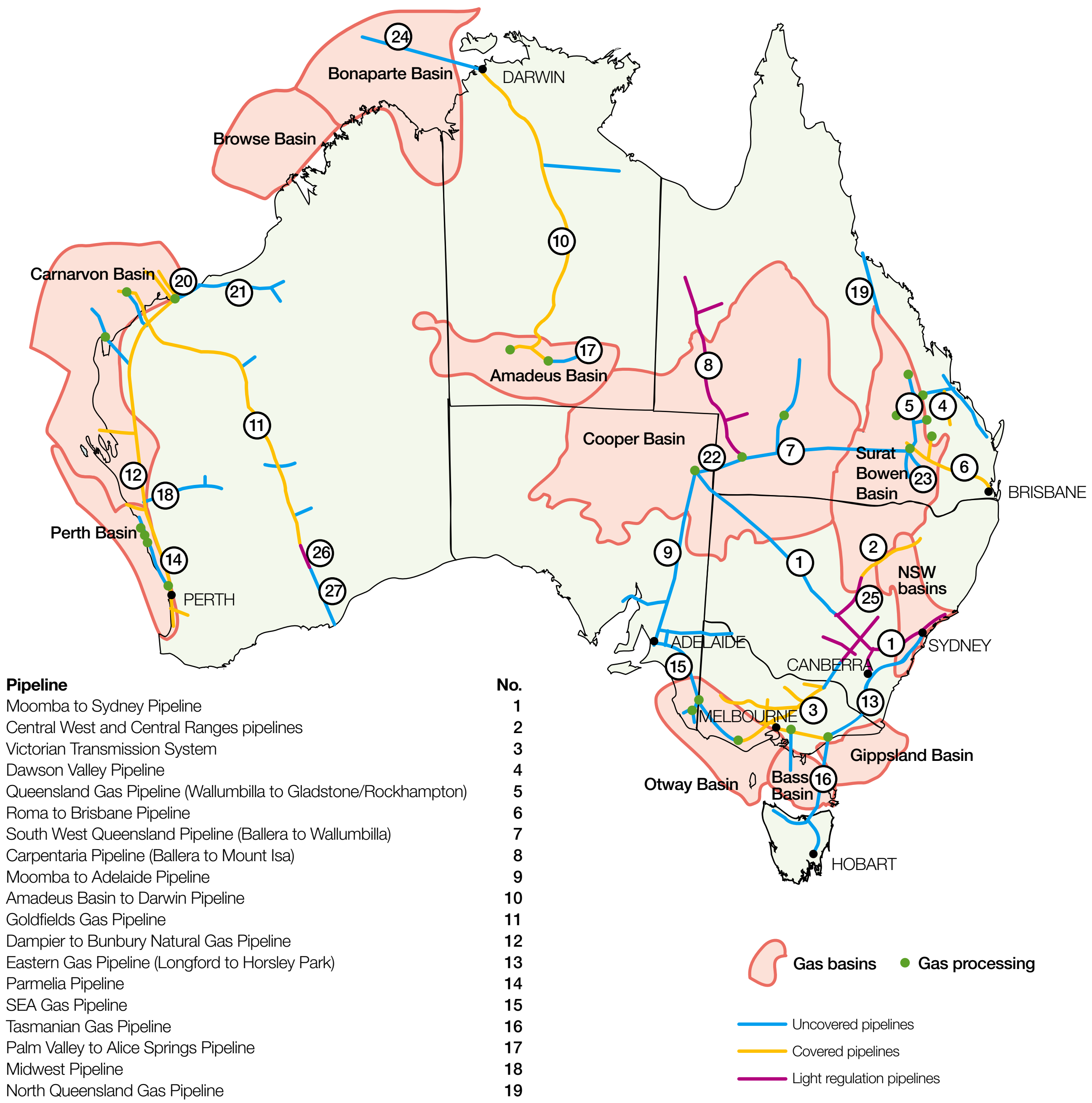
Table 3.1 **Gas reserves and production, 2013**

GAS BASIN	PRODUCTION (YEAR TO JUNE 2013)		PROVED AND PROBABLE RESERVES[1] (AUGUST 2013)	
	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS				
EASTERN AUSTRALIA				
Cooper (South Australia–Queensland)	86	7.8	1 992	1.4
Gippsland (Victoria)	274	24.8	3 684	2.6
Otway (Victoria)	109	9.9	821	0.6
Bass (Victoria)	11	1.0	250	0.2
Surat–Bowen (Queensland)	1	0.1	135	0.1
New South Wales basins	0	0.0	16	0.0
WESTERN AUSTRALIA				
Browse	0	0.0	17 384	12.3
Carnarvon	337	30.6	71 855	50.8
Perth	7	0.6	41	0.0
NORTHERN TERRITORY				
Amadeus	0	0.0	138	0.1
Bonaparte	24	2.2	1 054	0.7
Total conventional natural gas	849	77.0	97 370	68.9
COAL SEAM GAS				
Surat–Bowen (Queensland)	248	22.5	41 146	29.1
New South Wales basins	5	0.5	2 805	2.0
Total coal seam gas	254	23.0	43 951	31.1
AUSTRALIAN TOTALS	1 102	100.0	141 321	100.0
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	1 089			
Bonaparte (Northern Territory)	15			
Total liquefied natural gas	1 103			
TOTAL PRODUCTION	2 206			

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 2013.

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.

3.2 Gas demand

Australia consumed 1102 PJ of gas in 2012–13 (up slightly from 1067 PJ in 2011–12) for industrial, commercial and domestic use. The consumption profile varies across the jurisdictions.

While gas is widely used for industrial manufacturing, around 31 per cent of Australian gas consumption in 2011–12 was for electricity generation.[4] 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. Exports of Australian produced LNG rose in 2012–13 by 29 per cent (to 20.1 million tonnes)[5] and major players are continuing to expand capacity:

- Chevron's Gorgon project (Carnarvon Basin) is scheduled to begin operation in 2015 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 67 per cent complete in June 2013. In addition, Chevron committed in September 2011 to the $29 billion Wheatstone project (foundation capacity of 8.9 million tonnes per year). 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 2016.
- Woodside announced in 2013 that development of the Browse LNG project would involve an offshore project using floating LNG technology. It expects to commence front end engineering and design work in 2014.

In Queensland, long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, spurred the development of several LNG projects near the port of Gladstone. Construction of three projects, including 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 $24.7 billion Australia Pacific LNG project (Origin Energy, ConocoPhillips and Sinopec) is expected to begin LNG exports in mid 2015, with exports from a second train expected to commence late 2015.

A decision on the development of a fourth project—the Arrow LNG project (Shell and PetroChina)—was delayed to the end of 2013 amid speculation that it may link to one of the other projects.

4 Bureau of Resources and Energy Economics (BREE), *Gas market report*, October 2013, p. 26.

5 LNG production and export data are sourced from EnergyQuest, *Energy Quarterly*, August 2013.

3.3 Industry structure

Six major producers met 66 per cent of domestic gas demand in 2012–13: Santos, BHP Billiton, ExxonMobil, Origin Energy, Woodside and Apache Energy.[6] The mix of players varies across the basins.

3.3.1 Market concentration

Various factors affect market concentration in a gas basin, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Figure 3.3 illustrates 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 2013.

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 96 per cent of production in the Gippsland Basin. Nexus, which began production from the Longtom gas project in October 2009, has a 4 per cent market share.

The Otway Basin has a more diverse ownership base, with Origin Energy (31 per cent), BHP Billiton (21 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 (17 per cent), ConocoPhillips (17 per cent), Sinopec (11 per cent), Santos (9 per cent), 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.

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 the Surat–Bowen Basin. But new entry and a series of mergers and acquisitions in 2009–11 led to a more diverse market structure (figure 3.4). By 2013 the three largest players jointly owned 44 per cent of reserves (BG Group 20 per cent, and Origin Energy and ConocoPhillips each about 12 per cent).

In central Australia, a joint venture led by Santos (65 per cent) dominates production in the Cooper Basin. The other participants are Beach Petroleum (21 per cent) and Origin Energy (13 per cent).

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 (36 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.

Woodside (25 per cent) and Apache Energy (24 per cent) are the largest producers for Western Australia's domestic market. Santos (19 per cent), BP and Chevron (9 per cent each), and BHP Billiton and Shell (5.5 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.

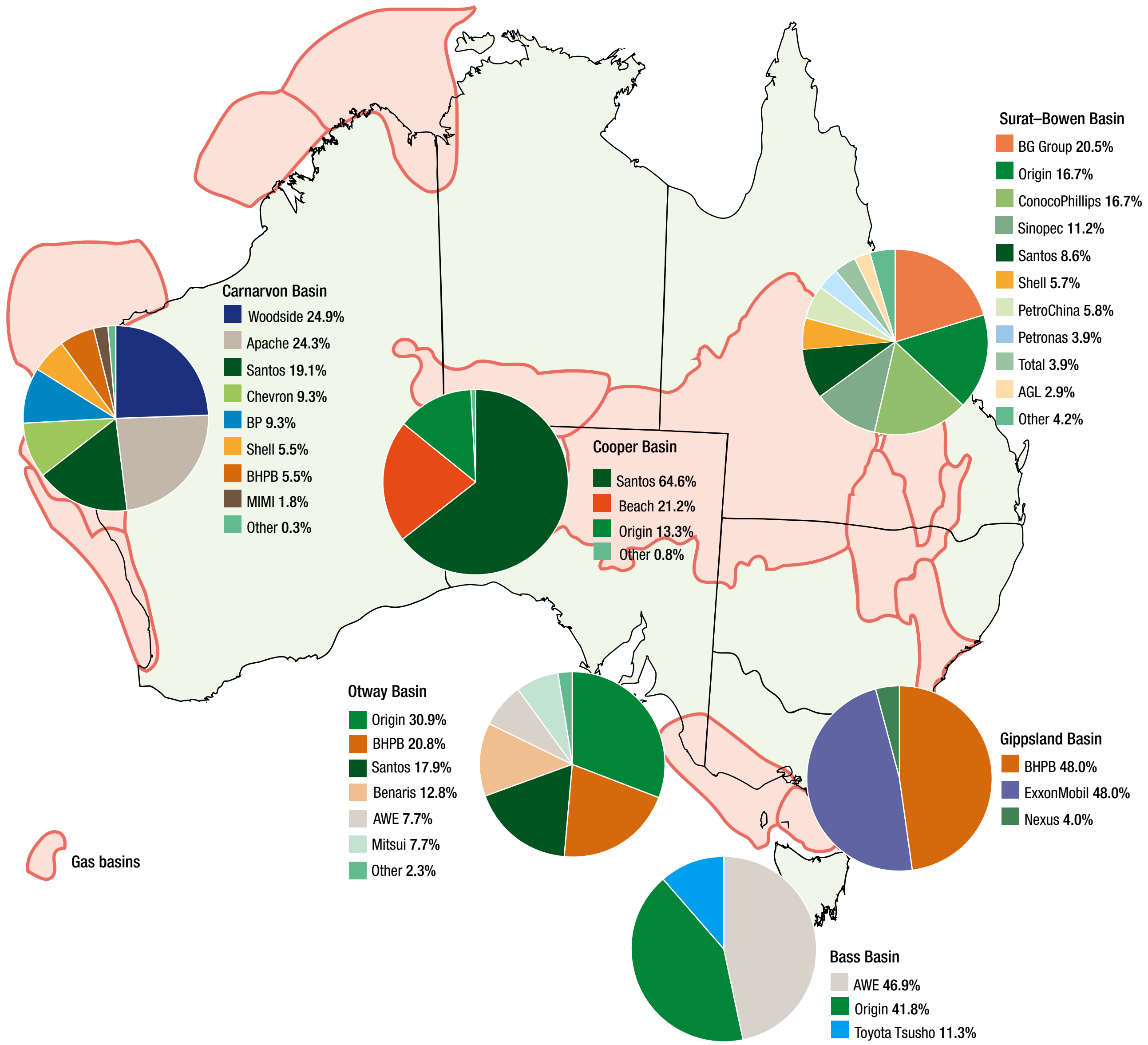
3.3.2 Vertical integration

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 that owns gas powered generation plant in all mainland National Electricity Market (NEM) regions. 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 12.5 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 owns significant gas powered generation in South Australia and began acquiring CSG interests in Queensland and New South Wales in 2005.
- EnergyAustralia (formerly TRUenergy) is a third major retailer and generator in eastern Australia. It has gas storage facilities in Victoria and acquired gas reserves in the Gunnedah Basin (New South Wales) in 2011.

6 EnergyQuest, *Energy Quarterly*, August 2013.

Figure 3.3
Market shares in domestic gas production, by basin, 2012–13



Note: Excludes LNG.
Data source: EnergyQuest 2013 (unpublished data).

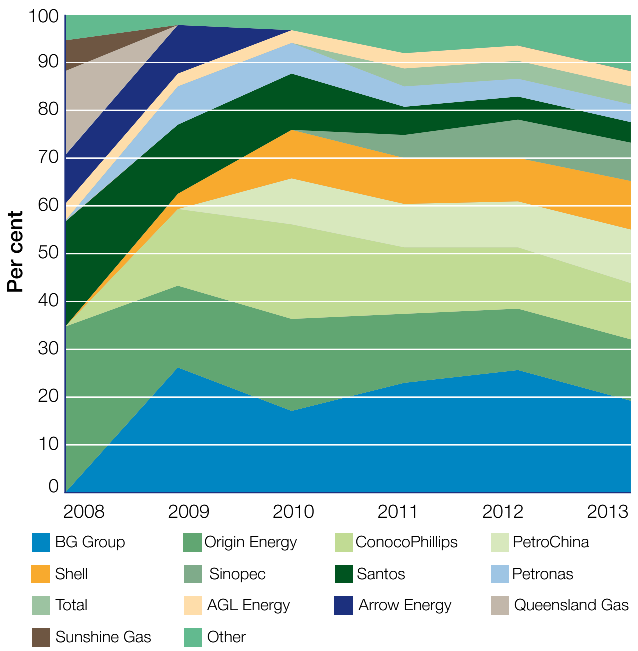
Table 3.2 Market shares in proved and probable gas reserves, by basin, 2013 (per cent)

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)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Chevron	36.3														18.5
Shell	17.3	14.8				10.0									13.6
ExxonMobil	14.3											45.4			8.5
Inpex		53.4		1.7											6.6
BG						19.5									5.7
Woodside	11.1														5.7
Origin			50.8			12.5	12.4						35.0	42.5	4.1
Santos	1.2			1.7	68.2	4.7	63.4		80.0			5.8	18.2		4.0
Total		23.4				3.6									3.9
ConocoPhillips				8.5		12.1									3.6
BHPB	3.8											45.4	12.9		3.2
PetroChina						10.9									3.2
Sinopec						8.1									2.4
CNOOC	1.0					5.6									2.2
BP	4.1														2.1
Apache	3.7														1.9
MIMI	3.1														1.6
AGL						3.2				100.0	100.0				1.3
Petronas						3.6									1.1
Kogas		2.2				1.9									0.8
Eni				86.7											0.6
Kufpec	1.1														0.6
Osaka Gas	0.7	0.9													0.5
Mitsui						1.2							8.4		0.4
Metgasco								96.2							0.2
Beach							18.0								0.2
EnergyAustralia									20.0						0.2
Kansai Electric	0.4														0.2
Toyota Tsusho						0.5							2.6	11.3	0.2
Drillsearch							6.2								0.1
Nexus												3.3			0.1
Benaris													14.5		0.1
AWE			20.9										8.4	46.3	0.1
Magellan					31.8										0.0
Empire oil and gas			21.6												0.0
ERM Power			6.7												0.0
Other	1.9	5.3		1.4		2.6		3.8				0.1			2.4
TOTAL (PETAJOULES)	71 855	17 384	53	1054	180	41 372	1913	355	1426	454	50	3720	820	250	140 887

Notes:
Based on 2P reserves at August 2013.
Not all minority owners are listed.
Source: EnergyQuest 2013 (unpublished data).

Figure 3.4

Market shares in proved and probable reserves, Surat–Bowen Basin, 2008–13



Data source: EnergyQuest 2008–13 (unpublished data).

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 sell it to business and residential customers. Australian gas prices have generally been low by international standards, typically $3–4 per gigajoule. 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.

While gas prices were historically struck under confidential, long term contracts, there has been a recent shift towards shorter term contracts, the inclusion of review provisions and the emergence of spot markets:

- A short term trading market for gas was launched in Sydney and Adelaide in 2010, with Brisbane following in 2011 (section 3.4.1). The market provides a means for participants to manage contractual imbalances, and is supported by a National Gas Market Bulletin Board (section 3.4.3).
- Victoria established a wholesale spot market in 1999 for gas sales, to manage system imbalances and pipeline network constraints (section 3.4.2).
- In consultation with industry, the Australian Energy Market Operator (AEMO) is developing a gas trading exchange to be located at Queensland's Wallumbilla hub. The exchange is scheduled for launch by March 2014 (section 3.4.4).

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to these spot markets and the bulletin board. Timely and accurate data and efficient pricing maintain confidence in gas markets and encourage efficient investment in energy infrastructure. The AER monitors the markets and bulletin board to improve data provision and to detect any evidence of the exercise of market power. It also draws on this information to publish weekly reports on gas market activity 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. AEMO operates the market, which was designed to enhance gas market transparency and competition by setting prices based on supply and demand conditions.[7]

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 between their gas injections (deliveries) into and withdrawals from the market. Market participants include energy retailers, power generators and other large gas users. Shippers deliver gas to be sold in the market, and users buy gas for delivery to customers; many participants act both as shippers and users, but only their net position is traded.

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 market rules require the participants bid in 'good faith'.

Based on the market schedule, shippers nominate the quantity of gas that 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, as a result of demand variations and other factors. As gas requirements become better known during the day, shippers may renominate quantities with pipeline operators (depending on the terms of their contracts).

Pipeline operators use balancing gas to prevent imbalances in gas supply to distribution networks if demand forecasts are inaccurate. AEMO procures this balancing gas—market operator services (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. The AER has recently taken action to reduce a tendency for excessive MOS payments (box 3.1).

Section 3.5.1 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.

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

Box 3.1 Reducing excessive MOS payments

There has been limited new entry in the short term trading market since it commenced in September 2010. The high costs of covering MOS services may be a deterrent. The AER has identified a tendency for excessive MOS payments on high demand days, including during winter in the Sydney and Adelaide market. In some instances, the volume of MOS gas significantly exceeds the magnitude of the underlying physical imbalance in gas volumes.

In the interests of lowering costs for participants, the AER targeted excessive MOS volumes in the Sydney and Adelaide hubs. In particular, the AER found physical design and nomination issues in the Adelaide and Sydney hubs periodically raised MOS volumes above the levels required to balance out inaccurate demand forecasts. In some circumstances, this outcome increased costs for participants.

MOS payments for the Sydney hub rose around the time the Albion Park injection point was introduced in May 2012. The injection point is one of three that supply gas from the Eastern Gas Pipeline into the Sydney hub. In meetings with industry, the AER found the high MOS payments resulted from a market participant underforecasting its demand in the Albion Park area of the distribution network. Subsequently, the participant increased its supply through the Albion Park injection point, resulting in a significant reduction in MOS requirements at the Sydney hub.

In Adelaide, the AER found large amounts of MOS were required on days when participants supplied less gas on the Moomba to Adelaide pipeline (MAP) relative to the SEA Gas Pipeline. The issue peaked on 25 June 2013, when MOS payments in Adelaide exceeded $250 000.[8] The issue partly related to design issues in Envestra's Adelaide distribution network that cause parts of the network to be better served by gas from the MAP than from the SEA Gas Pipeline. In particular, flows on SEA Gas are unable to reach all parts of the Adelaide network, resulting in excessive MOS payments on high demand days.

Following a meeting with industry participants, Envestra committed to investigate solutions to the network design issue and report on the matter by December 2013. The AER expects a resolution of this issue would likely reduce MOS payments in the Adelaide hub in 2014.

3.4.2 Victoria's gas wholesale market

Victoria introduced a spot market for gas in 1999 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 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. In common with the short term trading market, only net positions are traded—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]

8 AER, *Gas market significant price variation report: MOS service payments*, 25 June 2013, Adelaide STTM.

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

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 3.5.1 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.

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. It 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.

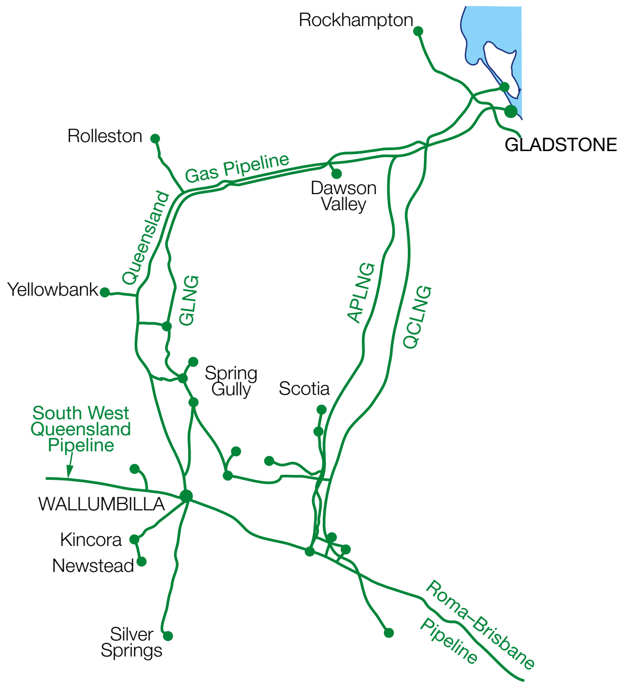
3.4.4 Gas trading exchange at Wallumbilla, Queensland

In consultation with industry, AEMO is progressing the development of a new gas trading exchange at Wallumbilla in Queensland.[10] The exchange is set to be launched by March 2014. Energy ministers commissioned work on the project to support escalating gas development in south east Queensland. In particular, the development of LNG exports

10 For further information, see Standing Council on Energy and Resources and AEMO workstreams.

Figure 3.5

Gas pipelines and production facilities in Wallumbilla area, Queensland



Source: AEMO.

will contribute to Queensland's gas demand rising from 240 PJ per year in 2012 to over 1500 PJ per year by 2016.

Wallumbilla is a major gas supply hub (figure 3.5). As a pipeline interconnection point for the Surat–Bowen Basin, it links gas markets in Queensland, South Australia, New South Wales and Victoria. The diversity of contract positions and the number of participants at Wallumbilla create a natural point of trade.

The new market arrangements aim to promote transparent and efficient gas trading so participants can manage the financial risks associated with variable gas prices. They will also deepen market liquidity by attracting participants such as LNG plants, industrial customers and gas powered generators.

The gas trading exchange will use a brokerage model to match and clear trades between gas buyers and sellers at the Wallumbilla hub's three pipeline delivery points. At market start, AEMO will offer spot and forward products for trade at each delivery point. While the exchange will initially operate only at Wallumbilla, it may later be introduced at other hubs. The flexible design aims to meet industry needs by adapting to the circumstances of any location.

The market design also avoids the need to change infrastructure, operations or contracts. But participants using the gas trading exchange will require access to the transmission pipelines serving the hub, not all of which interconnect. To manage this issue, the gas trading exchange will be supported by a web based platform for participants to advertise their interest in buying or selling gas pipeline capacity in the eastern gas market. AEMO is developing standardised trading terms.

Amendments to the National Gas Law and Rules cover the gas trading exchange. As with other spot markets, the AER will monitor and enforce compliance with the market conduct rules, and report on market activity. It is consulting on its approach with stakeholders. The AER's likely initial focus will be to ensure participants:

- trade only on the basis of gas they intend to physically deliver or receive at the hub
- have sufficient contractual rights to support trades on pipelines at all times.

3.5 Recent developments in east coast gas markets

An interaction of several factors is shifting the dynamics of gas markets in eastern Australia. Rising CSG production, the emergence of spot markets, and improved pipeline interconnection among gas basins have made domestic markets more responsive to customer demand. But the development of LNG export capacity in Queensland is exerting significant pressure on the domestic market.

Gas production in eastern Australia is forecast to treble over the next three to five years to meet international LNG demand,[11] with the first exports scheduled for 2014–15. While Queensland's three LNG proponents each have dedicated gas reserves and pipeline infrastructure, they are also sourcing reserves that might otherwise have been available to the domestic market. This development is making it difficult for domestic customers to source gas under medium to long term contracts.[12]

The effect of these tight conditions was apparent in 2013, with prices in new contracts reportedly linked to international oil prices or LNG netback prices[13] (currently around $10 per gigajoule for export to Japan). Origin Energy and Lumo entered separate gas supply arrangements in 2013 that included explicit links to oil prices.[14] EnergyQuest quoted comments by Santos that some recent gas contract prices are at the upper end of the $6–9 range.[15] A 2013 survey by the Australian Industry Group of over 60 gas using firms estimated recent contract prices for short term delivered gas averaged just over $5 per gigajoule; longer term contract prices averaged $8.72 per gigajoule.[16]

Spot prices for gas also rose in 2012–13, with an above average frequency of price spikes. Average prices rose by 69 per cent in Brisbane,[17] 51 per cent in Sydney, 33 per cent in Melbourne and 34 per cent in Adelaide (section 3.5.1).

Gas market conditions will tighten further when LNG facilities come on line and ramp up to full capacity in 2015–18. While delays affected some projects in 2012, Energy Quest reported favourable weather conditions in 2013 had put back on schedule the development of each project's first train.[18] AEMO forecast that gas supply shortfalls may occur if facilities that are currently dedicated to domestic demand are prioritised to supply LNG export contracts. Without further investment, Queensland could experience a 250 terajoules per day shortfall once all LNG trains reach full output around 2019. If production in Queensland and South Australia is prioritised for export, there would be flow-on effects to New South Wales, with potential shortfalls of 50–100 terajoules per day on winter peak demand days from 2018.[19]

The ramp up to full LNG export capacity will coincide with the expiry of a large number of domestic gas supply contracts. The review and negotiation of contracts in a market exposed to global prices will place further pressure on domestic prices. Overall, contracts covering the supply of around 260 PJ of gas are due to expire by 2018 (figure 3.6). The problem is acute for New South Wales: by 2018, existing contracts will meet less than 15 per cent of that state's gas demand.[20]

11 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013, p. v.

12 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

13 LNG netback prices simulate an export parity price by stripping out shipping, transportation and liquefaction costs.

14 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013, p.33.

15 EnergyQuest, *Energy Quarterly*, August 2013, p. 100.

16 Australian Industry Group, *Energy shock: the gas crunch is here*, July 2013. The quoted prices include transmission pipeline charges.

17 Brisbane prices rose by 69 per cent when comparing average 2012–13 prices with average prices over the seven month period in 2011–12 (1 December 2011 to 30 June 2012) in which the Brisbane market operated. Brisbane prices rose by 82 per cent when comparing average prices for December 2012 to June 2013 with those of the corresponding period in the previous year.

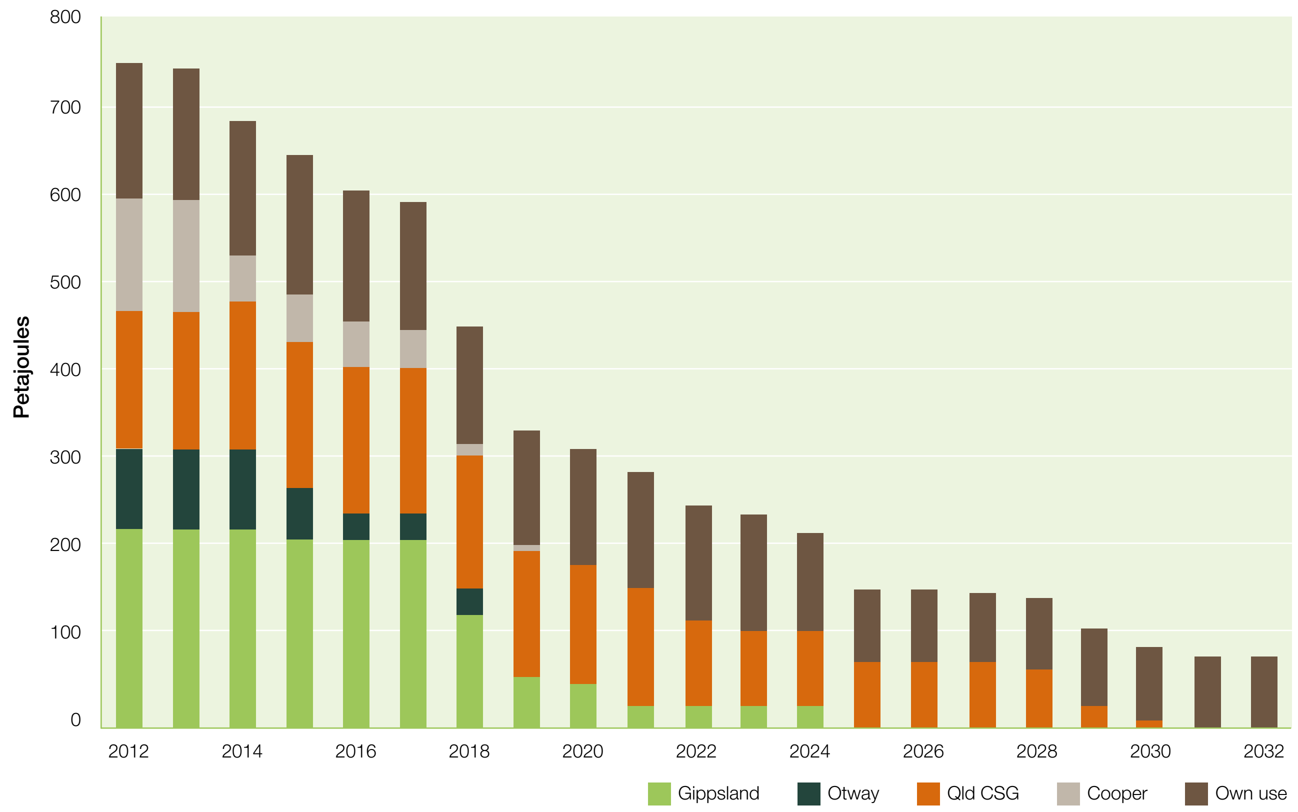
18 EnergyQuest, *Energy Quarterly*, August 2013, p. 64.

19 AEMO, *Gas Statement of Opportunities 2013*, p.iv.

20 BREE, *Gas market report*, October 2013, pp. 17, 41.

Figure 3.6

Contracted gas supply volumes, by basin



Note: Data at May 2012.
Original source: EnergyQuest; graph reproduced in BREE, *Gas market report*, October 2013.

Some domestic producers are increasing supply to meet demand. AEMO reported Victorian gas exports to New South Wales were 46 per cent higher in winter 2013 than a year earlier, and significantly higher than in each of the past four years.[21] APA Group in 2013 committed to an expansion of the Victorian Transmission System (for completion by winter 2015) to support higher export volumes from Victoria to New South Wales. Jemena was also considering an expansion of the Eastern Gas Pipeline to boost capacity into New South Wales, which could be completed by the end of 2015. Elsewhere, Cooper Basin production is also likely to rise, but with the bulk of the increase going into LNG exports.[22]

Interest exists in developing new sources of supply to meet the likely gap in the domestic market. Production from the Kipper Tuna Turrum project in the Gippsland Basin began in 2013. Other proposals relate to the Gunnedah and Gloucester basins in New South Wales, the Ironbark field in the Surat Basin, unconventional sources in the Cooper Basin, and the South Nicholson and Isa Super basins in the Northern Territory and north west Queensland.[23]

The development of coal seam and shale gas resources has raised community concerns about potential impacts on agricultural land use, waterways and native vegetation.[24] These concerns have delayed the development of some projects, notably in New South Wales, which restricted development around communities and water catchments critical to agriculture. EnergyQuest reported in August 2013 that the development of new gas projects in New South Wales had stalled since that state's government announced an exclusion zone policy in February 2013. It also noted widespread anti-CSG protest action, with many farmers and environmentalists seeking tighter restrictions on CSG developments.[25]

Another uncertainty is how rapidly new supplies could be brought online to fill the likely gap in the domestic market. A number of proposed projects remain in the exploration stage and will require the development of new production facilities and transmission pipelines. Additionally, their development may need to be underwritten by long term foundation contracts, leaving it unclear how much capacity would be available for short term contracting.[26]

While LNG export demand is projected to rise exponentially, a countervailing market influence is flatter domestic demand for gas, especially for electricity generation. Gas powered generation accounts for 31 per cent of domestic gas demand in Australia.[27] Subdued electricity demand, the continued rise in renewable generation, the Coalition Government's intention to abolish carbon trading, rising gas prices and the cessation of the Queensland Gas Scheme (which mandated a minimum rate of gas powered generation) have weakened projections on gas powered generation.

AEMO forecast that domestic gas demand would decline until 2016, followed by a gradual recovery (figure 13 in market overview). The sharpest contraction is for gas powered generation, with a forecast annual average decline of 9.8 per cent between 2014 and 2022.[28] EnergyQuest agreed, expecting total domestic gas demand to fall from its peak of around 720 PJ in 2012 to 600 PJ by 2020.[29] In contrast, LNG demand is expected to rise from zero to around 1450 PJ by that time, accounting for around 70 per cent of total gas demand in eastern Australia.[30]

The net impact of these dynamic shifts in domestic demand and supply are difficult to predict, but east coast gas prices are likely to continue rising until at least 2014, and remain significantly above cost until all Queensland LNG projects are fully producing from their own reserves (around 2019–20).

Policy makers are implementing reforms to help alleviate pressures in the eastern gas market. The most advanced reform is a gas trading exchange at Wallumbilla, Queensland, set for launch in March 2014 (section 3.4.4). The exchange aims to alleviate bottlenecks in the tight Queensland gas market by facilitating short term gas trades.

In other developments, the Standing Council on Energy and Resources (SCER) consulted in 2013 on possible reforms to pipeline capacity trading to promote trade in idle contracted capacity in the eastern gas market. Throughout the year, some pipelines have significant idle capacity that is contracted to gas retailers and industrial consumers. SCER consultations with industry identified stakeholder interest in improving access to this unused capacity via a transparent, market based mechanism. Capacity trading could make more efficient use of existing infrastructure by reallocating idle capacity and allowing the delivery of additional gas to the market. The reform may be particularly useful to small participants, which lack the scale to invest in transmission capacity.[31]

An AEMC scoping study published in September 2013 proposed consideration of further measures. These measures included strategically planning gas market development, refining spot market design, and streamlining the processes for making rule changes that affect gas spot markets.[32]

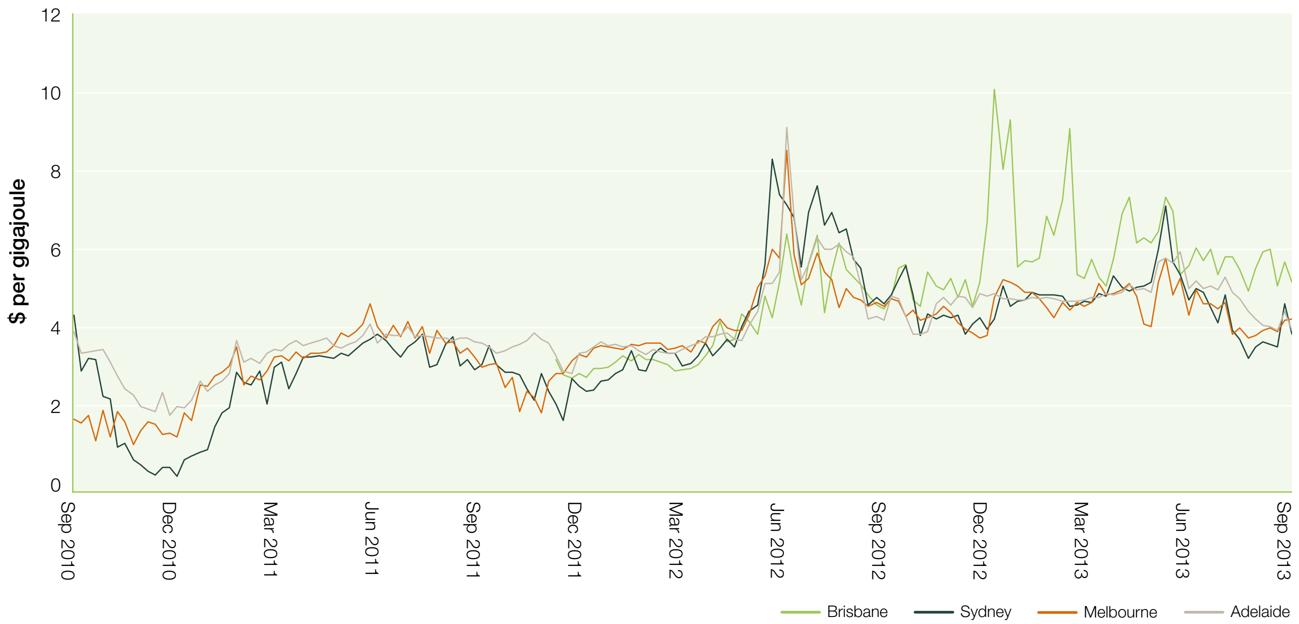
3.5.1 Spot market prices

The Victorian wholesale gas market and the short term trading market for Sydney, Adelaide and Brisbane establish spot gas prices. Sections 3.4.1–3.4.3 provide background on these markets.

Table 3.3 sets out average annual spot prices, while figure 3.7 illustrates weekly averages. Figure 3.8 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. Design differences between the 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 comparison, the data include estimates for Melbourne gas prices, based on the Victorian wholesale price plus the estimated cost of transmission pipeline delivery to the metropolitan hub.[33]

21 AEMO, *Energy update*, October 2013.
22 EnergyQuest, *Energy Quarterly*, August 2013, p. 19.
23 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.
24 See, for example, ACIL Allen Consulting, *NSW coal seam gas*, Report to the Australian Petroleum Production and Exploration Association (APPEA), 2013, p. 2.
25 EnergyQuest, *Energy Quarterly*, August 2013, p. 77.
26 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013, p.vi.
27 BREE, *Gas market report*, October 2013, p. 26.
28 AEMO, Gas Statement of Opportunities 2013, p.8.
29 EnergyQuest, *Energy Quarterly*, August 2013, p. 19.
30 AEMO, *Gas Statement of Opportunities 2013*, p.8.
31 Standing Council on Energy and Resources officials, *Regulation impact statement: gas transmission pipeline capacity trading*, Consultation Paper, 15 May 2013.
32 AEMC, *Taking stock of Australia's east coast gas market, Information paper*, September 2013; K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.
33 The Sydney data in table 3.3 and figures 3.7 exclude the 1 November 2010 price of $150 per gigajoule, which data errors caused.

Figure 3.7
Spot gas prices—weekly averages



Notes (table 3.3 and figure 3.7): Volume weighted ex ante prices. Sydney, Adelaide and Brisbane data are short term trading market prices. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's transmission withdrawal tariff for the two Melbourne metropolitan zones. The Brisbane price for 2011–12 covers the period 1 December 2011 (market start) to 30 June 2012.

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

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

	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
2012–13	5.92	5.20	4.86	5.09
2011–12	3.51	3.45	3.65	3.79
2010–11		2.37	2.74	3.17

Average daily spot prices for gas in all markets were significantly higher in 2012–13 than in the previous year (table 3.3). Average prices rose by 69 per cent in Brisbane,[34] 51 per cent in Sydney, 33 per cent in Melbourne and 34 per cent in Adelaide. They ranged from $4.86 (Melbourne) to $5.92 (Brisbane).

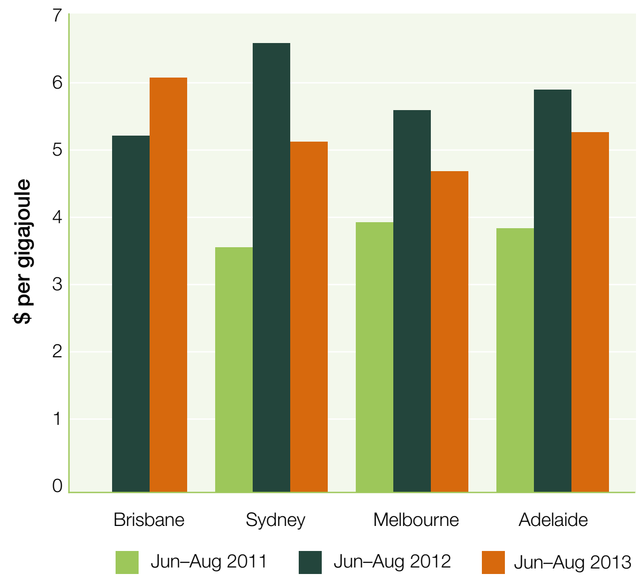
Spot gas prices have trended higher since 2010, when outcomes below $3 per gigajoule were typical. A step change occurred during winter 2012, when the introduction of carbon pricing on 1 July 2012 improved the cost competitiveness of gas powered electricity generation. The closure of significant coal fired generation capacity around this time (section 1.3.3) appears to have reinforced a rise in demand for gas.

Additionally, the AER detected market participants driving prices higher than expected in the early weeks of carbon pricing. This influence was indicated by significant variations between forecast prices, ex ante prices and ex post prices. Further, the quality of demand forecasting by participants was poor on a number of days. This period also coincided with the usual seasonal peaks in demand that occur in winter, and with a significant tightening in the contract market for gas in eastern Australia (section 3.5). In combination, these factors caused winter gas prices in 2012 to rise to above $5 per gigajoule in all spot markets, with Sydney prices averaging almost $7 per gigajoule (figure 3.8).

Gas prices eased during spring 2012, settling at around $4–5 per gigajoule. They generally remained in that range in 2013. But market volatility was considerable, with an above average frequency of price spikes. Notably, Brisbane prices diverged markedly from prices in other markets in 2013, with weekly averages as high as $10 per gigajoule in January 2013. This development mirrored higher contract prices in Queensland (section 3.5).

34 Brisbane prices rose by 69 per cent when comparing average 2012–13 prices with average prices over the seven month period in 2011–12 (1 December 2011 to 30 June 2012) in which the Brisbane market operated. Brisbane prices rose by 82 per cent when comparing average prices for December 2012 to June 2013 with the corresponding period in the previous year.

Figure 3.8
Spot gas prices—winter



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 for the two Melbourne metropolitan zones.

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

Sydney prices briefly spiked in June 2013 during a week of cold temperatures and high demand. But winter demand was mostly subdued, resulting in prices for all hubs easing slightly after June 2013. In Victoria, a mostly mild winter and a reduction in gas powered generation contributed to an overall 8.8 per cent decrease in gas demand during winter 2013.[35] But prices in all hubs remained well above longer term averages. Additionally, Brisbane prices remained significantly higher than elsewhere.

Overall, winter prices were lower in 2013 than in the previous year in Melbourne (16 per cent lower), Sydney (22 per cent) and Adelaide (10 per cent). Prices peaked at $9.50 per gigajoule in Sydney (on 25 June), $6.02 per gigajoule in Adelaide (on a number of days in June and July) and $7.31 per gigajoule in Melbourne (on 24 June). Brisbane reflected a different trend: its average winter price was 16 per cent higher in 2013 than in 2012, peaking at $8.01 per gigajoule on 23 June.

35 AEMO, *Energy update*, October 2013.

3.6 Upstream competition

An interconnected transmission pipeline system links the major gas basins in southern and eastern Australia (chapter 4). While gas tends to be purchased from the closest possible source to minimise transport costs, pipeline interconnection 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 served by multiple transmission pipelines from multiple gas basins; by contrast, Brisbane is served by only one pipeline (Roma to Brisbane).

The bulletin board (section 3.4.3) provides real-time information on the gas market, to enhance transparency and 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 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. Victorian gas exports to New South Wales, via the Eastern Gas Pipeline and the New South Wales – Victoria Interconnect, were 46 per cent higher during winter 2013 than a year earlier.[36]
- 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 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.

36 AEMO, *Energy update*, October 2013.

The extent to which interconnection benefits customers depends on a range of factors, including the availability of gas and pipeline capacity from alternative sources. In particular, capacity constraints limit access to some pipelines. Access seekers must decide whether to try to negotiate a capacity expansion. For a covered pipeline, the regulator may be asked to arbitrate a dispute over capacity expansions.

3.7 Gas storage

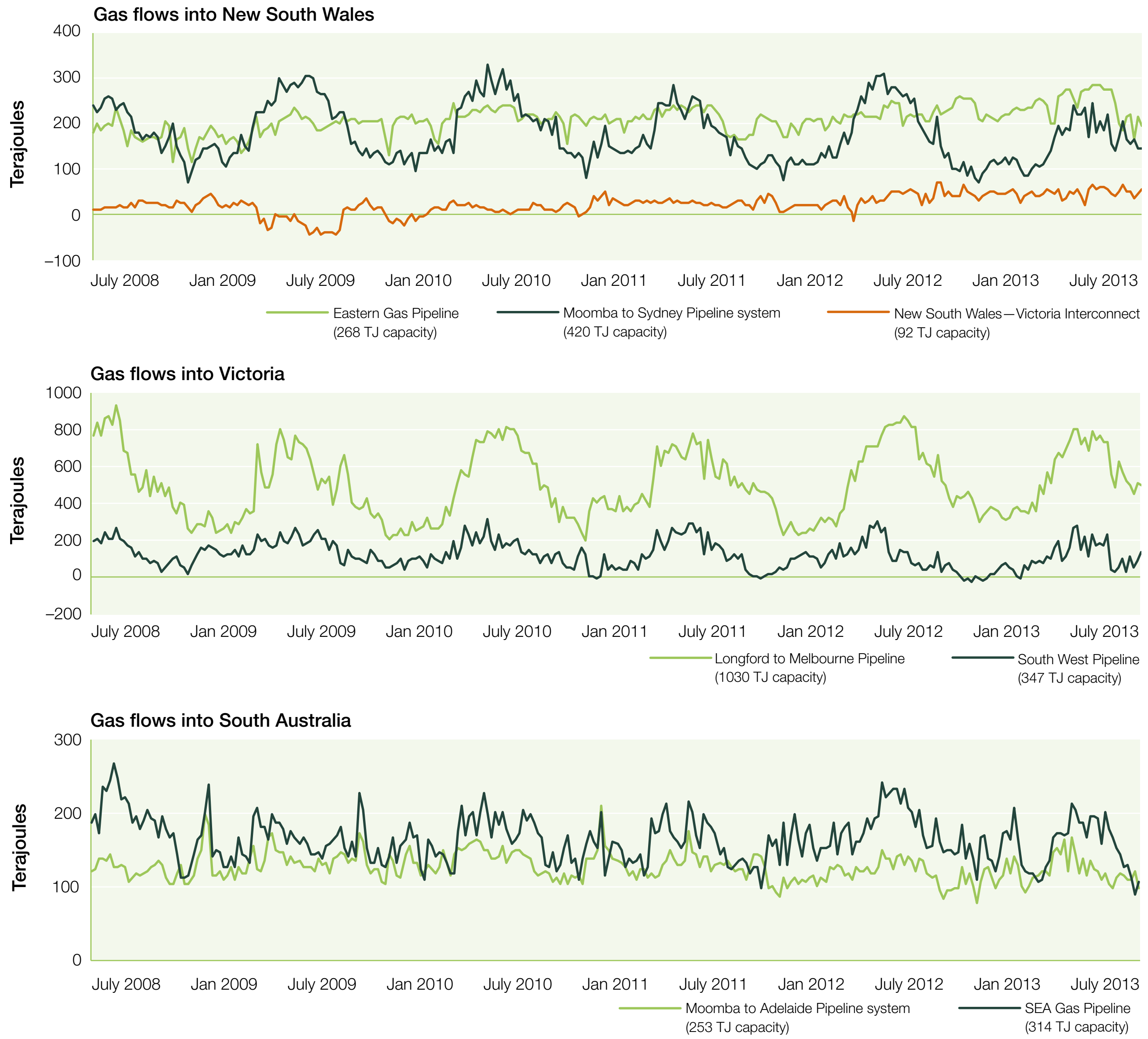
Gas can be stored in its natural state in depleted underground reservoirs and pipelines, or post liquefaction as LNG in purpose built facilities. Given Australia's increasing reliance on gas powered electricity generation, gas storage enhances the security of energy supply. It does so by allowing for 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 it provides retailers with a hedging mechanism if gas demand is significantly above forecast.

Conventional gas storage facilities are located in Victoria, Queensland 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 Energy to manage its gas supply during seasonal variations in summer and winter. EnergyQuest estimated the facility held around 18 PJ in storage in June 2013.[37]

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 near Newcastle to secure supply during peak periods and supply disruptions. Due to be completed by 2015, the facility will have a peak supply rate of 120 terajoules per day.

37 Energy Quest, *Energy Quarterly*, August 2013, p. 111.

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).