3 UPSTREAM GAS MARKETS

Australia produced 1400 petajoules (PJ) of gas in 2013–14 for domestic use.[1] While gas is widely used for industrial manufacturing, around 31 per cent of Australian gas consumption is for electricity generation.[2] 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.

Australia also produces liquefied natural gas (LNG) for export, accounting for 43 per cent of Australia's gas production. This proportion is about to rise significantly, with the commencement of LNG exports from Queensland in 2014–15.

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;[3] 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 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,[4] 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).

3.1 Gas reserves and production

In February 2014 Australia's proved and probable (2P) gas reserves stood at around 139 000 PJ, comprising 96 000 PJ of conventional gas and 43 000 PJ of CSG (table 3.1). Australia produced 2450 PJ of gas in 2013–14, of which 57 per cent was for the domestic market. The balance—all sourced from offshore basins in Western Australia and the Timor Sea—was exported as LNG. This ratio will increase, with the development of new LNG projects in Queensland and Western Australia (section 3.1.2).

3.1.1 Geographic distribution and major players

Eastern Australia contains around 36 per cent of Australia's gas reserves, of which 87 per cent are CSG reserves, mostly located in Queensland's Surat–Bowen Basin (figures 3.2 and 3.8). In New South Wales (NSW), limited commercial production of CSG occurs in the Sydney and Gunnedah basins.

The Surat-Bowen Basin supplies 36 per cent of the eastern gas market. Over 98 per cent of gas produced in the basin is CSG. Ownership is relatively diverse, with BG Group, Origin Energy and ConocoPhillips being the largest producers. Other players include Sinopec, Santos, Shell, PetroChina, Petronas, Total and AGL Energy. The same businesses also own the majority of reserves in the basin. Many of these entities entered the Queensland market to develop major LNG projects (section 3.1.2).

The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and provide gas to NSW, South Australia and Tasmania. The Gippsland Basin is the most significant of the three, supplying 34 per cent of the eastern market. A joint venture between ExxonMobil and BHP Billiton accounts for 96 per cent of the basin's production. Production in the Otway Basin (15 per cent of eastern production) has risen significantly since 2004. Origin Energy, BHP Billiton and Santos are the main players. The principal

1 Bureau of Resources and Energy Economics (BREE), unpublished, 2014. Due to accounting differences, BREE production data is typically higher than the EnergyQuest data published in previous editions of this report.

2 BREE, *Gas market report*, October 2013, p. 26.

3 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.

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

Figure 3.1
Domestic gas supply chain

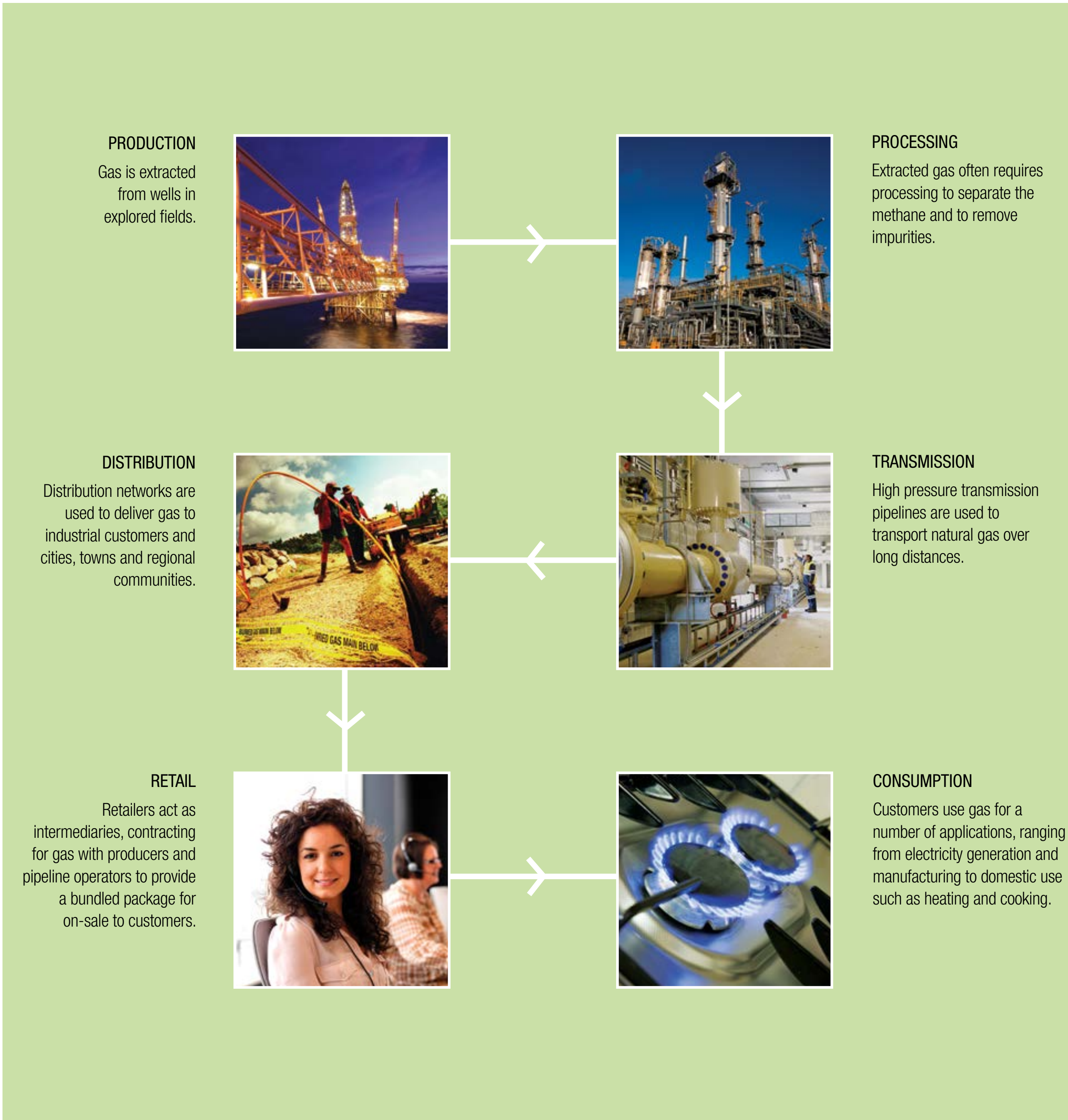


Image sources: Origin Energy, Woodside, Jemena.

Table 3.1 **Gas reserves and production, 2014**

GAS BASIN	GAS PRODUCTION[1,2] (YEAR TO JUNE 2014) PETAJOULES	SHARE OF AUSTRALIAN PRODUCTION (%)	CHANGE FROM PREVIOUS YEAR (%)	PROVED AND PROBABLE RESERVES[3] (FEBRUARY 2014) PETAJOULES	SHARE OF AUSTRALIAN RESERVES (%)
EASTERN AUSTRALIA					
Cooper (South Australia – Queensland)	104	4.3	–2.9	1 802	1.3
Gippsland (Victoria)	279	11.4	–9.4	3 568	2.6
Otway (Victoria)	119	4.9	–1.6	750	0.5
Bass (Victoria)	17	0.7	47.8	250	0.2
Surat–Bowen (Queensland)					
conventional gas	5	0.2	9.8	131	0.1
coal seam gas	290	11.8	5.3	41 156	29.6
New South Wales basins					
conventional gas	0	0.0	0.0	17	0.0
coal seam gas	5	0.2	–14.4	2 266	1.6
EASTERN AUSTRALIA TOTALS	**820**	**33.5**		**49 940**	**36.0**
WESTERN AUSTRALIA					
Browse	0	0.0	0.0	17 384	12.5
Carnarvon	1 599	65.2	3.1	70 386	50.7
Perth	6	0.2	–22.4	54	0.0
NORTHERN TERRITORY					
Amadeus	<1	0.0	–4.6	178	0.1
Bonaparte (Blacktip)	26	1.1	0.2	870	0.6
AUSTRALIAN TOTALS	**2 451**			**138 812**	
DOMESTIC CONSUMPTION	1 395				
LIQUEFIED NATURAL GAS (EXPORTS)	1 055				
TIMOR SEA					
Joint Petroleum Development Area[4]	260			114	

1 Production is conventional gas, other than in Surat–Bowen and NSW basins.

2 Includes gas consumed on site in the production process.

3 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.

4 Gas reserves in the Joint Petroleum Development Area are jointly managed by Australia and Timor-Leste. Revenue from production is split between Timor-Leste and Australia on a 90:10 basis. Production data for 2013–14 is preliminary, based on ABS trade statistics.

Note: Due to accounting differences, BREE production data is typically higher than the EnergyQuest data published in previous editions of this report.

Sources: Gas production: Bureau of Resources and Energy Economics (BREE), unpublished; gas reserves: EnergyQuest, *EnergyQuarterly,* February 2014.

producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration.

In central Australia, a joint venture led by Santos dominates production in the Cooper Basin, which supplies 13 per cent of the eastern market. The other participants are Beach Petroleum and Origin Energy. After several years of decline, Cooper Basin reserves in central Australia rose over the past three years, with new activity focused on the development of shale gas. Santos commenced shale gas production in 2012.

Western Australia's offshore Carnarvon Basin holds half of Australia's 2P gas reserves. It is Australia's largest producing basin, supplying both the domestic market and LNG exports. Several major companies have equity in the basin. The businesses participate in joint ventures, typically with overlapping ownership interests. Chevron, Shell and ExxonMobil have the largest reserves, given their equity

Figure 3.2
Australian gas basins and major transmission pipelines

Pipeline	No.
Moomba to Sydney Pipeline	1
Eastern Gas Pipeline (Longford to Horsley Park)	2
NSW–Victoria Interconnect	3
Victorian Transmission System	4
Tasmanian Gas Pipeline	5
SEA Gas Pipeline	6
Moomba to Adelaide Pipeline	7
QSN Link	8
South West Queensland Pipeline (Ballera to Wallumbilla)	9
Roma to Brisbane Pipeline	10
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	11
Amadeus Basin to Darwin Pipeline	12
Bonaparte Pipeline	13
Dampier to Bunbury Natural Gas Pipeline	14
Goldfields Gas Pipeline	15

Source: AER.

Pluto LNG Plant (Woodside)

in the Gorgon project. Apache Energy, Woodside and Santos are the largest producers for Western Australia's domestic market.

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, which produces LNG for export and gas for consumption in the Northern Territory (via the Bonaparte Pipeline). The basin displaced the Amadeus Basin as the main source of gas for the Northern Territory.

3.1.2 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.

Global gas demand slowed during 2013–14, translating into softer prices. International LNG spot prices in September 2014 reached their lowest level since April 2011.[5] Despite this softening, the value of Australia's LNG exports rose in 2013–14 by 15 per cent to $16.5 billion, becoming Australia's third largest export after iron ore and coal.[6]

Australia's LNG export sector is about to be transformed, with three major LNG projects in Queensland nearing completion. Projections of rising international energy prices, together with rapidly expanding reserves of CSG in the Surat–Bowen Basin, spurred the development of the projects. The three projects, the world's first to convert CSG to LNG, include processing facilities at the port of Gladstone and transmission pipelines to ship gas from the Surat–Bowen Basin:

- The $20 billion Queensland Curtis LNG (QCLNG) project, owned by BG Group is scheduled to begin LNG exports in late 2014. The project will initially produce 8.5 million tonnes of LNG per year, with potential capacity of 12 million tonnes.
- The $24.7 billion Australia Pacific LNG project (Origin Energy, ConocoPhillips and Sinopec) is expected to begin LNG exports in 2015.
- 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.

In 2014 the LNG project developers continued to build and test wells, processing facilities, liquefaction plants and transmission pipelines from CSG fields to the Gladstone shipping terminal. The developers also interconnected their pipelines to enable physical gas flows between projects.

Some new production facilities became fully operational in 2014, including Australia Pacific LNG's Condabri Central production facility and QCLNG's Ruby Jo facility. Other facilities at Bellevue (QCLNG), Condabri, Reedy Creek and Orana (Australia Pacific LNG) were scheduled to commence production late in 2014.

Major LNG players are also expanding capacity in Western Australia and northern Australia:

- Chevron's Gorgon project (Carnarvon Basin) is nearing completion. It is scheduled to deliver its first shipment of LNG by the middle of 2015 and expected to produce around 15.6 million tonnes of LNG per year. The project partners signed long term sales agreements with international buyers. 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 the $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, with a final investment decision targeted for 2015.

3.1.3 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. Gas storage enhances the security of energy supply by allowing for system injections at short notice to better manage peak demand and emergencies. It also allows producers to meet contract

5 EnergyQuest, *EnergyQuarterly August 2014*, Media release, 29 August 2014.

6 EnergyQuest, *EnergyQuarterly August 2014*, Media release, 29 August 2014.

requirements if production is unexpectedly curtailed. And it provides retailers with a hedging mechanism if gas demand varies significantly from forecast.

The importance of gas storage in managing supply and demand fluctuations will rise as east coast dynamics evolve to integrate an LNG export market.[7] 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 (TJ) of gas per day. In Queensland, AGL Energy stores gas underground at the depleted Silver Springs reservoir in central Queensland (35 PJ). This facility supports the development of the Curtis LNG project and allows AGL Energy to manage its gas supply during seasonal variations in summer and winter. The Cooper Basin Joint Venture owns 85 PJ of underground storage at Moomba and another 14 PJ at Ballera.[8]

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 NSW, AGL Energy is constructing a $300 million LNG storage facility (1.5 PJ) 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 TJ per day.

3.2 Domestic gas market

In the domestic market, producers sell gas to major industrial, mining and power generation customers, and to energy retailers that onsell the gas 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 effectively capped gas prices.

While gas prices were historically struck under confidential, long term contracts, the industry has shifted towards shorter term contracts, the inclusion of review provisions, and the use of spot markets:

- A short term trading market for gas was launched in Sydney and Adelaide in 2010, with Brisbane following in 2011 (section 3.2.1). The market provides a means for participants to manage contractual imbalances, and is supported by a National Gas Bulletin Board (section 3.2.3).
- Victoria established a wholesale spot market in 1999 for gas sales, to manage system imbalances and pipeline constraints (section 3.2.2).
- As part of the Australian Government's energy market reforms, a gas supply hub was launched at Wallumbilla, Queensland in March 2014. The hub, which links gas markets across eastern Australia, aims to relieve bottlenecks by facilitating short term gas trades (section 3.2.4).

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to 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 draws on this information to publish weekly reports on gas market activity in eastern Australia.

3.2.1 Short term trading market

A short term trading market—a wholesale spot market for gas—has been implemented at selected hubs (junctions) linking transmission pipelines and distribution systems in eastern Australia. The Australian Energy Market Operator (AEMO) operates the market, which was designed to enhance gas market transparency and competition by setting prices based on supply and demand conditions.[9]

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 3.2.2).

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

7 Australian Government (Department of Industry), *Energy green paper*, September 2014.

8 BREE, *Eastern Australian domestic gas market study*, January 2014.

9 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

The AER in 2013 investigated the high costs of MOS services in the Sydney and Adelaide hubs of the short term trading market, responding to concerns that these costs may deter new entry. It found a tendency for excessive MOS payments on high demand days. In some instances, the volume of MOS gas significantly exceeded the magnitude of the underlying physical imbalance in gas volumes. The issue peaked on 25 June 2013, when MOS payments in Adelaide exceeded $250 000.

The AER found nomination issues in Sydney and design issues in Australian Gas Networks' Adelaide distribution network periodically raised MOS volumes above necessary levels. It met with industry participants in both markets to resolve the issues. The nomination issue in Sydney was subsequently resolved.

In Adelaide, Australian Gas Networks investigated solutions to the network design issue, which had caused parts of its network to be better served by gas from the Moomba to Adelaide Pipeline than from the SEA Gas pipeline. In July 2014 it opened the Elizabeth valve that had previously isolated part of the network from gas sourced from SEA Gas. Following this action, MOS payments were significantly lower than in the corresponding period in 2013.

Some excessive MOS payments still occur, likely reflecting the timing of nominations and renominations by participants on the SEA Gas pipeline. As an example, a MOS payment of almost $200 000 on 20 August 2014 occurred when renominations to increase flows on SEA Gas were made late in the day to apply overnight. The AER is closely monitoring such activity to ensure participants do not do anything for the purpose of creating a pipeline deviation for which MOS may be required (rule 399(6)) of the National Gas Rules). Further, the eligibility requirements for providing MOS services were broadened from June 2014 to promote competition. One change allows participants to submit MOS offers on a monthly rather than quarterly basis.

On 19 October 2014 MOS payments on the Moomba to Adelaide Pipeline were $67 800, despite only 4.4 TJ of MOS being required. In part, the high payment reflected some participants' decision to offer less MOS in October than in other months. MOS offers and payments returned to normal levels in the following weeks.

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 acted this year to reduce excessive MOS payments in the market (box 3.1).

Section 3.4 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.

3.2.2 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 transmission constraints.[10]

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 3.4 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.

3.2.3 National Gas Bulletin Board

The National Gas Bulletin Board, launched in 2008, is a web based platform (www.gasbb.com.au) that promotes trade in gas. It covers major gas production plants, storage facilities, demand centres and transmission pipelines in eastern Australia. The bulletin board provides transparent, real-time information on 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.

In March 2014 the Council of Australian Governments (CoAG) Energy Council asked AEMO to overhaul the bulletin board's functionality to better serve the needs of Australia's fast evolving gas markets. AEMO is developing refinements in consultation with stakeholders, including gas pipeline owners and operators, facility operators, major shippers, retailers and gas users. In November 2014 AEMO was progressing the site's redevelopment and testing.

In 2014 a number of new production facilities associated with LNG projects became operational and began reporting on the bulletin board. The AER engaged with industry, including LNG producers, to ensure they provide accurate capacity outlooks and production data to AEMO for the bulletin board.

3.2.4 Gas supply hub at Wallumbilla, Queensland

In consultation with industry, AEMO launched a new gas supply hub at Wallumbilla, Queensland in March 2014. Energy ministers commissioned the project to support south east Queensland's rapidly expanding gas industry. As a pipeline interconnection point, Wallumbilla links gas markets in Queensland, South Australia, NSW and Victoria.

The hub uses a brokerage model to match and clear trades between gas buyers and sellers at Wallumbilla's three pipeline delivery points. While the market initially operates only at Wallumbilla, it may later be introduced at other locations. The flexible design can be adapted to the circumstances of any location. The CoAG Energy Council will review the hub model in 2015 and consider refinements based on operational experience.

As with other spot markets, the AER monitors and enforces compliance with the market conduct rules, and reports on market activity. Section 3.5 further discusses the hub, including an overview of activity in 2014.

3.3 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).

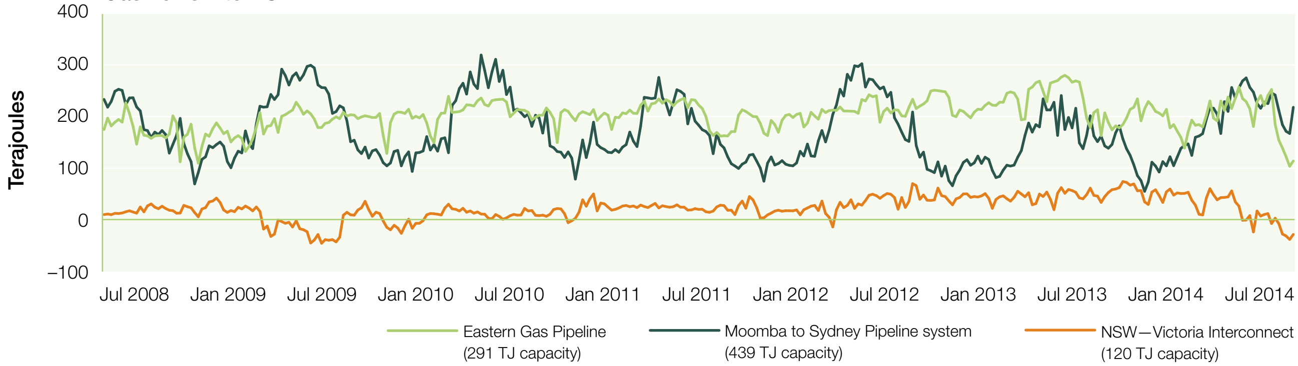
The AER draws on the bulletin board to report on gas flows in eastern Australia. Figure 3.3 illustrates trends in gas delivery from competing basins into NSW, Victoria and South Australia since the bulletin board opened in July 2008:

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

Figure 3.3

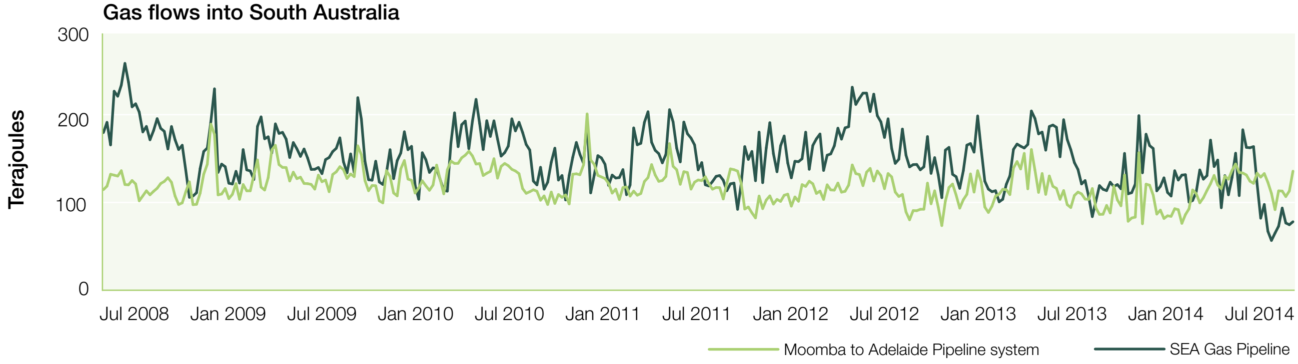
Gas flows in eastern Australia

Gas flows into NSW



Gas flows into Victoria

Gas flows into South Australia



Note: Negative flows on the NSW–Victoria Interconnect represent flows out of NSW into Victoria.

Sources: AER; National Gas Bulletin Board (www.gasbb.com.au).

- NSW sources gas from basins in Queensland and central Australia (via the Moomba to Sydney Pipeline), and from Victoria (via the Eastern Gas Pipeline and the NSW–Victoria Interconnect). Gas flows on the Moomba to Sydney Pipeline fluctuate seasonally, while flows on the Eastern Gas Pipeline are steadier. A downturn in gas flows from Victoria in 2014 reflects a weakening in gas demand in NSW. Overall, gas flows into NSW were 30 per cent lower in September–October 2014 than in the corresponding period in 2013. But gas flows on the Moomba to Sydney Pipeline were steadier, due to very low spot gas prices in Queensland.
- 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 3.3 illustrates the seasonal nature of Victorian gas demand, with significant winter peaks.
- South Australia sources gas from central Australia and Queensland via the Moomba to Adelaide Pipeline, and from Victoria via the SEA Gas Pipeline.

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.

3.4 East coast gas market activity

The development of LNG export projects in Queensland is exerting significant pressure on the domestic gas market. Gas production in eastern Australia is forecast to treble over the next two decades to 2033 to meet international LNG demand,[11] with the first exports scheduled for 2014–15.

While Queensland's LNG proponents each have dedicated gas reserves, they are also sourcing reserves that might otherwise have been available to the domestic market. This development has made it difficult for domestic customers to buy gas under medium to long term contracts.[12] Adding to this difficulty, a large number of domestic gas supply contracts will soon expire. In NSW, existing contracts will meet less than 15 per cent of that state's gas demand by 2018.[13]

11 AEMO, *Gas statement of opportunities*, May 2014.

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

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

The effect of these tight market conditions was apparent in 2013, with prices in new gas contracts reportedly linked to international oil prices or LNG netback.[14] Modelling by Sinclair Knight Merz (SKM) in 2013 forecast wholesale gas prices would rise from around $4 per gigajoule to $9 per gigajoule by 2016, with reasonable price alignment across cities.[15] The Grattan Institute and Deloitte Access Economics confirmed this order of price increases were being factored into new contracts in 2014.[16] SKM projected prices would stabilise at around $7.50–$8 per gigajoule by 2019. The Australian Government's energy green paper noted in September 2014 that sellers appear to have access to more market information than buyers, raising policy concerns.[17]

Consistent with developments in the contract market, spot gas prices rose strongly in 2012–13, averaging over $5 per gigajoule in Sydney, Adelaide and Brisbane (figure 3.4 and table 3.2). In particular, Brisbane prices diverged from other hubs, with weekly averages as high as $10 per gigajoule in January 2013. In part, the rises reflected a significant tightening of supply as producers reserved gas for Queensland's LNG projects. The rises also reflected the introduction of carbon pricing on 1 July 2012, which improved the cost competitiveness of gas powered electricity generation and triggered a withdrawal of coal fired generation capacity from the electricity market.

Average daily spot prices for gas in all markets were significantly lower in 2013–14 than in the previous year. Average prices fell by 23 per cent in Brisbane and Sydney, 15 per cent in Adelaide and 13 per cent in Melbourne. They ranged from $4.03 per gigajoule (Sydney) to $4.55 per gigajoule (Brisbane).

Spot prices settled around $4 per gigajoule for most of 2013–14 in all hubs except Brisbane, where prices fell from $5–6 per gigajoule towards $2 per gigajoule over the year. Winter prices were lower in all hubs in 2014 than in 2013, averaging just below $4 per gigajoule in Sydney, Melbourne and Adelaide (figure 3.5). The abolition of carbon pricing, which took effect on 1 July 2014, reduced the cost competitiveness of gas powered generation, contributing to weaker gas demand.

The divergence of Queensland prices from those in southern markets during 2014 coincided with rising gas production in south east Queensland (figure 3.6). New production

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

15 SKM, *Gas market modelling*, Gas Market Study Task Force, 2013.

16 Grattan Institute, *Gas at the crossroads*, Tony Wood, October 2014.

17 Australian Government (Department of Industry), *Energy green paper*, September 2014.

Figure 3.4

Spot gas prices — weekly averages

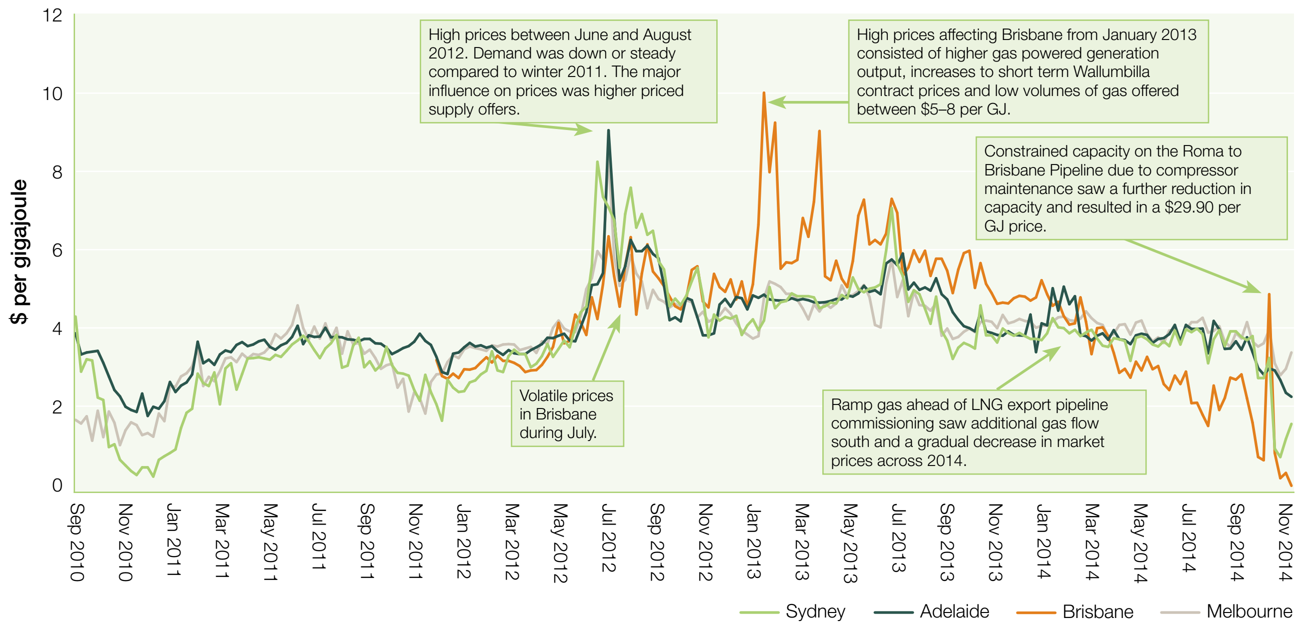
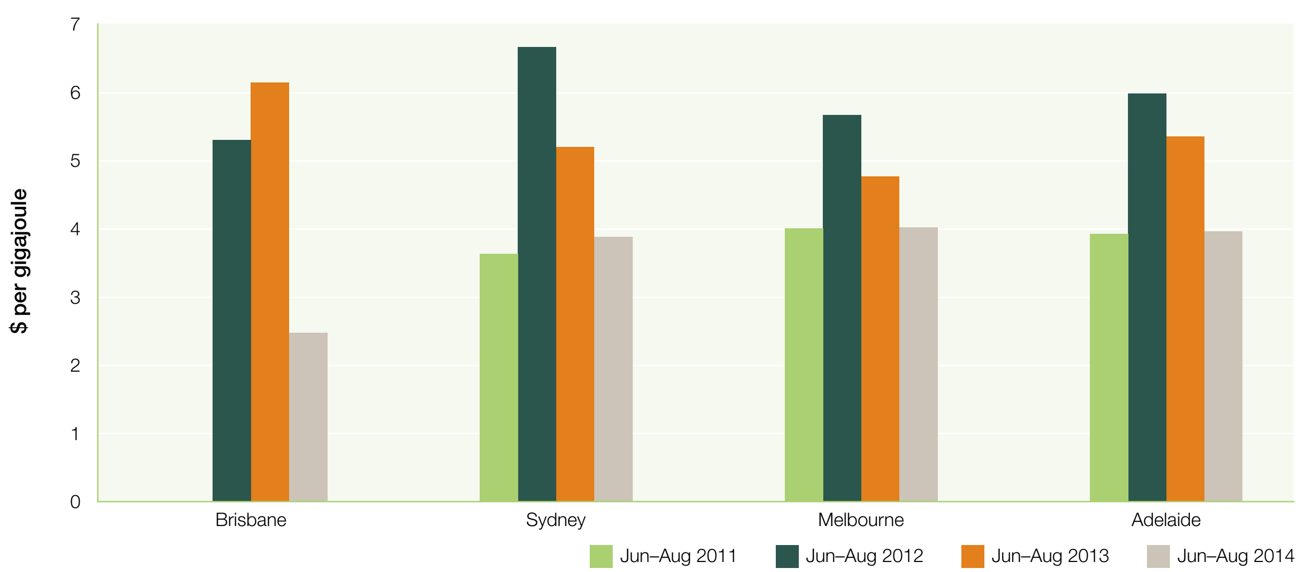


Figure 3.5

Spot gas prices — winter



Notes (table 3.2 and figures 3.4 and 3.5): Volume weighted ex ante prices derived from demand forecasts. 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. The Sydney data exclude the 1 November 2010 price of $150 per gigajoule, which data errors caused.

Sources (table 3.2 and figures 3.4 and 3.5): AER estimates (Melbourne); AEMO (other cities).

Table 3.2 **Average daily spot gas prices ($ per gigajoule)**

	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
2013–14	4.55	4.03	4.24	4.31
2012–13	5.92	5.20	4.86	5.09
2011–12	3.51	3.45	3.65	3.79
2010–11		2.37	2.75	3.17

facilities at Condabri and Ruby Jo became fully operational in preparation for LNG export, and other facilities were expected to commence production late in the year. LNG proponents sold significant quantities of ramp-up gas from these facilities into the Brisbane hub of the short term trading market and into the gas supply hub at Wallumbilla.

These increased gas flows caused Brisbane spot prices to collapse during 2014. October prices were mostly below $1 per gigajoule and fell close to zero on some days. Prices also trended lower in the gas supply hub at Wallumbilla (section 3.5). Despite the large volumes of ramp-up gas, pipeline constraints occasionally affected the market. Brisbane prices spiked briefly in early October 2014, for example, when planned outages and capacity constraints on the Roma to Brisbane Pipeline temporarily restricted capacity to transport gas.

Ramp-up gas also flowed into the southern states, reflected in rising flows on the QSN link (Ballera to Moomba) connecting Queensland with NSW and South Australia (figure 3.7). In September and October 2014 gas flows from Queensland along the QSN Link to South Australia and NSW more than doubled flows in the corresponding period in 2013. The rise in volumes caused Sydney prices to fall below $1 per gigajoule in October 2014 (figure 3.4). Additionally, these flows reduced NSW's usual reliance on Victorian gas, causing a reversal in gas flows between the two states along the NSW–Victoria Interconnect; that is, gas flowed south from NSW into Victoria (figure 3.7).

The collapse in gas prices flowed through to electricity markets in 2014. Cheaper gas stimulated a rise in gas powered generation and reduced daily spot electricity prices in Queensland to as low as $11 per megawatt hour in October 2014 (figure 7 in 'Market overview').

3.4.1 East coast supply–demand balance

Ramp-up gas will continue to be sold into domestic spot markets in the lead-up to commissioning each of Queensland's six committed LNG trains. The timing of commissioning each train is uncertain, although each of the three LNG projects expects to commission at least one train by mid-2015.

Market conditions will tighten once all LNG facilities are exporting at full capacity, with AEMO forecasting possible domestic supply shortfalls in the absence of new infrastructure developments.[18] But while international demand for east coast gas will rise exponentially, a countervailing influence is weaker projections on gas powered electricity generation, which accounts for 31 per cent of domestic gas demand.[19] Subdued electricity demand, the continued rise in renewable generation, the abolition of carbon pricing, and the cessation of the Queensland Gas Scheme (which mandated a minimum rate of gas powered generation) have stalled growth in gas powered generation. As an example, Stanwell took its Swanbank E generator offline in December 2014 for up to three years, reducing domestic gas demand over that period.

Accounting for these factors, AEMO in 2014 scaled back earlier projections on gas supply shortfalls in eastern Australia.[20] But various contingencies affect the forecasts, including the timing of commissioning each LNG train, changing forecasts of electricity demand growth (and the proportion of forecast demand expected to be sourced from gas powered generation), the effects of government climate change policies on gas demand, and the availability of gas storage facilities. In this volatile environment, industry participants are considering supply alternatives to avoid possible shortfalls:

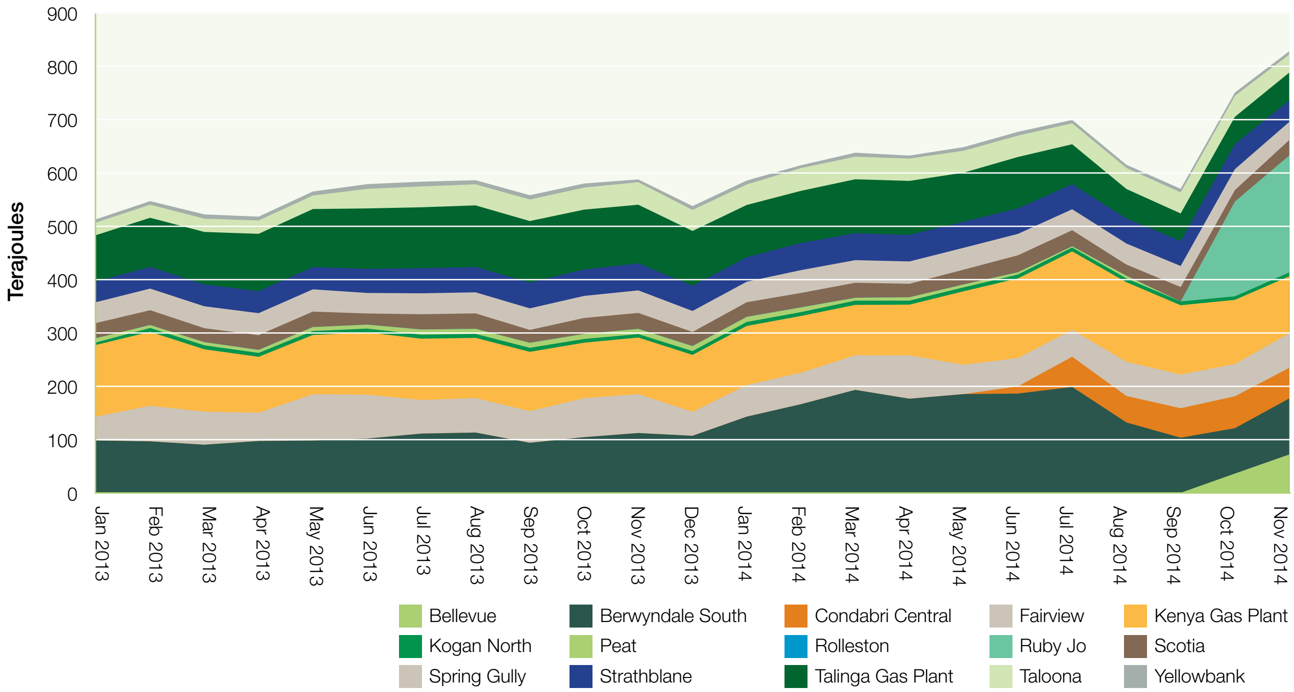
18 AEMO, *Gas statement of opportunities update,* May 2014.

19 BREE, *Gas market report*, October 2013, p. 26.

20 AEMO, *Gas statement of opportunities update,* May 2014.

Figure 3.6

Gas production around Roma, Queensland

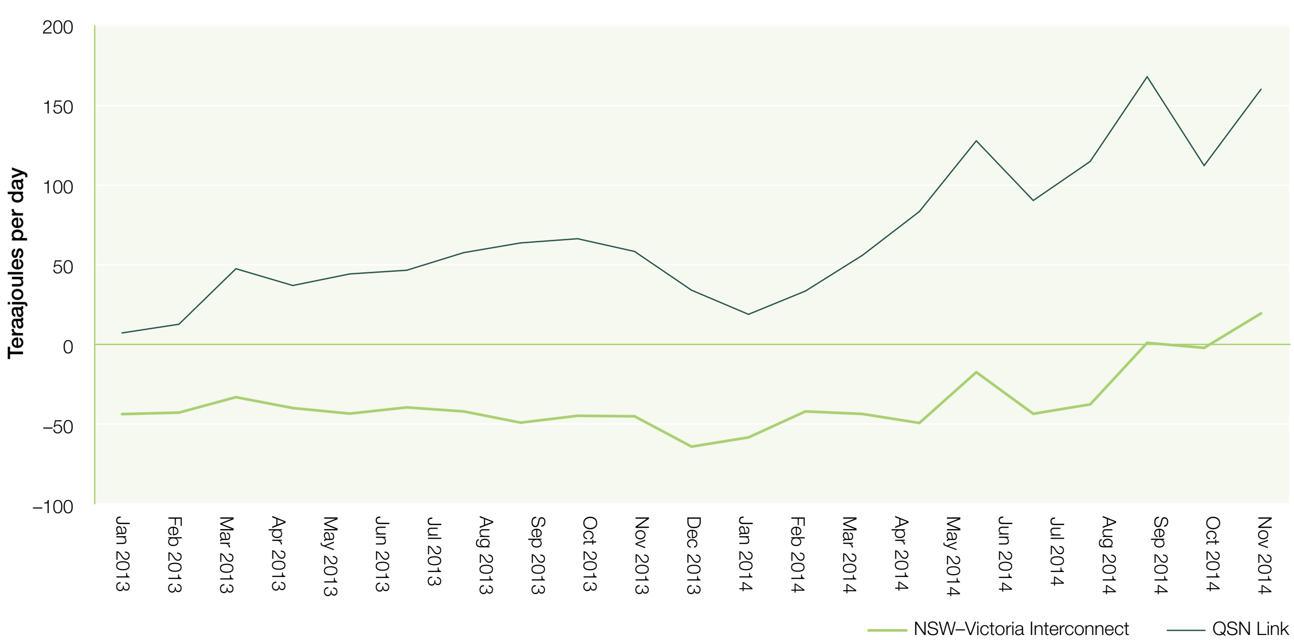


Note: The Roma region covers the Surat–Bowen Basin from which gas is sourced, processed and supplied to the Queensland Gas Pipeline, Roma to Brisbane Pipeline and South West Queensland Pipeline.

Sources: AER; National Gas Bulletin Board (www.gasbb.com.au).

Figure 3.7

Gas flows on the QSN Link and NSW–Victoria Interconnect



Sources: AER; National Gas Bulletin Board (www.gasbb.com.au).

- Pipeline owners have expanded or are expanding capacity on several transmission pipelines, including the NSW—Victoria Interconnect (due for completion in 2015); APA Group's 2013–14 expansion of the Victorian Transmission System to facilitate increased northbound gas exports from Victoria; augmentations of the South West Queensland and Queensland Gas pipelines (scheduled for completion in 2014); and storage capacity on the Tasmanian Gas Pipeline (progressively available from winter 2014). Jemena was considering a capacity expansion of the Eastern Gas Pipeline to boost capacity into NSW, which could be completed by the end of 2015. Additionally, the NSW and Northern Territory governments in November 2014 signed a Memorandum of Understanding to develop a pipeline connecting the Northern Territory with eastern gas markets.
- AGL Energy and Santos are seeking to develop CSG resources in the Gloucester and Narrabri basins in NSW. But community concerns about health and environmental impacts have delayed the development of projects in the state. The NSW Government in March 2014 applied a ban on CSG exploration licenses, which it later extended for 12 months. Concerns about environmental impacts also led the Victorian Government to place a moratorium on CSG extraction and fracking, which it later lengthened to July 2015 and extended to cover all onshore gas exploration.[21]

  The NSW Government in November 2014 launched a new strategic framework to determine appropriate areas to develop and extract gas, accounting for economic benefits and evidence of effects on the environment and communities. Pending licence applications under previous arrangements were to be extinguished. Once the new framework is in place in July 2015, the NSW Environment Protection Authority will be the lead regulator for gas exploration and production. It will be responsible for compliance and enforcement of conditions under gas licences.
- The potential to develop unconventional gas in the Cooper Basin is significant. While two shale wells were online and producing in 2014,[22] Santos indicated it could take up to a decade for production to be commercially viable, due to the costs of drilling and extraction technologies, and varying geological conditions.[23]

Policy responses

Policy makers are progressing reforms to help alleviate pressures in the eastern gas market. The gas trading hub at Wallumbilla, Queensland, launched in March 2014 aims to alleviate bottlenecks by facilitating short term gas trades (section 3.5).

In other developments, the COAG Energy Council is reforming pipeline capacity trading arrangements, to promote trade in idle contracted capacity. Throughout the year, some pipelines have significant idle capacity that is contracted to gas retailers and industrial consumers. So, in 2014 the Energy Council and AEMO consulted with stakeholders on enhancing pipeline capacity trading information on the bulletin board. As a preliminary step, AEMO in 2014 improved the bulletin board's interface to improve accessibility and data discoverability. It also launched an eastern market capacity listing service, with voluntary standard contractual terms and conditions for secondary capacity trade.

Pipeline entities also made progress towards secondary trading in capacity. APA Group launched an operational transfer capacity trading platform in 2014, and Jemena expects to launch a trading platform in December 2014. Customers have not widely used existing platforms, with some participants suggesting prices of around $1 per gigajoule are too high.

The AEMC in September 2013 proposed further market reforms, including refining spot market design and streamlining the processes for making rule changes affecting spot markets.[24] AEMO progressed reforms to interregional trade in 2013–14 by improving the interface between the Victorian spot market and interconnecting pipelines and facilities. It similarly progressed reforms to the provision of market operator (gas balancing) services in the short term trading market.[25]

The Australian Government's 2014 energy green paper cited a need for gas production potential and trading information (including prices) to be more transparent, to improve gas market operation.[26] Additionally, stakeholders in 2014 called for closer harmonisation of the gas spot market models. Three spot market models operate in eastern Australia—the short term trading market in Brisbane, Sydney and

21 Grattan Institute, *Gas at the crossroads*, October 2014, p. 9.

22 Santos, *2014 CLSA investors' forum presentation*, 15 September 2014.

23 'Shale gas success still a decade away for Australia, says Santos,' *The Australian*, 26 September 2014.

24 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.

25 AEMO, *2014 Annual report*, 2014.

26 Australian Government (Department of Industry), *Energy green paper*, September 2014.

Adelaide; the Victorian spot market; and the gas supply hub at Wallumbilla.

The existence of these multiple market structures imposes a significant regulatory burden on participants. The Business Council of Australia noted an absence of standardisation across markets works against the development of a viable forward market in gas.[27] The Victorian Government recently advocated more integrated market arrangements, including a possible move to a single market design to reduce barriers to interregional trading. It also advocated a single set of principles for access to east coast pipelines.[28]

3.5 Spotlight—Wallumbilla gas supply hub

As part of the Australian Government's energy market reform program, a gas supply hub at Wallumbilla, Queensland commenced in March 2014. The hub is a pipeline interconnection point for the Surat–Bowen Basin, linking gas markets in Queensland, South Australia, NSW and Victoria (figure 3.8).

The hub promotes transparent and efficient gas trading, allowing participants to manage the risks associated with variable gas prices. It also deepens market liquidity by attracting participants such as LNG plants, industrial customers and gas powered generators. The diversity of contract positions and the number of participants at Wallumbilla create a natural point of trade.

The hub uses a brokerage model allowing buyers and sellers to trade spot or forward gas products (table 3.3) through a voluntary gas trading exchange. The mechanism sits alongside bilateral contracts for balancing gas requirements. The hub facilitates separate trades for the delivery of gas at Wallumbilla's three delivery points—the South West Queensland, Roma to Brisbane and Queensland Gas pipelines. In-pipe trades (whereby gas can be delivered and receipted at separate points) are available for the Roma to Brisbane Pipeline.

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

27 Business Council of Australia, *Australia's energy advantages*, November 2014.

28 Victorian Government (Department of State Development, Business and Innovation), *Victoria's energy statement*, 2014.

Figure 3.8

Gas pipelines and production facilities near Wallumbilla, Queensland

Sources: AER; AEMO.

Membership and trading on the gas supply hub are voluntary. As for other spot markets, the AER monitors and enforces compliance with the market conduct rules, which include a prohibition of non-delivery and price manipulation. This role is the AER's first assigned role in monitoring price manipulation in Australia's energy market.

3.5.1 Gas supply hub activity in 2014

Trading activity in the gas supply hub was intermittent during 2014, which is not unusual in a new market. While the market has several participants (table 3.4), many did not trade in 2014. It had few active sellers, with a single seller accounting for the bulk of sales at times. But the number of buyers and sellers rose during the year, with more sellers than buyers in October 2014 (figure 3.9).

Of the four products traded (table 3.3), liquidity in terms of participant numbers was usually higher for day-ahead and daily products than for balance-of-day and weekly products (figure 3.10).

Volumes have varied from no trades on some days to 105 TJ for a single product on 4 September (figures 3.11

Table 3.3 **Products traded at Wallumbilla gas supply hub**

PRODUCT	DELIVERY TIMEFRAME
Balance-of-day (spot)	For trading on the gas day for delivery in remaining hours of that day
Day-ahead (spot)	For trading on the day before the delivery gas day
Daily (future)	For trading two to seven days before the delivery gas day
Weekly (future)	For trading that starts on a Saturday four weeks before the commencement of the weekly delivery period and closes on the Friday before the commencement of the week

Source: AEMO.

and 3.12). On average, around 12 trades per week occurred between four participants. The intermittent activity is attributable to a number of factors, including the immaturity of the market, the existence of long term contracts, and physical pipeline constraints.

Many businesses initially registered as viewing participants, intending to register later as trading participants. This approach allowed them to access information on trading activity, including traded products, quantities and prices. More generally, some businesses did not identify a need to use the gas supply hub to balance their gas requirements, given their long term contracts.

In terms of delivery points, a majority of trades have been for gas delivered along the Roma to Brisbane Pipeline (figure 3.11). Participants indicated the in-pipe trade facility, along with the greater rights to deliver and receive gas, favours trades on this pipeline compared with others. But damage to the Roma to Brisbane Pipeline in June 2014 reduced its capacity, appearing to impact the frequency and size of trades. Trading on the South West Queensland Pipeline rose from August 2014: its highest recorded volume of 105 TJ was traded for a weekly product on 4 September.

Consistent with spot prices in the Brisbane hub of the short term trading market, prices in the Wallumbilla hub fell during 2014, reflecting sales of large amounts of ramp-up gas from LNG projects (figures 3.11 and 3.12).

Industry participants expect liquidity in the hub to improve in 2015, with pipeline augmentations and market conditions around Wallumbilla expected to free up greater volumes of gas for trade. The ongoing development of hub products should further promote trade.

Capacity expansions on the pipelines serving the hub were expected to be completed in 2014. Jemena's project to

Table 3.4 **Trading and viewing participants at Wallumbilla gas supply hub**

TRADING PARTICIPANTS	VIEWING PARTICIPANTS
AGL Wholesale Gas	Australia Pacific LNG Marketing
BP Australia	APT Petroleum Pipelines
Braemar Power Project	Arrow Energy Trading
Incitec Pivot	BHP Billiton Petroleum (Bass Strait)
Origin Energy Retail	EnergyAustralia
Santos QNT	Esso Australia Resources
Stanwell Corporation	Intelligent Energy Systems
Walloons Coal Seam Gas Company	Oakey Power Holdings
	Macquarie Bank
	Santos Toga
	Australian Competition & Consumer Commission
	Department of Industry

Source: AEMO.

increase capacity on the Queensland Gas Pipeline by 10 TJ is expected to create opportunities for trade on this heavily contracted pipeline (which has had no trades to date). APA Group's project to enhance the bi-directional flow capability of the South West Queensland Pipeline will also facilitate gas trade between south east Australia and Queensland. Further, gas flows on the pipeline will be reversible almost instantaneously in response to market changes.

Increased volumes of gas produced for LNG projects will likely be made available for trade through the gas supply hub during the ramp-up phase. As the six LNG trains approach completion over the next two years, fluctuating volumes of ramp-up gas will likely be offered into the hub. This outcome was observed in 2014, with QCLNG offering gas for trade into the gas supply hub alongside its first train nearing completion.

Once LNG exports commence from Gladstone, a domestic oversupply scenario may eventuate if an LNG train trips. In this scenario, gas would be diverted from Gladstone, to be flared, stored or sold in the domestic market. As a result, large volumes might be traded through the hub. One of the gas supply hub's market benefits is its ability to help manage an oversupply event.

Forecast changes in the domestic market may also impact on activity in the hub. AEMO projects a fall in domestic gas demand in Queensland in 2015, including lower demand for Roma to Brisbane Pipeline services. Stanwell took its Swanbank E generator offline in December 2014 and BP intends to shut its Bulwer Island refinery from mid-2015. Each sourced its gas requirements under long term

Figure 3.9

Number of buyers and sellers, Wallumbilla gas supply hub

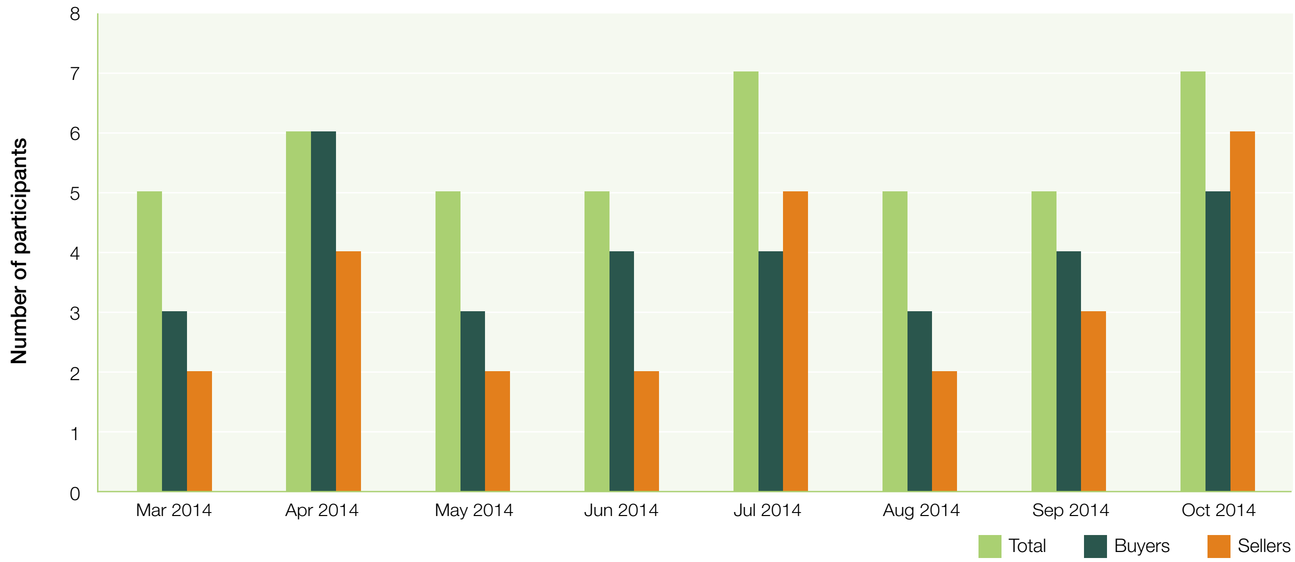
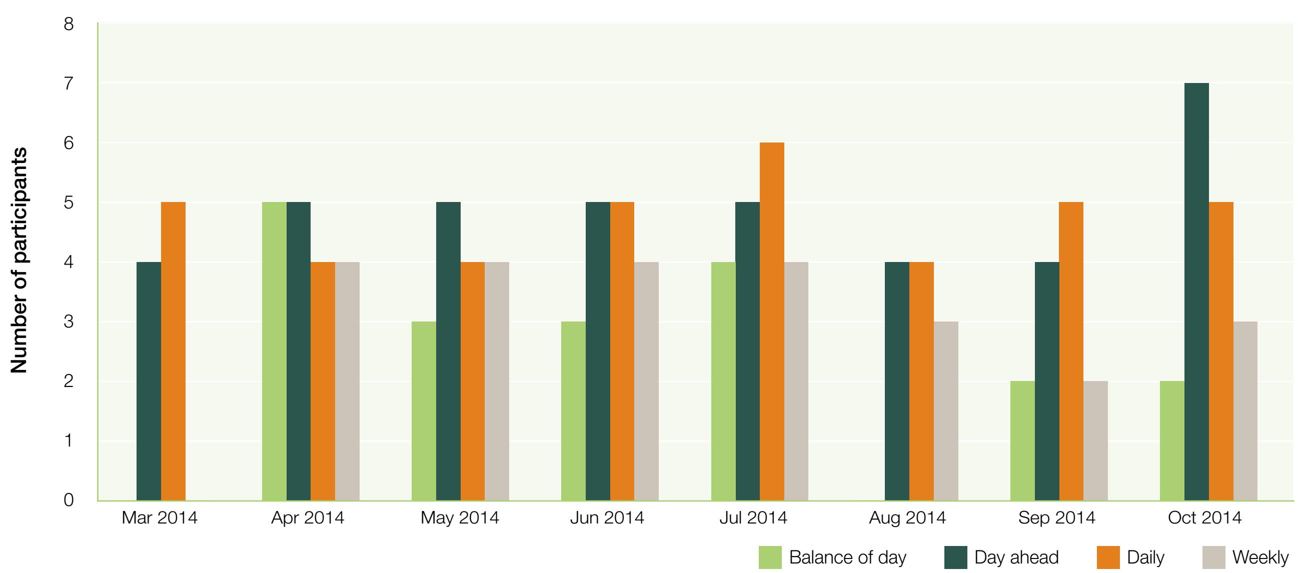


Figure 3.10

Number of participants per product traded, Wallumbilla gas supply hub



Sources (figures 3.9 and 3.10): AER; AEMO.

Figure 3.11

Gas volumes and prices, Wallumbilla gas supply hub

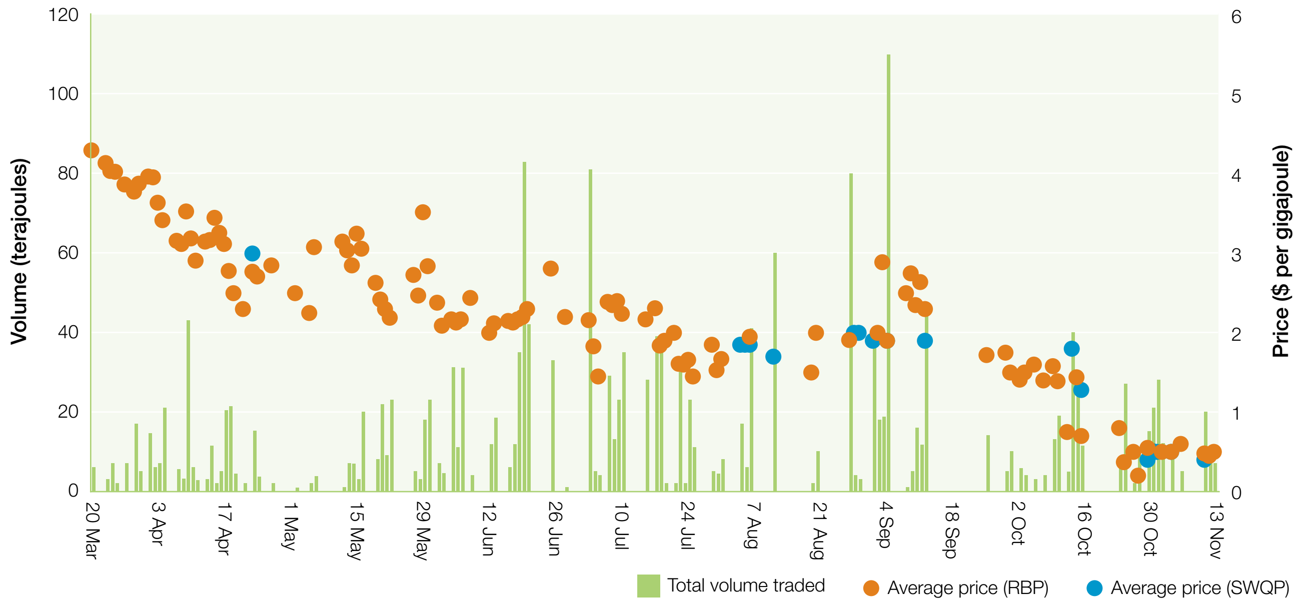
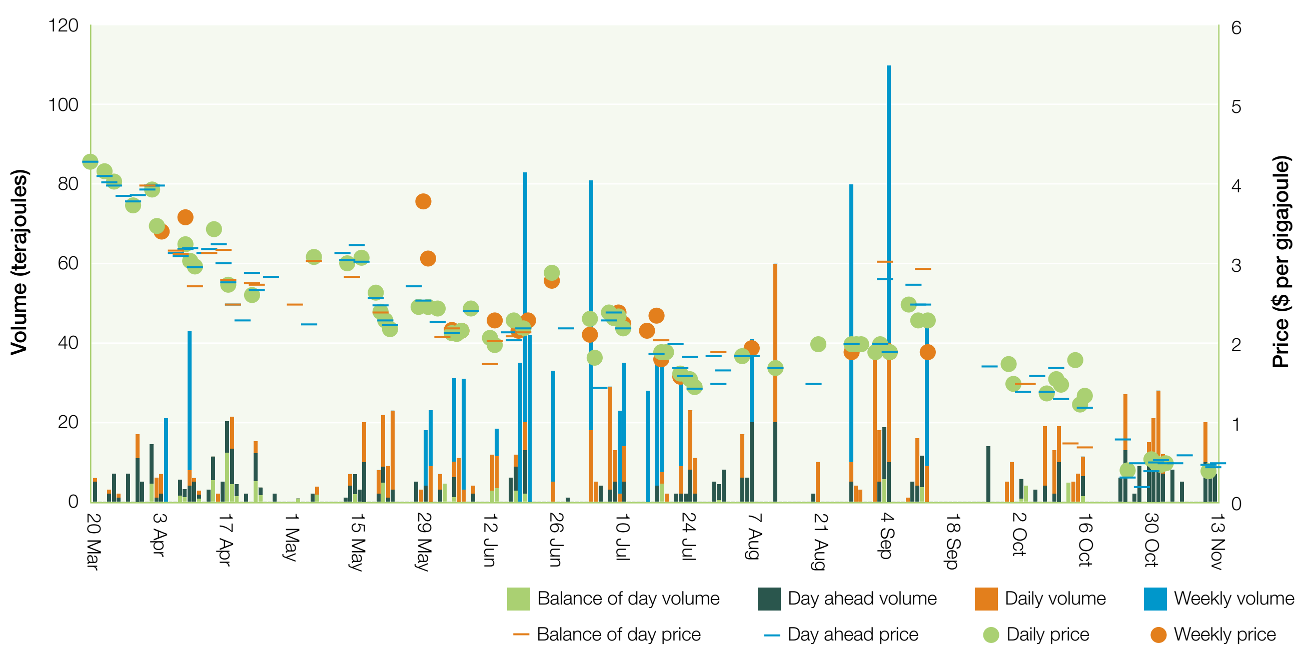


Figure 3.12

Gas volumes and prices per product, Wallumbilla gas supply hub



Sources (figures 3.11 and 3.12): AER; AEMO.

contracts, so these changes will reduce gas demand in Brisbane and on the pipeline by around 80 TJ. With weaker gas demand in Queensland, more gas may be sold through the hub to southern markets via the South West Queensland Pipeline.

In June 2014 Argus Media began reporting a month-ahead price index for gas delivered to Wallumbilla, based on information from buyers and sellers actively trading in the hub. Traders can use the index to predict forward gas prices. Additionally, a hub reference group is finalising an end-of-day reference price that may later be used for exchange based futures products.

Price indexes, end-of-day reference pricing, and futures products are signs of growing maturity in the hub, with opportunities emerging for participants to hedge exposure to prices. While these developments will likely increase liquidity in the hub, a number of participants indicated the availability of a single trading price would further enhance liquidity. Participants indicated improved interconnection between transmission pipelines would also promote gas flows within the hub.

Participants also reported the availability of long term contracts has been diminishing in the market. This claim is consistent with the findings of a 2013 Australian Industry Group survey, in which some industrial users claimed to be unable to enter contracts for five years or more 'at any price'. With less gas locked up in domestic contracts, more is being contracted on a shorter term basis. This new contractual environment will likely free up more gas for trade through the hub.

Despite intermittent volumes to date, gas powered generators, LNG producers and industrial customers remain supportive of the gas supply hub. While a number of businesses are still not trading, they consider the hub provides a flexible and fit-for-purpose platform for trading in gas products. In particular, they suggest its voluntary nature and competitive registration fee delivers favourable low market entry costs, particularly compared with the short term trading market.