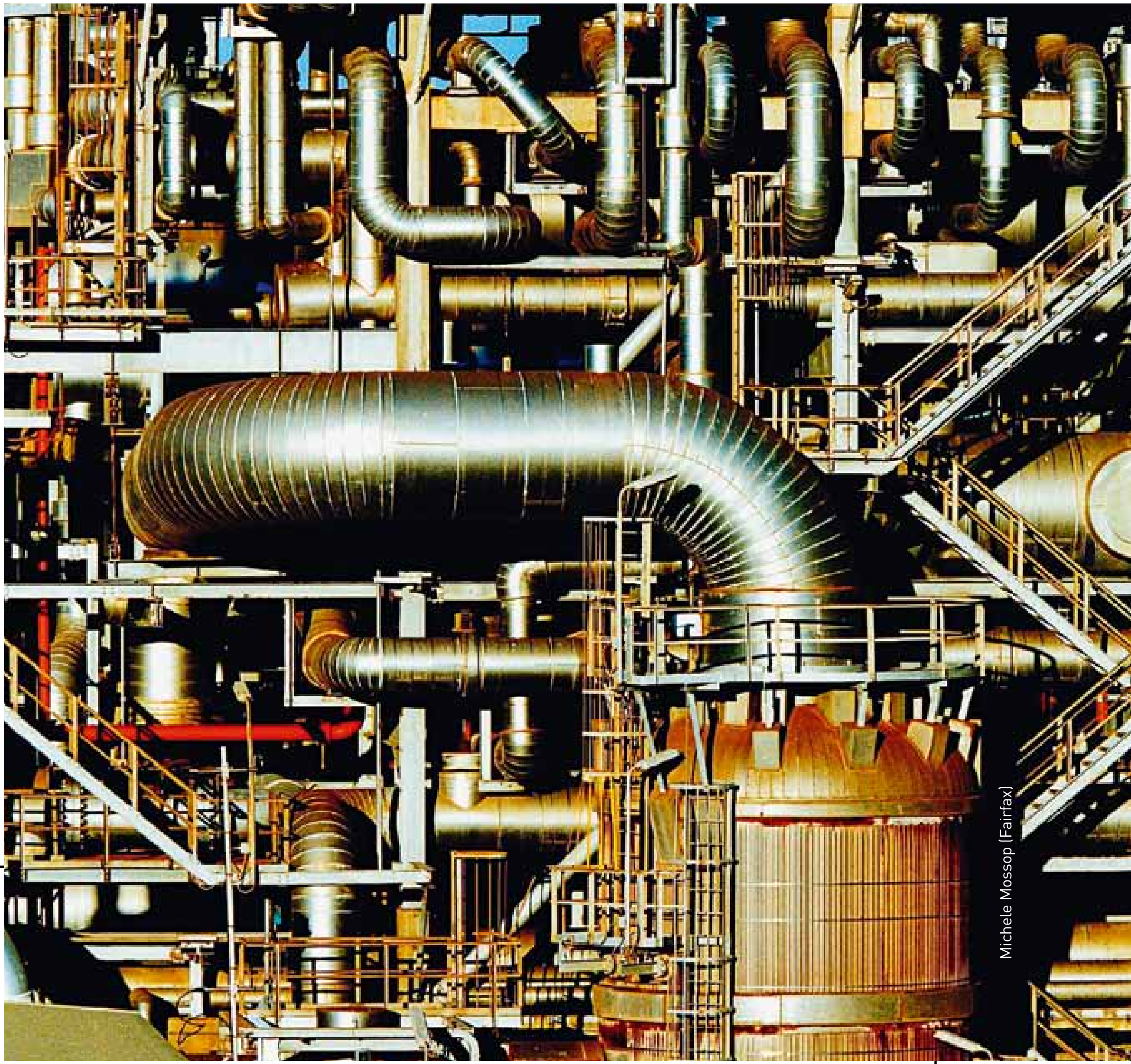

Michele Mossop (Fairfax)

3 GAS

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).

Gas is produced both for domestic markets and for export as liquefied natural gas (LNG). High pressure transmission pipelines transport gas over long distances to domestic markets. 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.

This chapter covers gas production, wholesale market arrangements, and the transmission and distribution pipeline sectors. While the chapter focuses on domestic markets in eastern Australia in which the Australian Energy Regulator (AER) has regulatory responsibilities,[1] it also covers gas markets in Western Australia and the Northern Territory, and LNG export markets. Chapter 4 considers the retailing of gas to small customers.

3.1 Reserves and production

In August 2011 Australia's proved and probable (2P) gas reserves stood at around 115 000 petajoules (PJ), comprising 77 000 PJ of conventional natural gas and 38 000 PJ of CSG.[2] Total proved and probable reserves increased by around 9 per cent in 2010–11. CSG reserves in Queensland and New South Wales rose by 33 per cent.

Australia produced 2030 PJ of gas in 2010–11, of which around 53 per cent was for the domestic market. The CSG share of production for the domestic market rose from 19 per cent in 2009–10 to 21 per cent in 2010–11. Around 47 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 is likely to increase in the future, with the development of major LNG projects in Queensland and Western Australia (section 3.2.1).

The Australian Energy Market Operator's (AEMO) 2011 *Gas statement of opportunities* projected gas reserves in eastern and south eastern Australia would be sufficient to meet domestic and LNG export demand over the next 20 years under a range of modeled scenarios.[3]

3.1.1 Geographic distribution

Table 3.1 sets out the geographic distribution of Australia's gas reserves in August 2011 and production in 2010–11. Figure 3.1 illustrates the locations of major gas basins and the transmission pipelines used to ship gas from the basins to domestic markets.

Western Australia's offshore Carnarvon Basin holds the majority (about 60 per cent) of Australia's proved and probable gas reserves. It supplies almost one-third of Australia's domestic market and 98 per cent of Australian gas for LNG export.

The Bonaparte Basin along the north west coast contains around 1 per cent of Australia's gas reserves. While its 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 displaced the Amadeus Basin as the main source of domestic gas for the Territory. Production from the Amadeus Basin decreased from 10.2 PJ in

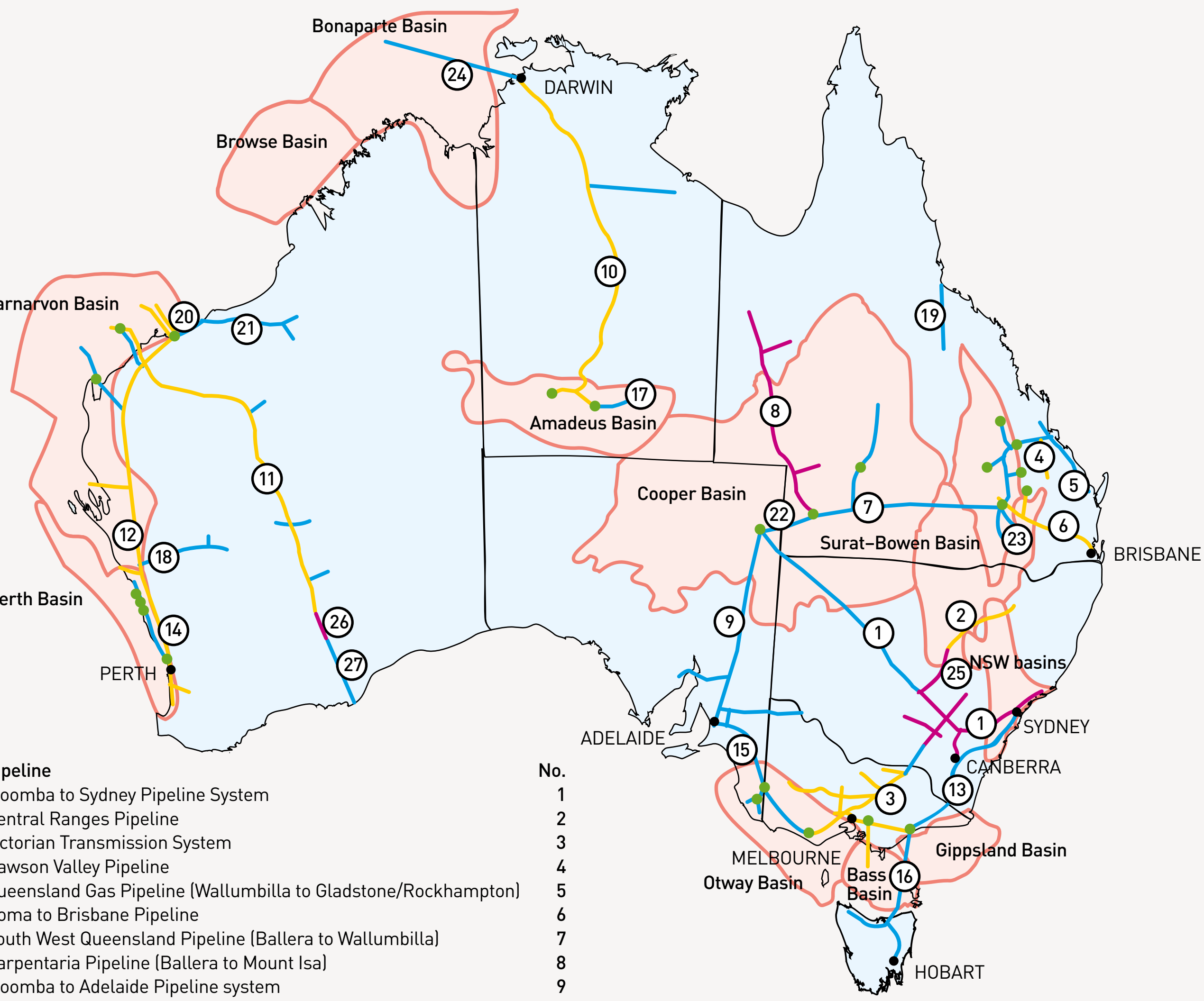
1 The AER has compliance and enforcement responsibilities—under parts 18–20 of the National Gas Rules—in relation to the Natural Gas Market Bulletin Board, the Victorian wholesale gas market and the short term trading market that commenced operating in Sydney and Adelaide in 2010.

2 EnergyQuest, *Energy Quarterly*, August 2011.

3 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.

Figure 3.1

Australian gas basins and transmission pipelines



Pipeline	No.
Moomba to Sydney Pipeline System	1
Central Ranges Pipeline	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 system	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, 2011

GAS BASIN	PRODUCTION (YEAR TO JUNE 2011)		PROVED AND PROBABLE RESERVES[2] (AUGUST 2011)	
	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS[1]				
WESTERN AUSTRALIA				
Carnarvon	344	31.8	68 856	59.6
Perth	4	0.3	42	0.0
NORTHERN TERRITORY				
Amadeus	2	0.1	141	0.1
Bonaparte	20	1.8	1 184	1.0
EASTERN AUSTRALIA				
Cooper (South Australia – Queensland)	96	8.9	1 373	1.2
Gippsland (Victoria)	252	23.3	4 571	4.0
Otway (Victoria)	106	9.8	939	0.8
Bass (Victoria)	18	1.6	268	0.2
Surat–Bowen (Queensland)	10	1.0	183	0.2
Total conventional natural gas	851	78.6	77 557	67.2
COAL SEAM GAS				
Surat–Bowen (Queensland)	225	20.8	34 986	30.3
New South Wales basins	6	0.6	2 910	2.5
Total coal seam gas	231	21.4	37 896	32.8
AUSTRALIAN TOTALS	**1082**	**100.0**	**115 453**	**100.0**
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	933			
Bonaparte (Northern Territory)	14			
Total liquefied natural gas	948			
TOTAL PRODUCTION	**2030**			

1. Conventional natural gas reserves include LNG and ethane.
2. 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 2011.

2009–10 to 1.6 PJ in 2010–11, while production from the Blacktip field in the Bonaparte Basin increased from 8.5 PJ to 19.6 PJ over the same period.

Eastern Australia contains around 39 per cent of Australia's gas reserves, of which the majority are CSG reserves in the Surat–Bowen Basin in Queensland. The basin accounts for over 30 per cent of national gas reserves and supplies over 20 per cent of the domestic market. The Gippsland Basin off coastal Victoria supplies 23 per cent of the domestic market. While reserves in the Cooper Basin in central Australia are in long term decline, they increased by 19 per cent in the year to June 2011. Production in Victoria's offshore Otway Basin (10 per cent) has risen significantly since 2004, but was steady in 2010–11.

Production of CSG has risen exponentially since 2004, with the bulk of activity occurring in the Surat–Bowen Basin, which extends from Queensland into northern New South Wales. While the basin is an established supplier of conventional natural gas, it also contains most of Australia's proved and probable CSG reserves. In New South Wales, commercial production of CSG began in 1996 in the Sydney Basin and more recently in the Gunnedah Basin.

While CSG is produced only in Queensland and New South Wales, it is the fastest growing gas production sector. CSG production rose by around 17 per cent to 231 PJ in 2010–11, accounting for over 32 per cent of gas production in eastern Australia. CSG's share of Australia's proved and probable reserves increased from 27 per cent at August 2010 to 33 per cent at August 2011.[4]

3.2 Domestic and international demand

Australia consumed around 1082 PJ of gas in 2010–11 for a range of industrial, commercial and domestic applications. Gas is increasingly used for electricity generation, mainly to fuel intermediate and peaking generators. The residential sector uses gas mainly for heating, hot water and cooking.

The consumption profile varies across the jurisdictions. Gas is widely used in most jurisdictions for industrial manufacturing. 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. The reserves may be sourced through the LNG owner's interests in a gas field, a joint venture arrangement with a gas producer, or long term gas supply contracts.

Australia has operating LNG export projects in Western Australia's North West Shelf and Darwin. Exports of Australian produced LNG in 2010–11 rose by 11 per cent to 17.3 million tonnes,[5] and major players are continuing to expand capacity:

- Woodside's 4.3 million tonne per year Pluto project (Carnarvon Basin) is nearing completion and will become Australia's third operational LNG project. The estimated development cost is $14.9 billion. The first exports are expected in March 2012.
- Chevron's $43 billion Gorgon project (Carnarvon Basin) is scheduled to begin operation in 2014 and will produce around 15 million tonnes of LNG per year. The project partners have signed long term sales agreements with international buyers. A final decision on Chevron's $25 billion Wheatstone project (foundation capacity of 8.9 million tonnes per year) was made in September 2011. The project's first LNG would be produced in 2016.
- Shell's $10–$13 billion floating LNG project (Browse Basin) is under construction and is expected to commence production in 2016.
- Inpex and Total are expected to make a final investment decision before the end of 2011 on the $23 billion Ichthys LNG project (Browse Basin).

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 is underway, and a fourth is at the planning stage:

- The $15 billion Curtis LNG project (BG Group) is under construction. It will initially produce 8.5 million tonnes per year, with potential capacity of 12 million tonnes. The first exports are expected in 2014.
- The $16 billion Gladstone LNG project (Santos, Petronas, Total and Kogas) is under construction. It will initially produce 7.8 million tonnes per year, with potential capacity of 10 million tonnes. The first exports are expected in 2015.

4 All data on gas production, consumption and reserves are sourced from EnergyQuest, *Energy Quarterly*, August 2011.

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

- The Australia Pacific LNG project (Origin Energy, ConocoPhillips and Sinopec) has commenced construction. It will initially produce 4.3 million tonnes per year, with first exports expected in 2015.
- The Arrow LNG project (Shell and PetroChina) is at the planning stage. It would produce 16 million tonnes per year, with first exports expected in 2017.

AEMO forecast in its 2011 *Gas statement of opportunities* that LNG exports from Queensland would likely exceed total domestic gas demand in eastern and south eastern Australia by 2016. It also forecast they would exceed the total energy that the National Electricity Market is projected to produce in that year.[6]

3.3 Industry structure

Six major producers met 65 per cent of domestic gas demand in 2010–11: BHP Billiton, Santos, 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 3.2 illustrates estimates of market share in gas production for the domestic market in the major basins. Table 3.2 sets out market shares in proved and probable gas reserves (including reserves available for export) at August 2011.

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 (32 per cent), Shell (18 per cent) and ExxonMobil (15 per cent) have the largest gas reserves in the basin, given their equity in the Gorgon project.

Woodside (25 per cent) and Apache Energy (23 per cent) are the largest producers for Western Australia's domestic market. Santos (13 per cent), BP and Chevron (10 per cent each), and BHP Billiton and Shell (6 per cent each) have significant market shares.

Gas for the Northern Territory was historically sourced from the Amadeus Basin and produced by Santos and Magellan. The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea, which is now the dominant source of gas supply to the Territory. Eni owns over 80 per cent of Australian reserves in the basin.

In eastern Australia, control of the Gippsland and Cooper basins is concentrated among a handful of established producers. A joint venture led by Santos (65 per cent) dominates production in South Australia's Cooper Basin. The other participants are Beach Petroleum (21 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 94 per cent of production in the Gippsland Basin, which is the largest producing basin in eastern Australia. Nexus, which began production from the Longtom gas project in October 2009, has acquired a 6 per cent market share.

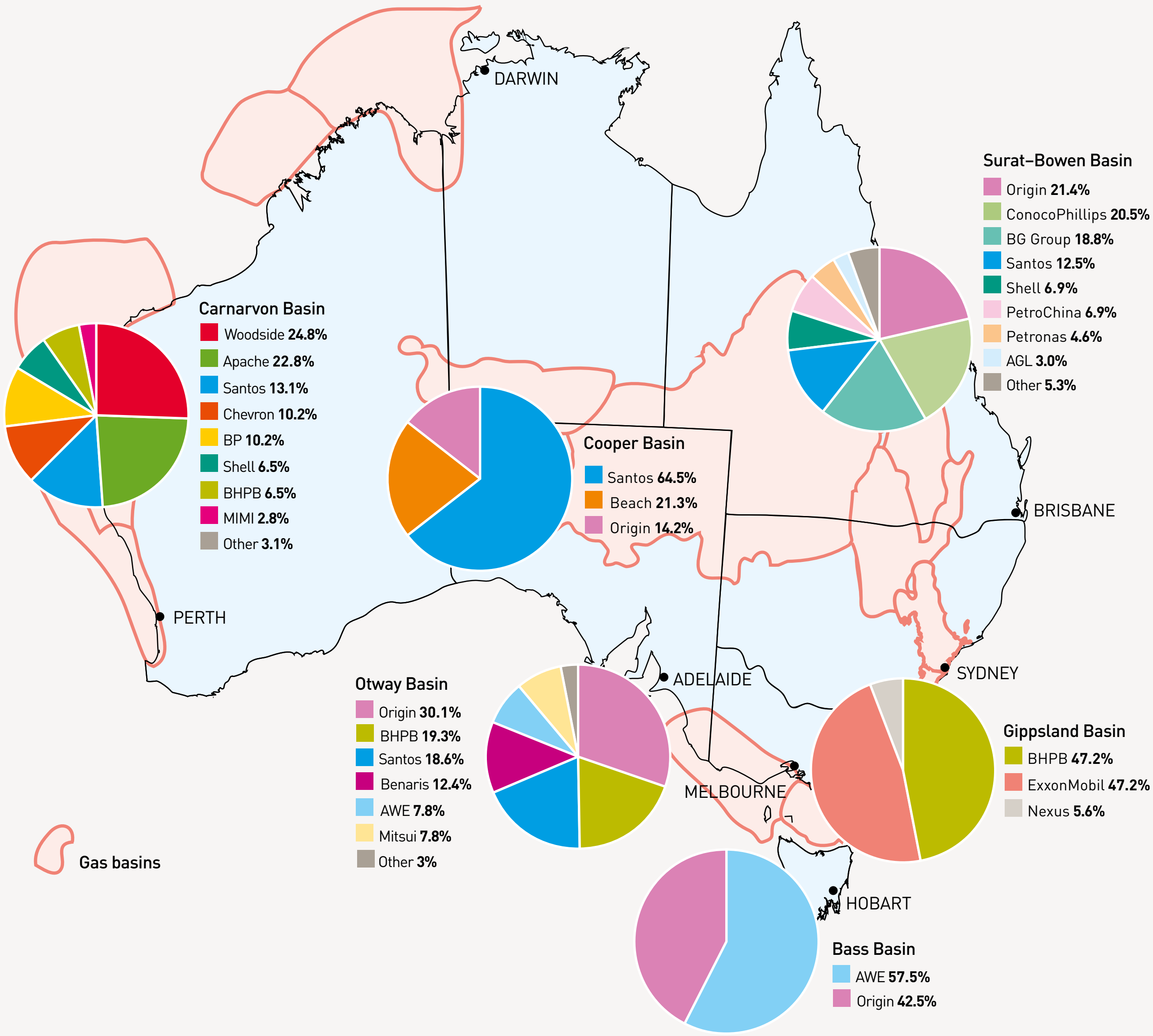
The Otway Basin off south west Victoria has a more diverse ownership base, with Origin Energy (30 per cent), BHP Billiton (19 per cent) and Santos (19 per cent) accounting for the bulk of production. The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration.

The growth of the CSG industry has led to considerable new entry in Queensland's Surat–Bowen Basin over the past decade. The largest producers are Origin Energy (21 per cent), ConocoPhillips (20 per cent), BG Group (19 per cent), Santos (12 per cent), Shell and PetroChina (7 per cent each), Petronas (5 per cent) and AGL Energy (3 per cent). These businesses also own the majority of gas reserves in the basin.

6 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.

7 EnergyQuest, *Energy Quarterly*, August 2011.

Figure 3.2
Market shares in domestic gas production, by basin, 2010–11



Notes:

Excludes liquefied natural gas.

Some corporate names are shortened or abbreviated.

Data source: EnergyQuest 2011 (unpublished data).

Table 3.2 Market shares in proved and probable gas reserves, by basin, 2011 (per cent)

COMPANY	CARNARVON (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	32.2														19.2
Shell	17.9				9.1										13.4
ExxonMobil	14.9											43.8			10.6
Woodside	12.3														7.3
BG					22.7										6.9
Origin		62.1			14.6	13.1							36.1	41.0	5.0
Santos	1.2		2.4	64.4	6.2	63.2		80.0				4.8	16.1		4.8
BHPB	4.4											43.8	15.7		4.5
ConocoPhillips			11.9		14.2										4.5
BP	4.8														2.9
PetroChina					9.1										2.8
Apache	3.8														2.3
MIMI	3.6														2.2
AGL					3.3				100.0	100.0	100.0				1.8
Sinopec					5.0										1.5
Petronas					3.9										1.2
Total					3.9										1.2
CNOOC	1.2														1.1
Eni			81.5												0.8
Tokyo Gas	1.0				0.3										0.7
Kufpec	1.2														0.7
Kogas					2.1										0.7
Osaka Gas	0.7														0.4
Mitsui					1.1								7.2		0.4
Metgasco							100.0								0.4
Molopo					1.0										0.3
Nexus												7.6			0.3
TRUenergy								20.0							0.3
Beach						21.8									0.3
Kansai Electric	0.4														0.3
AWE		37.9											7.2	59.0	0.2
Other	0.3		4.3	35.6	3.4	1.9							17.7		1.1
TOTAL (PETAJOULES)	**68 856**	**42**	**1184**	**141**	**35 169**	**1373**	**428**	**1520**	**669**	**151**	**142**	**4571**	**939**	**268**	**115 453**

Notes:

Based on 2P (proved and probable) reserves at August 2011.

Some corporate names are shortened or abbreviated. Not all minority owners are listed.

Source: EnergyQuest 2011 (unpublished data).

Figure 3.3 shows changes in market shares of gas reserves in the Surat–Bowen Basin between 2008 and 2011. The changes reflect both mergers and acquisitions, and the development of new projects. In 2008 three entities owned about 75 per cent of reserves (Origin Energy with 35 per cent, Santos with 22 per cent and Queensland Gas with 18 per cent). In contrast, the three largest players in 2011 own about 52 per cent of reserves (BG Group with 23 per cent, Origin Energy with 15 per cent and ConocoPhillips with 14 per cent).

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. The 2009 and 2010 editions of the AER's *State of the energy market* report listed proposed and successful acquisitions from June 2006 to October 2010. Activity from that time until October 2011 included the following:

- In July 2011 Santos acquired Eastern Star Gas, which has CSG assets in the Gunnedah Basin (New South Wales). It subsequently sold a 20 per cent interest to TRUenergy. The entities will develop the project as joint venture partners.
- In August 2011 Sinopec Group acquired a 15 per cent share in the Australia Pacific LNG project (Queensland).
- In September 2011 Arrow Energy (Shell and PetroChina) announced that it had agreed to pay $535 million for gas explorer Bow Energy, to source additional CSG resources for its Queensland LNG project.

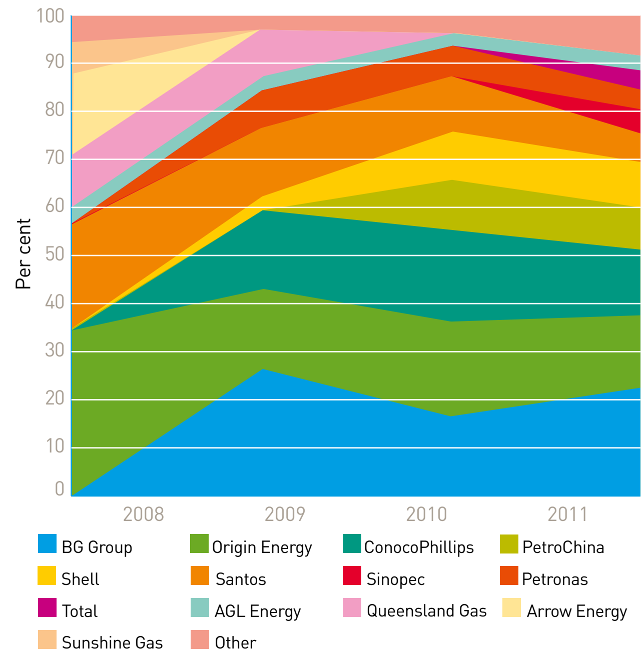
3.3.3 Vertical integration

The increasing use of gas as a fuel for electricity generation creates synergies for energy retailers to manage price and supply risk through equity in gas production and gas fired electricity generation. The energy retailers Origin Energy and AGL Energy each have substantial interests in gas production and electricity generation:

- Origin Energy is a leading energy retailer and is expanding its electricity 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.
- AGL Energy is a leading energy retailer and a major electricity generator in eastern Australia. A relative newcomer to gas production, it began acquiring CSG interests in Queensland and New South Wales in 2005.

TRUenergy, a third major retailer and generator in eastern Australia, acquired an interest in New South Wales CSG reserves in 2011.

Figure 3.3
Market shares in proved and probable reserves, Surat–Bowen Basin, 2008–11



Data source: EnergyQuest 2008–11 (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 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.

3.4.1 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. The *State of the energy market 2009* report provides background on the market's operation (pp. 246–7). In summary, 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, this price applies to only net positions—the difference between a participant's scheduled gas deliveries into and out of the hub. AEMO can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term constraints.

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 3.5.3 notes recent price activity.

3.4.2 Short term trading market

A short term trading market—a wholesale spot market for gas—is being progressively implemented at selected hubs that link transmission pipelines and distribution systems in southern and 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. Market participants include energy retailers, power generators and other large scale gas users. 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 has retained its own spot market for gas (section 3.4.1).

The short term trading market allows participants to buy or sell some, or all, of their gas requirements on a spot basis without long term sales contracts. The market provides general price guidance as well as a platform for trading (including secondary trading) and demand side response by users. It operates in conjunction with longer term gas supply and transportation contracts. The AER monitors and enforces compliance with the market Rules (section 3.6).

The market sets a daily (ex ante) clearing price at each hub, based on scheduled withdrawals and day-ahead offers by gas shippers to deliver gas. All gas supplied according to the market schedules is settled at this price. When participants deviate from their scheduled gas deliveries or withdrawals, AEMO maintains physical system balance by procuring additional gas (market operator services). Gas procured under this balancing mechanism is settled primarily through deviation payments and charges on the parties responsible for the imbalances.

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

- In the short term trading market, AEMO operates the financial market but does not operate the actual flow of gas (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 commodity gas and 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 covering major gas production plants, storage facilities, demand centres and transmission pipelines in southern and 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 capacity and daily aggregated data on expected 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). The bulletin board is operated by AEMO, which also publishes an annual gas statement of opportunities to help industry participants plan and make commercial decisions on infrastructure investment.

3.5 Gas prices

Australian gas prices have historically been low by international standards. They have also been relatively stable, defined by provisions in long term supply contracts. In the United States and Europe, gas prices closely follow oil prices. Conversely, gas in Australia has generally been perceived as a substitute for coal and coal fired electricity. Australia's abundant low cost coal sources have effectively capped gas prices. The growth of LNG export capacity in Western Australia from the late 1980s led to the domestic market being increasingly exposed to international energy prices. A similar scenario may be unfolding on the east coast, with LNG exports expected to commence from Queensland in 2014.

3.5.1 Western Australia

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.

In 2011 a Western Australian parliamentary inquiry into domestic gas prices found the average price in domestic gas contracts in 2009–10 was $3.70 per gigajoule. But prices in new contracts ranged from $5.55 to $9.25 per gigajoule. The inquiry recommended initiatives to improve the efficiency of the wholesale market by enhancing transparency, competition and liquidity. Several initiatives mirror 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.[8]

3.5.2 Eastern Australia

An interconnected transmission pipeline network in southern and eastern Australia 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 ACT. EnergyQuest reported east coast prices for conventional gas under existing long term contracts in 2011 were around $3.50–4.00 per gigajoule.[9]

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

9 EnergyQuest, *Energy Quarterly*, August 2011, p. 94.

An interaction of several factors affects the gas supply–demand balance and price outcomes in eastern Australia. On the supply side, rising CSG production in Queensland and improved pipeline interconnection among the eastern gas basins have enhanced the flexibility of the market to respond to customer demand. CSG production in Queensland and New South Wales rose by 17 per cent in 2010–11.[10] New transmission pipelines, such as the QSN Link (commissioned in 2009), provide the physical capacity to transport the gas to southern markets.

The development of LNG projects in Queensland is also producing 'ramp-up' gas that is being diverted to the domestic market until the projects are commissioned. Once a CSG well is in production, it is generally difficult to shut it in without having to start the process again. This ramp-up gas is being made available at relatively low prices.[11]

Aside from LNG exports, domestic factors are putting upward pressure on demand. Rising investment in gas fired power stations is a key driver. Gas powered electricity generation represents around 24 per cent of domestic gas demand in eastern and southern Australia.[12] While output from gas powered generation fell across the National Electricity Market (NEM) by 10 per cent in 2010–11 (mainly offset by an increase in wind generation),[13] the introduction of carbon pricing will drive greater reliance on gas powered generation in the medium to long term. AEMO's 2011 *Gas statement of opportunities* forecast gas powered generation would be the largest component of domestic demand growth in the next 20 years.[14]

Expanding CSG production and the ramp-up of LNG capacity are constraining short term gas prices in Queensland, which EnergyQuest reported in August 2011 were typically below $2 per gigajoule.[15] Queensland's 2011 *Gas market review* found supplies of ramp-up gas would likely constrain short term prices until LNG exports commence.[16]

However, the likely diversion of gas resources for LNG export may put upward pressure on Queensland prices from about 2014.[17] EnergyQuest noted the focus on developing LNG projects meant, while short term prices were low, few long term domestic gas contracts were available. It considered Queensland prices could move towards $7 per gigajoule for new long term domestic contracts.[18]

AEMO similarly noted the development of an east coast LNG industry may result in domestic gas prices rising towards parity with international prices. It noted, for example, many large producers in 2011 were securing sufficient reserves to enter LNG supply contracts with overseas customers, which over time may put pressure on domestic gas availability. It reported new contract prices in 2011 may be rising towards $5 per gigajoule.[19]

Queensland's 2011 *Gas market review* predicted Queensland domestic gas prices would rise to $5–8 per gigajoule by 2016, with the high end of this range being likely. It predicted prices would likely rise slightly later in the southern states than in Queensland.[20]

3.5.3 Spot market prices

The spot markets in Victoria (from 1999), Sydney and Adelaide (from September 2010) and Brisbane (from December 2011) provide data on short term gas prices. In the Victorian market (section 3.4.1), volumes can range from around 300 to 1200 terajoules per day. While the market accounts for only about 10–20 per cent of

10 EnergyQuest, *Energy Quarterly*, August 2011, p. 60.
11 EnergyQuest, 'Australia's natural gas markets: connecting with the world,' in AER, *State of the energy market 2009*.
12 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
13 EnergyQuest, *Energy Quarterly*, August 2011, p. 97.
14 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
15 EnergyQuest, *Energy Quarterly*, August 2011, p. 94.
16 Queensland Department of Employment, Economic Development and Innovation, *2011 gas market review Queensland*, 2011, p. 42.
17 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
18 EnergyQuest, *Energy Quarterly*, August 2011.
19 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
20 Queensland Department of Employment, Economic Development and Innovation, *2011 gas market review Queensland*, 2011, pp. 42–3.

wholesale volumes in Victoria, its price outcomes are widely used as a guide to underlying contract prices.

Victorian gas prices tended to ease after 2008. Reasons for the easing included an expansion of the Victorian Transmission System, which reduced capacity constraints. More recently, an apparent oversupply of contracted gas, along with an increase in the number of participating retailers, might have constrained bid prices in the market.

The Victorian market was relatively subdued throughout 2010, with prices in the first quarter (and the early part of the fourth quarter) typically below $2 per gigajoule (figure 3.4). However, colder temperatures in 2011 led to higher prices. The daily volume weighted average price for 2010–11 was $2.45 per gigajoule, compared with $1.83 per gigajoule in 2009–10. Both outcomes are significantly lower than long term average prices.

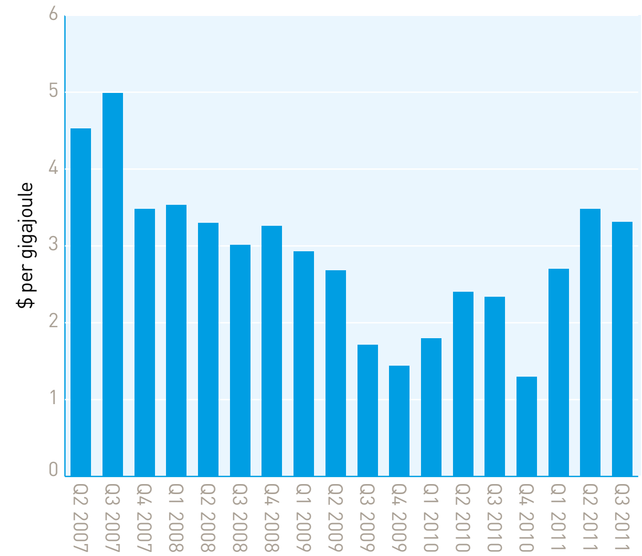
The short term trading market recorded some price instability in its early months, mainly due to data errors (figure 3.5). Average ex ante prices in the nine months from market start to 30 June 2011 were $2.87 per gigajoule in Sydney and $3.17 per gigajoule in Adelaide.

Design differences between the short term trading market and the Victorian market 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. Figure 3.5 includes price estimates for Melbourne, based on spot prices plus an estimate of transmission pipeline delivery to the metropolitan hub. It shows a reasonable degree of alignment across prices in the three capital cities.

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

Figure 3.4
Victorian spot gas prices—quarterly averages



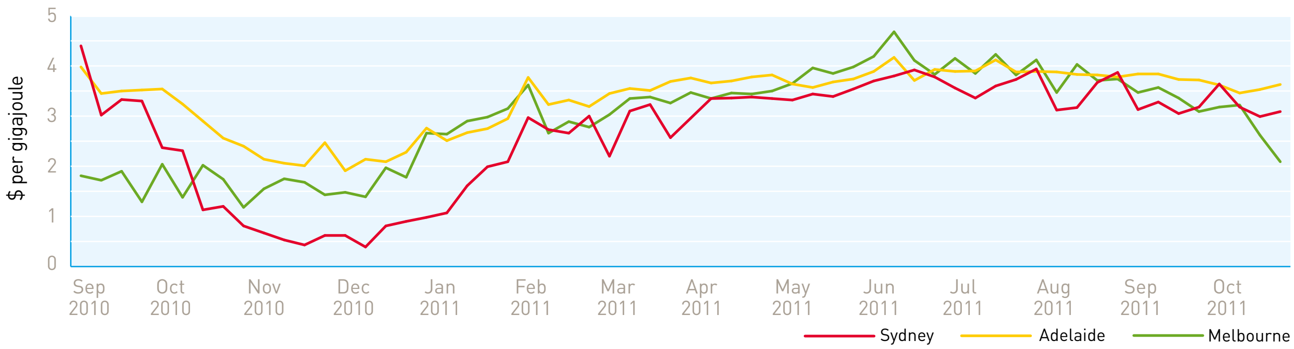
Sources: AEMO; AER.

Timely and accurate data and efficient pricing arrangements are essential to maintain confidence in gas markets and efficient investment in gas infrastructure and gas reliant infrastructure such as electricity generation. The AER monitors the spot markets and bulletin board to improve data provision and detect evidence of structural and market manipulation issues.

The AER's monitoring activity has helped improve data provision to the Victorian gas market and bulletin board. In the short term trading market, however, some failures to submit demand forecasts and data errors involving pipeline operators caused significant price impacts in the early months of operation. The AER began taking measures in 2011 to reduce participants' missing, late or erroneous data. The measures included meetings with the chief executive officers of major pipeline companies to outline the AER's views on 'good gas industry practice', and compliance audits of pipeline operators' systems for submitting data. More generally, the AER committed to the Standing Council on Energy and Resources (formerly the Ministerial Council on Energy) to monitor the market to detect any evidence of the exercise of market power.

Figure 3.5

Sydney, Adelaide and Melbourne spot gas prices—weekly averages



Notes:

Sydney and Adelaide data are weekly averages of the ex ante daily price in each hub. Ex ante prices are derived from demand forecasts in the short term trading market and form the main basis for settlement. The Sydney data exclude the 1 November 2010 price of $150 per gigajoule, which was caused by data errors.

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).

3.7 Gas transmission

Transmission pipelines transport gas from production fields to demand centres. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. Table 3.3 summarises Australia's major transmission pipelines; figure 3.1 illustrates pipeline routes.

Australia's gas transmission network covers over 20 000 kilometres. The construction of new pipelines and the expansion of existing facilities in the past decade created an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. This investment enhanced the competitive environment for gas producers, pipeline operators and gas retailers, and improved security of supply. While Western Australia and the Northern Territory have also had significant pipeline investment, they have no transmission interconnection with other jurisdictions.

3.7.1 Ownership of transmission pipelines

The AER *State of the energy market 2009* report traces the ownership history of Australia's gas transmission pipelines (section 9.2). The principal owners in the sector are:

- *APA Group*, which owns three pipelines in New South Wales (including the Moomba to Sydney Pipeline), the Victorian Transmission System, two major Queensland pipelines, three major Western Australian pipelines and a major Northern Territory pipeline. It also part owns the SEA Gas Pipeline. In December 2008 APA Group sold three pipelines to an unlisted investment vehicle, Energy Infrastructure Investments (EII), in which it retained a 20 per cent share. Since 2010 APA Group has increased its interest in Hastings Diversified Utilities Fund (see below) from about 4.5 per cent to 19.7 per cent. APA Group's portfolio includes gas distribution assets, both through direct ownership and via a 33 per cent stake in Envestra (section 3.9.1).
- *Jemena*, owned by *Singapore Power International*, which acquired a portfolio of gas transmission assets from Alinta in 2007. It owns and operates the Eastern Gas Pipeline, VicHub and the Queensland Gas Pipeline.

Table 3.3 **Major gas transmission pipelines**

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/D)	CONSTRUCTED	COVERED?
NORTH EAST AUSTRALIA					
North Queensland Gas Pipeline	Qld	391	108	2004	No
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	629	142	1989–91	No
Carpentaria Pipeline (Ballera to Mount Isa)	Qld	840	119	1998	Yes (light)
Berwyndale to Wallumbilla Pipeline	Qld	113		2009	No
Dawson Valley Pipeline	Qld	47	30	1996	Yes
Roma (Wallumbilla) to Brisbane	Qld	440	219	1969	Yes
Wallumbilla to Darling Downs Pipeline	Qld	205	400	2009	No
South West Queensland Pipeline (Ballera to Wallumbilla)	Qld	756	181	1996	No
QSN Link (Ballera to Moomba)	Qld–SA and NSW	180	212	2009	No
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	SA–NSW	2029	420	1974–93	Partial (light)
Central West Pipeline (Marsden to Dubbo)	NSW	255	10	1998	Yes (light)
Central Ranges Pipeline (Dubbo to Tamworth)	NSW	300	7	2006	Yes
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	795	268	2000	No
Victorian Transmission System (GasNet)	Vic	2035	1030	1969–2008	Yes
South Gippsland Natural Gas Pipeline	Vic	250		2006–10	No
VicHub	Vic		150 (into Vic)	2003	No
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	734	129	2002	No
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	680	303	2003	No
Moomba to Adelaide Pipeline	SA	1185	253	1969	No
WESTERN AUSTRALIA					
Dampier to Bunbury Pipeline	WA	1854	892	1984	Yes
Goldfields Gas Pipeline	WA	1427	150	1996	Yes
Parmelia Pipeline	WA	445	70	1971	No
Pilbara Energy Pipeline	WA	219	188	1995	No
Midwest Pipeline	WA	353	20	1999	No
Telfer Pipeline (Port Hedland to Telfer)	WA	443	25	2004	No
Kambalda to Esperance Pipeline	WA	350	6	2004	No
Kalgoorlie to Kambalda Pipeline	WA	44	20		Yes (light)
NORTHERN TERRITORY					
Bonaparte Pipeline	NT	287	80	2008	No
Amadeus Gas Pipeline	NT	1512	104	1987	Yes
Wickham Point Pipeline	NT	13		2009	No
Daly Waters to McArthur River Pipeline	NT	330	16	1994	No
Palm Valley to Alice Springs Pipeline	NT	140	27	1983	No

TJ/d, terajoules per day; CKI, Cheung Kong Infrastructure; REST, Retail Employees Superannuation Trust.

Notes:

Covered pipelines are subject to regulatory arrangements under the National Gas Law. The AER regulates covered pipelines in jurisdictions other than Western Australia; the Economic Regulation Authority is the regulator in Western Australia.

For covered pipelines subject to full regulation, valuation refers to the opening capital base for the current regulatory period. For non-covered pipelines, listed valuations are estimated construction costs, subject to availability of data.

VALUATION ($ MILLION)	CURRENT ACCESS ARRANGEMENT	OWNER	OPERATOR
160 (2005)	Not required	Victorian Funds Management Corporation	AGL Energy, Arrow Energy
	Not required	Jemena (Singapore Power International)	Jemena Asset Management
	Not required	APA Group	APA Group
70 (2009)	Not required	APA Group	APA Group
8 (2007)	2007–16	Anglo Coal 51%, Mitsui 49%	Anglo Coal
296 (2006)	2007–12	APA Group	APA Group
90 (2009)	Not required	Origin Energy	Origin Energy
	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 19.7%)	Epic Energy
165 (2009)	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 19.7%)	Epic Energy
835 (2003)	Not required	APA Group	APA Group
28 (1999)	Not required	APA Group	APA Group
53 (2003)	2005–19	APA Group	Jemena Asset Management
450 (2000)	Not required	Jemena (Singapore Power International)	Jemena Asset Management
524 (2007)	2008–12	APA Group	APA Group/AEMO
50 (2007)	Not required	DUET Group	Jemena Asset Management
	Not required	Jemena (Singapore Power International)	Jemena Asset Management
440 (2005)	Not required	Palisade Investment Partners	Tas Gas Networks
500 (2003)	Not required	APA Group 50%, REST 50%	APA Group
370 (2001)	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 19.7%)	Epic Energy
3375 (2011)	2010–15	DUET Group 80%, Alcoa 20%	DBP Transmission
439 (2009)	2010–15	APA Group 88.2%, Alinta Energy 11.8%	APA Group
	Not required	APA Group	APA Group
	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 19.7%)	Epic Energy
	Not required	APA Group 50%, Horizon Power (WA Govt) 50%	APA Group
114 (2004)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
45 (2004)	Not required	ANZ Infrastructure Services	WorleyParsons Asset Management
	Not required	APA Group	APA Group
170 (2008)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
92 (2011)	2011–16	APA Group	APA Group
36 (2009)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
	Not required	APA Group, Power and Water	APA Group
	Not required	Envestra (APA Group 33.1%, CKI 19.5%)	APA Group

Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden (figure 3.1). The covered portion became a light regulation pipeline in 2008. The listed valuation of the pipeline is that determined by the Australian Competition Tribunal for the regulatory period before the pipeline converted from full to light regulation.

'Current access arrangement' refers to access terms and conditions approved by the regulator.

Some corporate names are abbreviated or shortened.

Sources: Capacity: Office of Energy (Western Australia); National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites. Other data: access arrangements for covered pipelines; EnergyQuest, *Energy Quarterly* (various issues); corporate websites, annual reports and media releases.

- *Hastings Diversified Utilities Fund*, managed by a fund acquired by Westpac in 2005, which acquired Epic Energy's gas transmission assets in 2000. It owns the Moomba to Adelaide Pipeline, the Pilbara Energy Pipeline, the South West Queensland Pipeline and the QSN Link. APA Group holds a 19.7 per cent interest in Hastings.

The following ownership changes have occurred in the gas transmission sector since 2010:

- *Brookfield Infrastructure* acquired a portfolio of former Babcock & Brown gas transmission and distribution assets in December 2010, via a merger with Prime Infrastructure. In July 2011 Brookfield sold the Tasmanian Gas Pipeline to *Palisade Investment Partners*, and it sold a minority share in the Dampier to Bunbury Pipeline to *DUET Group* (raising DUET's equity in the pipeline from 60 to 80 per cent). AMP Capital Holdings and Macquarie Funds Group jointly own DUET Group.
- APA Group has significantly increased its equity in the pipeline sector.
  - In June 2011 it acquired the Northern Territory's Amadeus Gas Pipeline from a consortium of financial institutions. The pipeline had been leased to the Amadeus Gas Trust (in which APA Group held a 96 per cent interest) since 1986.
  - In November 2010 it acquired a further 16.7 per cent share in the SEA Gas Pipeline from International Power, raising its equity in the pipeline to 50 per cent.
  - Since 2010 it has progressively increased its equity in Hastings Diversified Utilities Fund (which owns Epic Energy) from around 4.5 per cent to 19.7 per cent, and in Envestra (which owns gas distribution assets) from 30.6 per cent to 33 per cent.
  - In March 2010 it acquired Queensland's Berwyndale to Wallumbilla Pipeline from AGL Energy.

3.7.2 Regulation of transmission pipelines

The National Gas Law and Rules set out the regulatory framework for the gas transmission sector. The AER regulates pipelines in jurisdictions other than Western Australia; the Economic Regulation Authority is the regulator in Western Australia.

The Law and Rules apply economic regulation provisions to covered pipelines. Various tiers of regulation apply, based on competition and significance criteria. The AER *State of the energy market 2009* report explains the coverage process and the different forms of economic regulation that may apply (section 9.3).

Table 3.3 indicates the coverage status of each major transmission pipeline. In summary, seven transmission pipelines are subject to *full regulation*, which requires a pipeline provider to periodically submit an access arrangement to the regulator for approval. An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service likely to be sought by a significant part of the market, and a reference tariff for that service. The regulator assesses the revenues needed to cover efficient costs (including a benchmark return on capital), then derives reference tariffs for the pipeline. The Rules allow for income adjustments from incentive mechanisms to reward efficient operating practices.

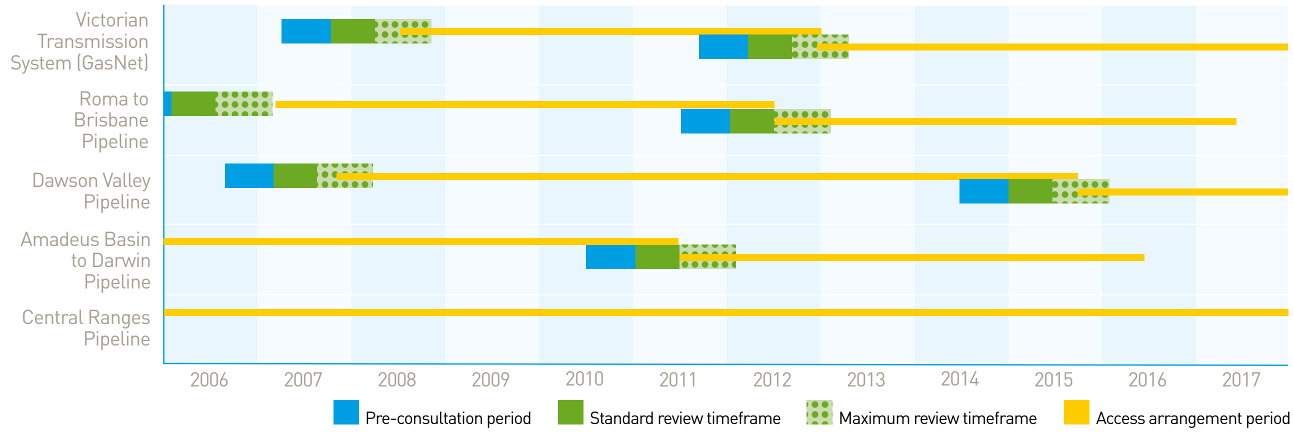
The AER currently regulates five transmission pipelines under full regulation.[21] Figure 3.6 shows indicative regulatory timeframes. An *Access arrangement guideline* (available on the AER website) details the regulatory process. Separate guidelines address dispute resolution and compliance with obligations under the Gas Law.[22] The AER's decisions on full regulation pipelines are subject to merits review by the Australian Competition Tribunal.

In September 2011 the AER submitted a Rule change proposal to the Australian Energy Market Commission (AEMC), recommending changes in the approach to determining the weighted average cost of capital for gas pipelines. The proposal aimed to create a more

21 The Economic Regulation Authority regulates two Western Australian transmission pipelines under full regulation.

22 AER, *Access arrangement guideline*, 2009; AER, *Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules*, 2008; AER, *Annual compliance guideline*, 2010.

Figure 3.6
Indicative timelines for AER determinations on gas transmission networks



Note: The timeframes are indicative. The standard review period begins when a network business submits an access arrangement proposal to the AER by a date specified in the previous access arrangement. The timeframes may vary if the AER grants a time extension for the proposal submission. An access arrangement period is typically five years, but a provider may apply for a different duration.

consistent framework between the electricity and gas sectors for determining the cost of capital. The proposed changes involve a periodic industry-wide review of the cost of capital parameters (box 2.1, chapter 2).

A pipeline may, in some circumstances, convert to *light regulation* without upfront price regulation. When light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. Four transmission pipelines are subject to light regulation: the Carpentaria Gas Pipeline in Queensland, the covered portions of the Moomba to Sydney Pipeline, the Central West Pipeline in New South Wales, and the Kalgoorlie to Kambalda Pipeline in Western Australia.

The Gas Law anticipates the potential for market conditions to evolve, and includes a mechanism for reviewing whether a particular pipeline needs economic regulation. The coverage of several major transmission pipelines has been revoked over the past decade. In addition, only one pipeline constructed in the past decade is covered.

The Gas Law also enables the federal Minister for Resources and Energy to grant a 15 year 'no coverage' determination for new pipelines in certain circumstances. In June 2010 the Minister granted such a determination for BG Group's Queensland Curtis LNG Pipeline from the Surat Basin to Curtis Island; construction of the pipeline commenced in 2010 (table 3.4).

3.7.3 Recent investment in transmission pipelines

Table 3.4 summarises major transmission investment (including expansions of existing pipelines) since 2010. It also lists major projects that in 2011 were under construction or had been announced for development.

Queensland's CSG industry continues to spur transmission pipeline investment. Epic Energy commissioned the QSN Link and expanded capacity on the South West Queensland Pipeline in 2009, to enable gas delivery between Queensland and the southern states. It is constructing a $760 million expansion of the pipelines, expected for completion in 2012. Also in Queensland, the planned development of LNG projects spurred plans for new transmission infrastructure to transport CSG to Gladstone for processing and export.

In Western Australia, new investment has centred on capacity expansions of the Dampier to Bunbury Pipeline, which is the major link between the state's North West Shelf and gas markets around Perth. A $690 million stage 5B expansion to add 120 terajoules per day of capacity was completed

Table 3.4 **Major gas transmission pipeline investment since 2010**

PIPELINE	LOCATION	OWNER/ PROPONENT	SCALE	COST ($ MILLION)	COMPLETION DATE
COMPLETED					
NORTH EAST AUSTRALIA					
Queensland Gas Pipeline expansion	Qld	Jemena	Expansion from 79 TJ/d to 140 TJ/d	112	2010
SOUTH EAST AUSTRALIA					
Eastern Gas Pipeline	Vic–NSW	Jemena	Expansion from 250 TJ/d to 268 TJ/d	41	2010
Victorian Transmission System (GasNet)	Vic	APA Group	Northern section expansion		2011
Moomba to Sydney Pipeline	NSW	APA Group	Young to Wagga lateral		2010
WESTERN AUSTRALIA					
Dampier to Bunbury Stage 5B expansion	WA	DUET Group 80%, Alcoa 20%	Expansion—additional 110 TJ/day	675	2010
UNDER CONSTRUCTION					
NORTH EAST AUSTRALIA					
South West Queensland Pipeline—stage 3	Qld	Epic Energy	Expansion—additional 199 TJ/d	760	2012
QSN Link—stage 3	Qld–SA and NSW	Epic Energy			
Queensland Curtis LNG (QCLNG) Pipeline	Qld	BG Group	540 km		Construction commenced in 2010
Roma to Brisbane	Qld	APA Group	10 per cent capacity expansion	50	2012
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	NSW	APA Group	Five year 20 per cent capacity expansion	100	2009–13
Victorian Transmission System (GasNet)	Vic	APA Group	Sunbury looping project		2012
ANNOUNCED					
NORTH EAST AUSTRALIA					
Queensland Hunter Pipeline (Wallumbilla to Newcastle)	Qld–NSW	Hunter Gas Pipeline	831 km	900	Construction commencing in 2012
Gladstone LNG (GLNG) Pipeline	Qld	Santos, Petronas, Total, Kogas	420 km		2015
Arrow Bowen Pipeline (Bowen Basin–Gladstone)	Qld	Arrow (Shell and PetroChina	600 km	1000	Construction commencing in 2012
Australian Pacific LNG (APLNG) Pipeline	Qld	Origin, Sinopec, ConocoPhillips	450 km		2014
Arrow Surat Pipeline	Qld	Arrow	450 km	550	Construction commencing in 2015–16
SOUTH EAST AUSTRALIA					
Narrabri to Wellington Pipeline	NSW	Eastern Star Gas	272 km	275	2009
Young to Wellington Pipeline	NSW	ERM Power	219 km	200	Construction commencing in 2012
Lions Way Pipeline (Casino to Ipswich)	NSW–Qld	Metgasco	145 km	120	Construction commencing in 2012
Coolah to Newcastle Pipeline	NSW	Eastern Star Gas	280 km		2009

TJ/d, terajoules per day.

Sources: EnergyQuest, *Energy Quarterly* (various issues); National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites, reports and media releases.

in 2010. The expansion involved 440 kilometres of pipeline looping (duplication). On completion, around 94 per cent of the pipeline had been looped.

3.8 Upstream competition

Investment over the past decade has developed an interconnected transmission pipeline system linking gas basins in southern and eastern Australia. 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 has opened the Surat–Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition.

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 southern and eastern Australia. The reporting covers gas flows on particular pipelines and gas flows from competing basins to end markets.

Figure 3.7 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.

> 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 3.7 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, the SEA Gas Pipeline now transports greater volumes of gas for that market. The Moomba to Adelaide Pipeline transports gas from Queensland's Surat–Bowen Basin via the QSN Link, and from South Australia's Cooper Basin. The SEA Gas Pipeline delivers gas 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.

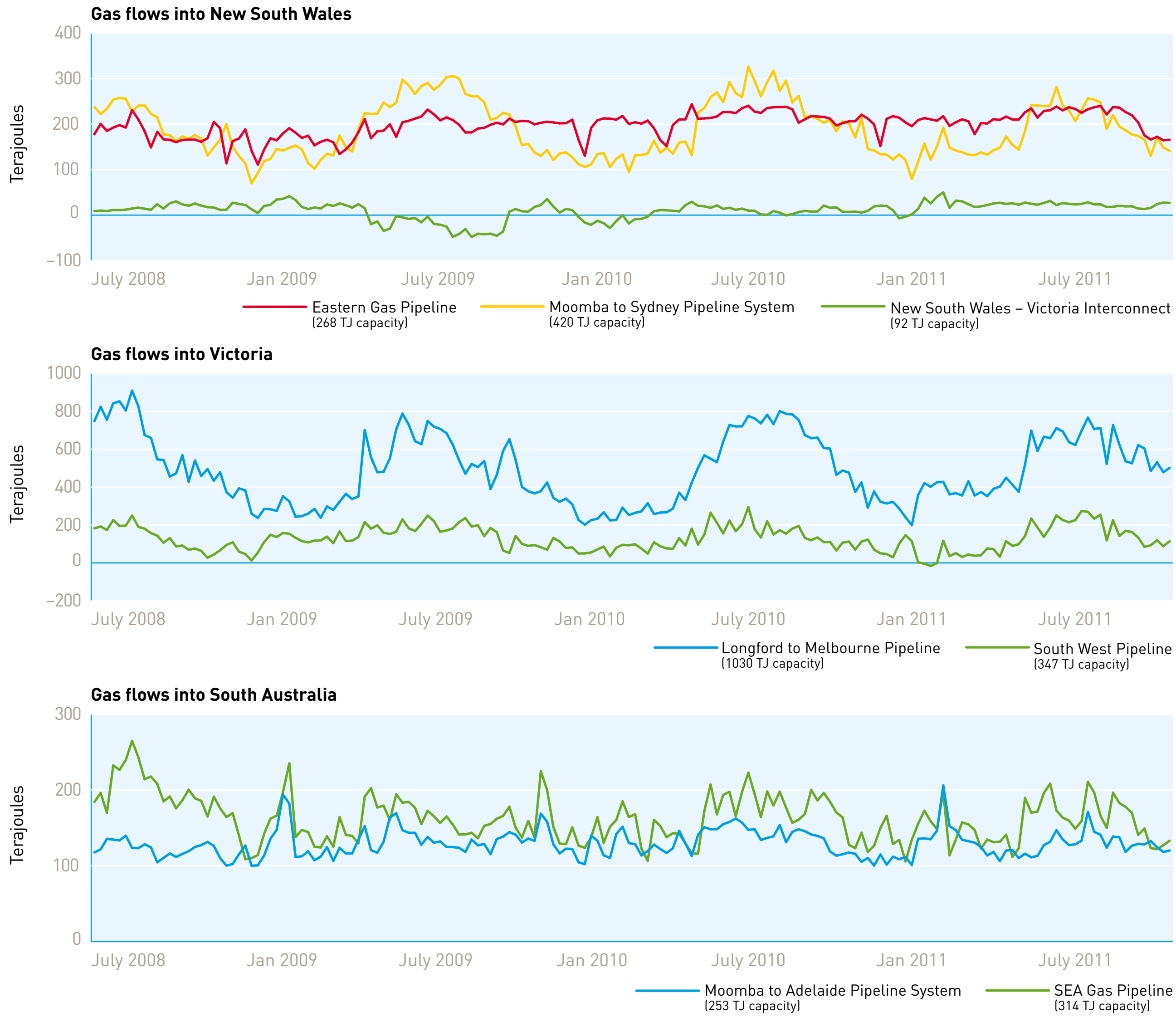
3.9 Gas storage

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 fired electricity generation, gas storage enhances security of energy supply by allowing for injections into the system 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, Western Australia and the Cooper Basin. In Victoria, the largest facility is the Iona gas plant, owned by TRUenergy, which has 22 PJ of storage capacity and can deliver 570 terajoules of gas per day. In Western Australia, a scheduled expansion of the Mondarra storage facility will increase storage capacity to 15 PJ, and will allow injection and withdrawals to be made on both the Dampier to Bunbury and Parmelia pipelines. Also, following its purchase of Mosaic Oil in 2010, AGL Energy is developing a CSG storage facility in Queensland.

Figure 3.7

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).

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 2010 AGL Energy announced it would develop a $300 million LNG storage facility in New South Wales by 2014 to ensure security of supply during peak periods and supply disruptions.

3.10 Gas distribution

A gas distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes lead off the high pressure mains to end customers.

Table 3.5 Gas distribution networks in southern and eastern Australia

NETWORK	CUSTOMER NUMBERS	LENGTH OF MAINS (KM)	OPENING CAPITAL BASE (2010 $ MILLION)[1]	INVESTMENT—CURRENT ACCESS ARRANGEMENT (2010 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND						
APT Allgas	84 400	2 900	413	125	1 Jul 2011–30 Jun 2016	APA Group
Envestra	84 710	2 560	309	136	1 Jul 2011–30 Jun 2016	Envestra (APA Group 33.1%, Cheung Kong Infrastructure 19.5%)
NEW SOUTH WALES AND ACT						
Jemena Gas Networks (NSW)	1 050 000	24 430	2 313	768	1 Jul 2010–30 Jun 2015	Jemena (Singapore Power International)
ActewAGL	112 000	4 160	278	88	1 Jul 2010–30 Jun 2015	ACTEW Corporation (ACT Government) 50%, Jemena (Singapore Power International) 50%
Wagga Wagga	23 800	680	60	20	1 Jul 2010–30 Jun 2015	Envestra (APA Group 33.1%, Cheung Kong Infrastructure 19.5%)
Central Ranges System	7 000	180	n/a	n/a	2006–19	APA Group
VICTORIA						
SP AusNet	570 000	9 400	1 078	372	1 Jan 2008–31 Dec 2012	SP AusNet (listed company; Singapore Power International 51%)
Multinet	646 600	10 010	1 011	265	1 Jan 2008–31 Dec 2012	DUET Group
Envestra	550 070	9 640	949	447	1 Jan 2008–31 Dec 2012	Envestra (APA Group 33.1%, Cheung Kong Infrastructure 19.5%)
SOUTH AUSTRALIA						
Envestra	401 300	7 890	991	478	1 Jul 2011–30 Jun 2016	Envestra (APA Group 33.1%, Cheung Kong Infrastructure 19.5%)
TASMANIA						
Tas Gas Networks	6 500	730	117[1]	Not regulated	Not regulated	Tas Gas (Brookfield Infrastructure)
TOTALS	**3 536 380**	**72 580**	**7 519**	**2 699**		

n/a, Not available.

1. For Tasmania, the opening capital base value is an estimated construction cost. For other networks, the opening capital base is the initial capital base, adjusted for additions and deletions, as reset at the beginning of the current access arrangement period. All data are converted to June 2010 dollars.
2. Investment data are forecasts for the current access arrangement period, adjusted to June 2010 dollars.

Sources: Access arrangements for covered pipelines; company websites.

Gas is now reticulated to most Australian capital cities, major regional areas and towns. This section focuses on distribution networks in southern and eastern Australia, over which the AER has regulatory responsibilities. Table 3.5 summarises the major networks; figure 3.8 illustrates their locations.

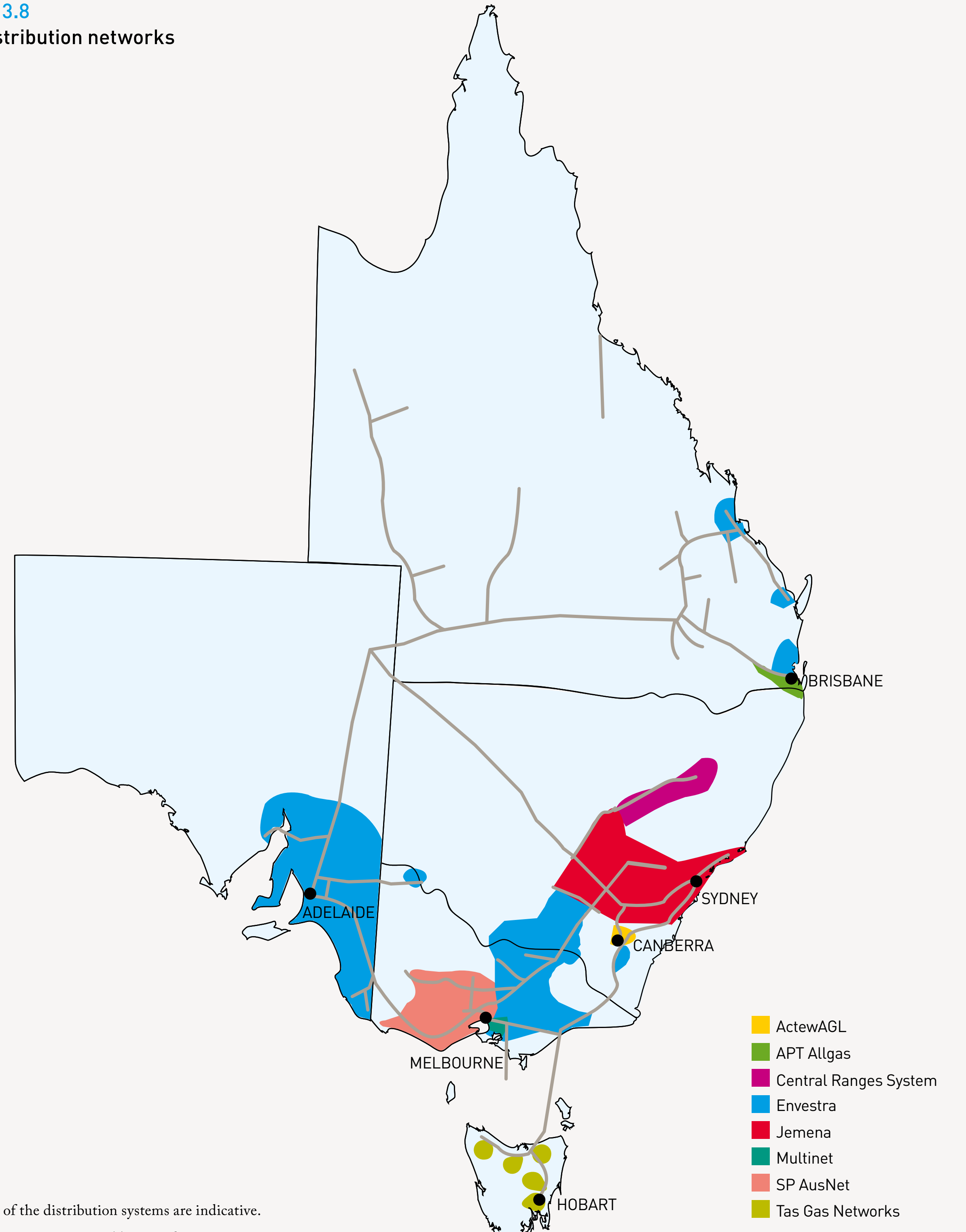
The total length of gas distribution networks in the southern and eastern jurisdictions was around 73 000 kilometres in 2011. The networks have a combined value of over $7 billion. Investment to augment and expand the networks is forecast at around $2.7 billion in the current access arrangement periods (typically five years).

3.10.1 Ownership of distribution networks

The major gas distribution networks in southern and eastern Australia are privately owned, with three principal players:

- *Jemena*, owned by *Singapore Power International*, owns the principal New South Wales gas distribution network (Jemena Gas Networks) and has a 50 per cent

Figure 3.8
Gas distribution networks



Notes:

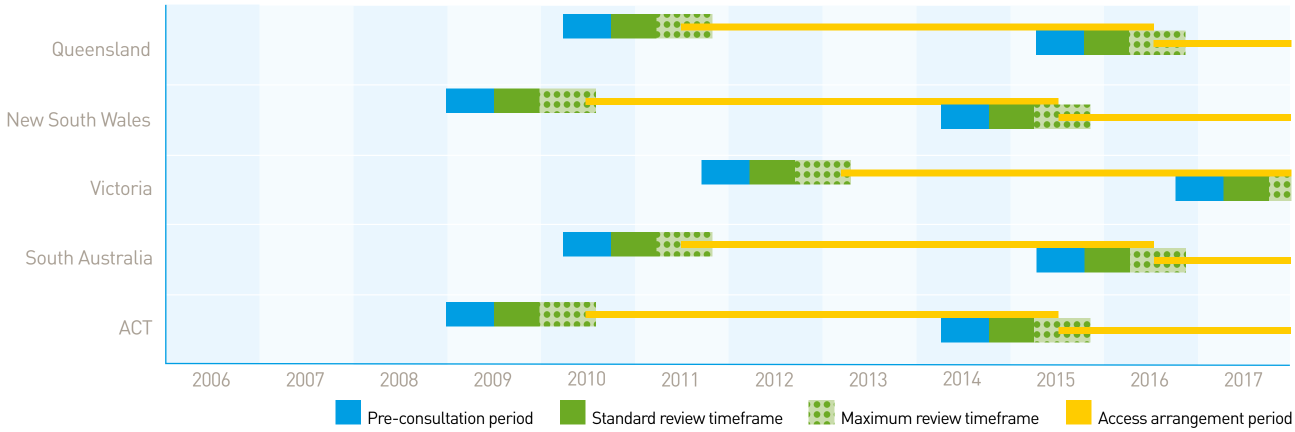
Locations of the distribution systems are indicative.

Some corporate names are abbreviated.

Source: AER.

Figure 3.9

Indicative timelines for AER determinations on gas distribution networks



Note: The timeframes are indicative. The standard review period begins when a network business submits an access arrangement proposal to the AER by a date specified in the previous access arrangement. The timeframes may vary if the AER grants a time extension for the proposal submission. An access arrangement period is typically five years, but a provider may apply for a different duration.

share of the ACT network (ActewAGL). Singapore Power International also has 51 per cent direct equity in a Victorian network (SP AusNet).

> *APA Group* owns the APT Allgas network in Queensland and the Central Ranges system in New South Wales, and has a 33 per cent stake in Envestra (up from 30.6 per cent in 2009).
> *Envestra*, a public company in which *APA Group* (33 per cent) and *Cheung Kong Infrastructure* (19 per cent) have shareholdings, owns networks in Victoria, South Australia, Queensland and the Northern Territory.

There has been a series of recent ownership changes related to former Babcock & Brown assets. In December 2010 *Brookfield Infrastructure* acquired a portfolio of these assets via a merger with Prime Infrastructure. Brookfield retained ownership of Tas Gas Networks, but in July 2011 sold a minority share in Victoria's Multinet distribution network to *DUET Group* (raising DUET's equity in the network from 80 to 100 per cent). Also in July 2011 Brookfield and DUET Group sold WA Gas Networks to *ATCO*.

The ownership links between gas distribution and other energy networks are significant. In particular, Jemena and APA Group own and/or operate gas transmission pipelines (section 3.7.1). In addition, Jemena, APA Group, Cheung Kong Infrastructure and DUET Group all have ownership interests—in some cases, substantial interests—in the electricity network sector (chapter 2).

3.10.2 Regulation of distribution networks

The AER regulates all major distribution networks in New South Wales, Victoria, Queensland, South Australia and the ACT, following a transfer of this role from state and territory agencies in July 2008. The Economic Regulation Authority undertakes this role in Western Australia. The recently constructed Tasmanian network is the only major unregulated network. In addition, a number of small regional networks are unregulated.[23]

The Gas Law and Rules set out the regulatory framework. Different forms of economic regulation apply to covered pipelines, based on criteria in the Gas Law. Most Australian distribution networks are subject to full regulation, which requires the service provider to submit an initial access arrangement to the regulator for approval, and revise it periodically (typically every five years).[24]

23 The unregulated networks include the South West Slopes and Temora extensions of the NSW Gas Network; the Dalby and Roma town systems in Queensland; the Alice Springs network in the Northern Territory; and the Mildura system in Victoria.

24 A distribution pipeline may be subject to light regulation in some circumstances, which means the service provider must publish the terms and conditions of access on its website. No distribution networks in Australia are covered by light regulation.

An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service likely to be sought by a significant part of the market, and a reference tariff for that service. The AER published an *Access arrangement guideline* (available on its website) that details the regulatory process. Separate guidelines address dispute resolution and compliance with obligations under the Gas Law.[25]

In summary, the regulatory process employs a building block approach to determine total network revenues and derive reference tariffs. The Gas Rules also allow for income adjustments from incentive mechanisms that reward efficient operating practices. In a dispute, an access seeker may request the regulator to arbitrate on and enforce the terms and conditions of the access arrangement.

Figure 3.9 shows indicative regulatory timeframes for the networks. In June 2011 the AER completed reviews of access arrangements for the South Australian and Queensland gas distribution networks.

The AER's decisions are subject to merits review by the Australian Competition Tribunal. Between September 2008 and October 2011, network businesses sought reviews of five AER determinations on gas distribution networks. Three reviews were continuing in October 2011. The two completed merits reviews increased allowable network revenues by around $190 million.

In September 2011 the AER submitted a Rule change proposal to the AEMC, which recommended changes in the approach to determining the weighted average cost of capital for gas pipelines. The proposal aimed to create a more consistent framework between the electricity and gas sectors for determining the cost of capital. The proposed changes involve a periodic industry-wide review of the cost of capital parameters (box 2.1, chapter 2).

3.10.3 Investment in distribution networks

The capital drivers for gas distribution networks are broadly similar to those for electricity distribution. The underlying drivers include rising connection numbers, the replacement of ageing networks, and the maintenance of capacity to meet customer demand. For example, a significant driver of Envestra's capital expenditure for its South Australian distribution network is the replacement of cast iron and unprotected steel mains, to address leaks from older sections of the pipeline.

Figure 3.10 illustrates investment forecasts by access arrangement periods (typically five years) for those networks over which the AER has conducted reviews—networks in Queensland, New South Wales, South Australia and the ACT; the first reviews of the Victorian networks will be completed in 2012.

> Investment in the reviewed networks is forecast to increase in real terms by 74 per cent over investment in the previous periods.
> Investment in current access arrangements is running, on average, at 36 per cent of the underlying opening capital base for the networks.
> Investment in Envestra's Queensland and South Australian distribution networks is forecast to rise by 72 per cent and 163 per cent respectively in the current access arrangement periods, compared with levels in previous periods. In contrast, forecast investment in APT Allgas's Queensland distribution network is roughly unchanged from the level in the previous period.

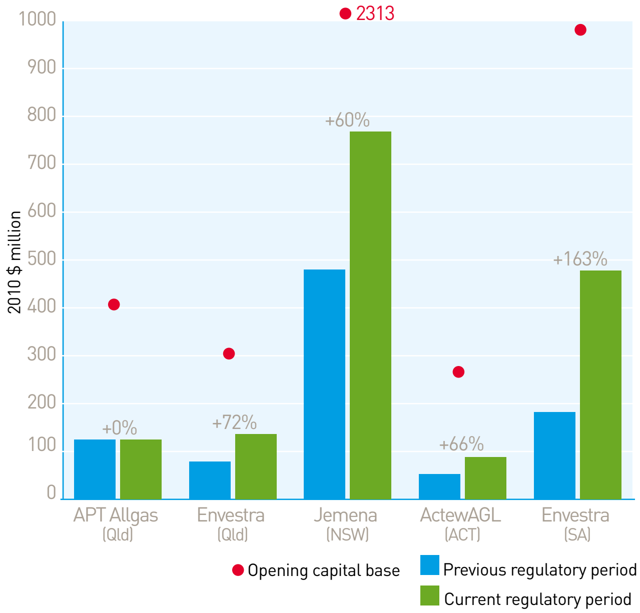
3.10.4 Operating expenditure

Operating expenditure refers to the operating, maintenance and other costs of a non-capital nature that service providers incur in providing distribution pipeline services. Figure 3.11 compares forecast operating expenditure in current access arrangement periods with levels in previous periods, for those networks over which the AER has reviewed access arrangements.

Real operating expenditure is forecast to increase in the current access arrangement periods, compared with previous periods, by 4 per cent (Envestra in South Australia) to 28 per cent (ActewAGL in the ACT).

25 AER, *Access arrangement guideline*, 2009; AER, *Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules*, 2008; AER, *Annual compliance guideline*, 2010.

Figure 3.10
Gas distribution network investment



Notes:

Forecast capital expenditure in the current regulatory period (typically five years), compared with levels in previous periods. See table 3.5 for the timing of current regulatory periods.

Opening capital bases are at the beginning of the current access arrangement period.

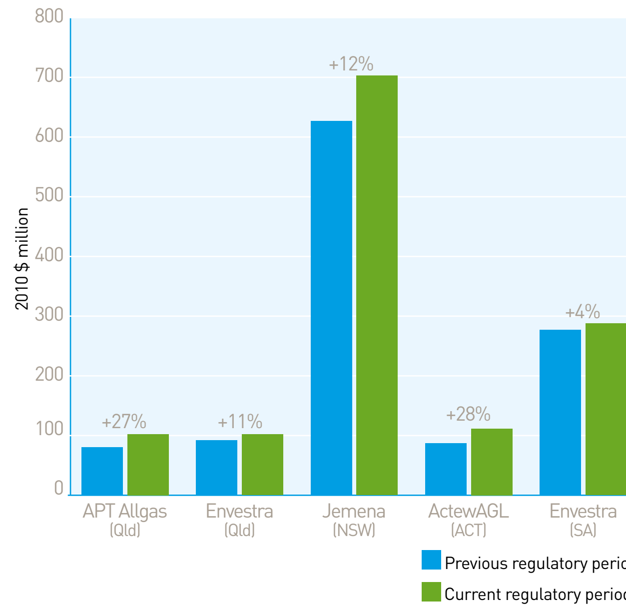
All values are converted to June 2010 dollars.

Sources: Access arrangements approved by the AER.

3.10.5 Retail impacts

Rising capital and operating expenditure, as well as other cost drivers (including higher financing costs and the rising cost of unaccounted for gas), are expected to increase distribution network charges in current access arrangement periods beyond levels in previous periods. Figure 3.12 shows the effects of higher network charges on gas retail prices (in nominal terms). The decisions resulted in initial retail price rises of 4–8 per cent and further increases of 4.1–5.5 per cent for each subsequent year of the access arrangement period. Gas distribution charges typically make up about 40–60 per cent of the retail price of gas (section 4.3).

Figure 3.11
Gas distribution operating expenditure



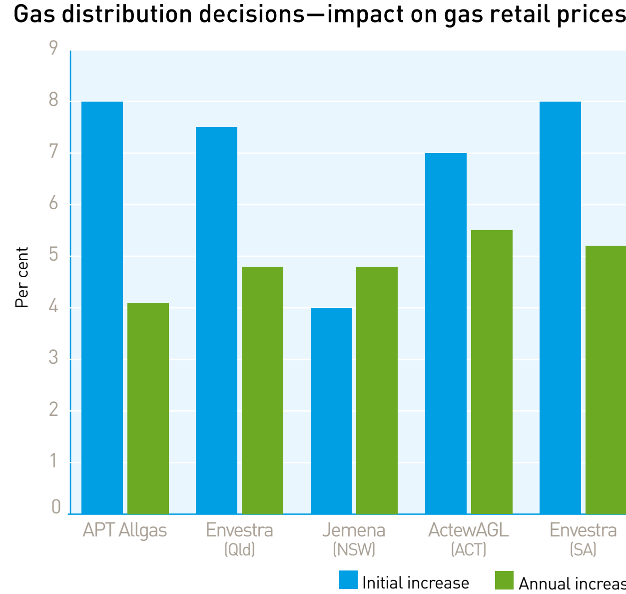
Notes:

Forecast operating expenditure in the current access arrangement period (typically five years), compared with levels in previous periods. See table 3.5 for the timing of current regulatory periods.

All values are converted to June 2010 dollars.

Sources: Access arrangements approved by the AER.

Figure 3.12
Gas distribution decisions—impact on gas retail prices



Note: Price impact estimate is for a typical residential customer.

Sources: Access arrangements approved by the AER.