4 Gas markets in eastern Australia

The main types of gas produced in Australia are conventional natural gas and coal seam gas (CSG). Conventional gas is found trapped in underground reservoirs, often along with oil, while CSG is an unconventional form of gas extracted from coal beds. Advancements in extraction techniques have improved the commercial prospects for other forms of unconventional gas, including shale and tight gas.[1]

The supply of gas to energy customers involves several steps (infographic 2). It begins with the exploration and appraisal of potential reserves for commercial viability. Gas discoveries are extracted through wells, then processed to separate the methane and ethane from impurities (such as nitrogen, carbon dioxide and sulphur dioxide) and to remove and treat any water.

In eastern Australia around 70% of gas produced is converted to liquefied natural gas (LNG) for export, mainly to Asia. The balance is sold into the domestic market. Some gas is stored (often in depleted gas fields or LNG tanks) and can be used to augment supply at peak times. More recently, domestic gas users have explored options for importing LNG to supplement domestic gas supplies.

Gas sold to domestic customers is transported from production fields to major demand centres or hubs via high pressure transmission pipelines (figure 4.1). The pipelines have wide diameters and operate under high pressure to optimise shipping capacity. They deliver gas to power stations, large industrial and commercial customers, and energy retailers, which sell the gas to their customers. Retailers deliver gas to energy customers' pipelines via distribution networks, which are spaghetti-like networks of smaller pipes that service commercial and residential premises in cities and towns.

4.1 Gas markets in eastern Australia

This chapter considers the 'upstream' gas sector, encompassing gas production, wholesale markets for gas, and the transport of gas along transmission pipelines to demand hubs. It focuses on the eastern gas market, in which the Australian Energy Regulator (AER) has regulatory responsibilities (box 4.1). Chapter 5 covers regulated transmission and distribution pipelines, while chapter 6 covers gas (and electricity) retailing.

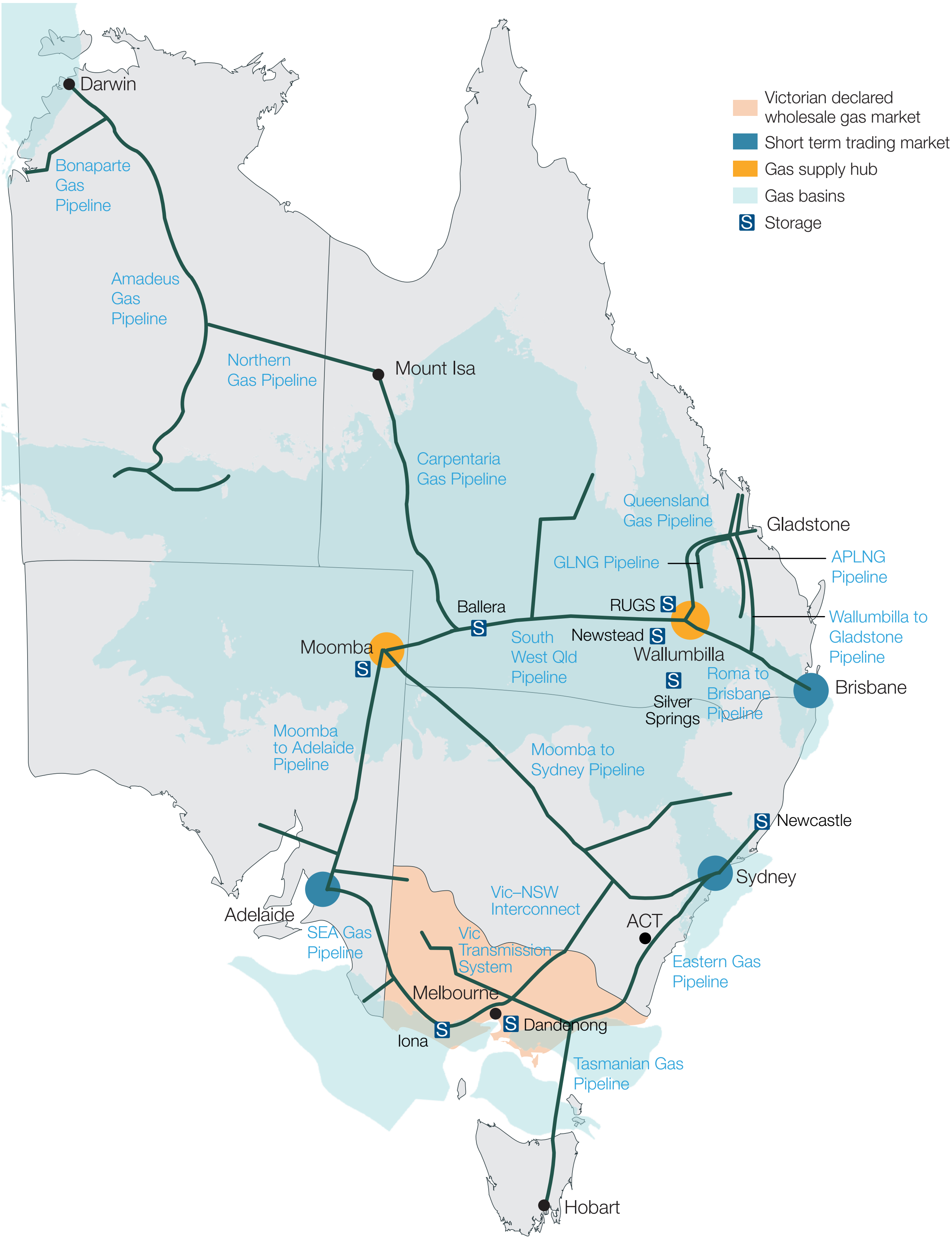
The eastern gas market encompasses Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). This market is interconnected by transmission pipelines, which source gas from basins and deliver it to large industrial customers and major population centres. The main production basins are the Surat–Bowen Basin in Queensland, the Cooper Basin in north east South Australia, and 3 basins off coastal Victoria, the largest being the Gippsland Basin. Since January 2019 the market has also sourced gas from the Northern Territory.

The eastern gas market evolved as separate state-based markets, each served by a single gas basin and a single transmission pipeline. Over the past 20 years, new pipelines interconnected these markets, making it possible to transport gas from Queensland to the southern states and (since key pipelines became bi-directional) vice versa. With the opening in 2019 of the Northern Gas Pipeline, the eastern gas market can also source gas from the Bonaparte Basin off the north coast of Western Australia and the Northern Territory.

In 2015 gas became a major export industry in eastern Australia with the launch of Queensland's LNG industry. The industry transformed the eastern gas market by giving producers the choice of exporting gas or selling it domestically. By 2018 over 60% of eastern Australian gas production was being exported. With domestic users now competing with overseas customers to buy Australian gas, prices in the domestic market have shifted to align more closely with international gas prices. Shifting gas prices also impact electricity markets, which rely on gas powered generation to firm output from weather-dependent renewable generation and at times of peak electricity demand.

1 Shale gas is contained within organic-rich rocks such as shale and fine grained carbonates, rather than in underground reservoirs. The application of horizontal drilling techniques in the past 5 years is enhancing the economic viability of shale gas development. Tight gas is found in low porosity sandstone and carbonate reservoirs.

Figure 4.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

Box 4.1 The AER's role in gas markets

The Australian Energy Regulator (AER) has regulatory responsibilities across the entire gas supply chain in eastern Australia. At the wholesale level, we monitor and report on spot gas markets in Sydney, Brisbane, Adelaide and Victoria; gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia); and activity on the Gas Bulletin Board, which is an open access information platform covering the eastern gas market.

We monitor the markets and bulletin board to ensure participants comply with the National Gas Law and National Gas Rules, and we take enforcement action when necessary. Our compliance and enforcement work aims to promote confidence in the gas market, to encourage participation. We also monitor the markets for particular irregularities and wider inefficiencies. Our monitoring role at the Wallumbilla and Moomba hubs, for example, explicitly looks to detect price manipulation. In 2019 we began a new role as the compliance and enforcement body for a scheme to auction underused capacity in transmission pipelines.

Our gas compliance focus in 2020 included the successful implementation of capacity trading reforms and enhanced transparency. In particular, market participants are required to submit information to the Australian Energy Market Operator (AEMO) and the AER in a timely and accurate manner. During the year, we gave significant focus to the day-ahead auction, which facilitates the daily trade of contracted but un-nominated pipeline capacity. We closely monitored auction activity, monitoring for misconduct and for compliance with record keeping requirements. We will continue this focus throughout 2021.

In 2020 we continued our monitoring and reporting activities, publishing weekly reports, gas industry statistics and our *Wholesale markets quarterly* reports, which cover gas spot market activity, prices and liquidity. The quarterly reports also include analysis of eastern Australia's liquefied natural gas (LNG) export sector and its impact on the domestic market.

Looking forward, we continue to engage with the Energy Ministers' gas reform agenda. Under the agenda, we must administer new reporting obligations to enhance the transparency of market activity.

Alongside our work in gas wholesale markets, the AER is the economic regulator for 2 major transmission pipelines in eastern Australia and one pipeline in the Northern Territory. We also arbitrate disputes relating to 'light regulation' pipelines, and we may appoint an arbitrator to settle disputes affecting other pipelines.[2]

In the downstream gas industry, the AER sets reference prices for distribution networks in NSW, Victoria, South Australia and the ACT (chapter 5). In retail gas markets, we hold wide-ranging responsibilities in jurisdictions that have passed the National Energy Retail Law – namely, Queensland, NSW, South Australia and the ACT (chapter 6).

Across the gas sector, we also draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities. When appropriate, we propose or participate in reforms to improve the market's operation.

Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory but plays no role in the territory's wholesale market. However, facility operators in the Northern Territory must report gas flow activity to the Gas Bulletin Board, which the AER oversees. We have no regulatory function in Western Australia, where separate laws apply.[3]

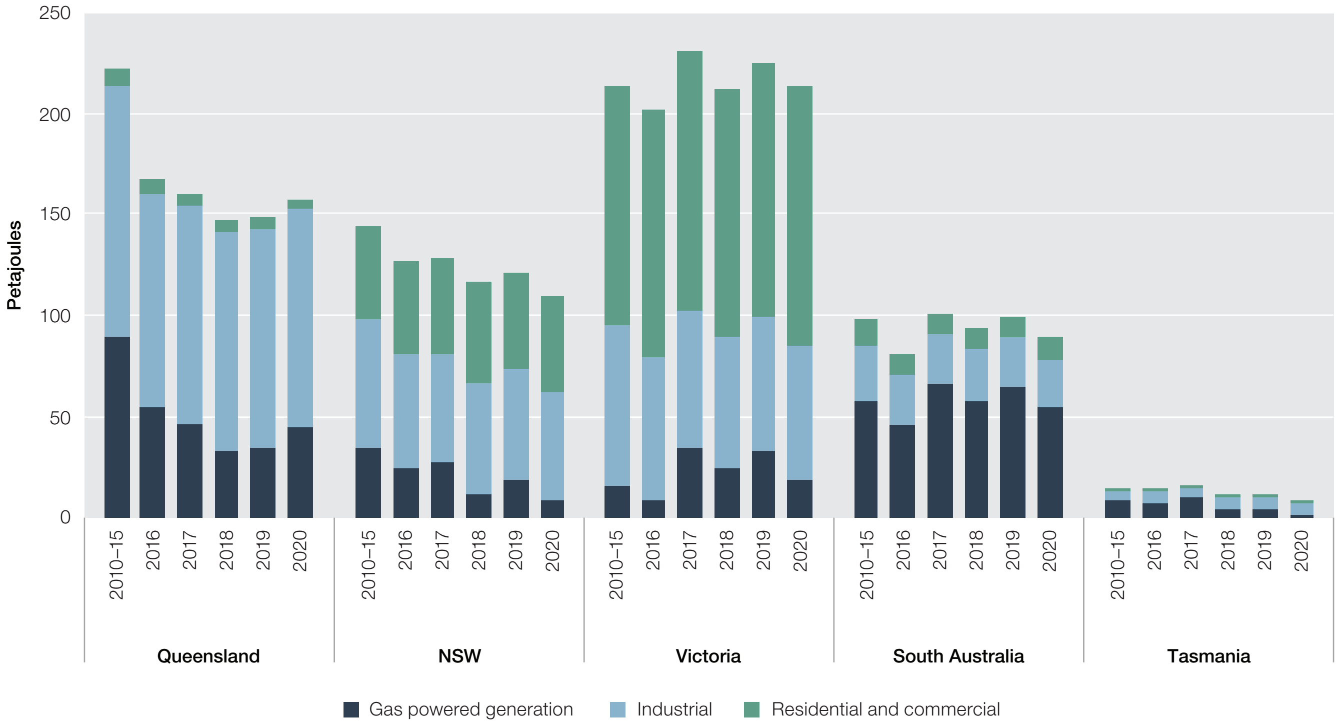
2 Chapter 5 outlines the different tiers of pipeline regulation.

3 The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia, and AEMO operates a spot gas market there.

4.2 Gas demand in eastern Australia

Domestic customers in eastern Australia used around 580 petajoules (PJ) of gas in 2020 (figure 4.2).[4] These customers included industrial businesses, electricity generators, commercial businesses and households. Industrial customers are the biggest users, consuming 45% of gas sold to the domestic market. They use it as an input to manufacture pulp and paper, metals, chemicals, stone, clay, glass and processed foods. Gas is also a major feedstock in ammonia production for fertilisers and explosives.

Figure 4.2 Gas consumption in eastern Australia



Note: Data for 2010–15 are average annual consumption over that period.

Source: AEMO, 2021 gas statement of opportunities, March 2021.

The electricity sector is another major source of demand. The rapid responsiveness of gas powered turbines makes them suitable for peak electricity generation. Gas powered generation also plays an important role in managing fluctuations in wind and solar generation. With gas generation often used to fill supply gaps in the electricity market, its level can fluctuate significantly. Gas powered generation accounted for 21% of domestic gas use in 2020, down from 29% in 2017 when gas generators helped fill the supply gap caused by the closure of Victoria's Hazelwood power station. South Australia has the highest demand for electricity generation, accounting for 43% of eastern Australian gas powered generation demand in 2020.

Residential and commercial customers are the third major source of gas demand. Overall, they account for 34% of domestic gas demand. Victoria is the only state where a majority of demand (more than 60%) is from small residential and commercial customers, who use gas mostly for heating and cooking. In 2016 over 80% of Victorian households were connected to a gas network. That same year residential gas penetration was around 80% in the ACT, 60% in South Australia, 45% in NSW, 10% in Queensland and 6% in Tasmania.[5] More recently some regions look to be reducing gas connections. In 2020 in the ACT, for example, policy changes mean new developments are no longer required to connect to the gas network.[6]

In the overall energy mix, gas reliance is highest in South Australia, where it accounts for 35% of primary energy consumption, followed by Victoria and Queensland (around 20% in each state). It is lower in NSW, where it accounts for less than 10% of energy consumption.[7] South Australia's high degree of reliance on gas reflects its dependence on gas powered electricity generation.

4 Excludes LNG. AEMO, *2021 gas statement of opportunities*, March 2021.

5 AEMO, *National gas forecasting report*, December 2016.

6 ACT Government, 'Now we're cooking with … electricity! Gas no longer a requirement in Canberra suburbs' [media release], January 2020.

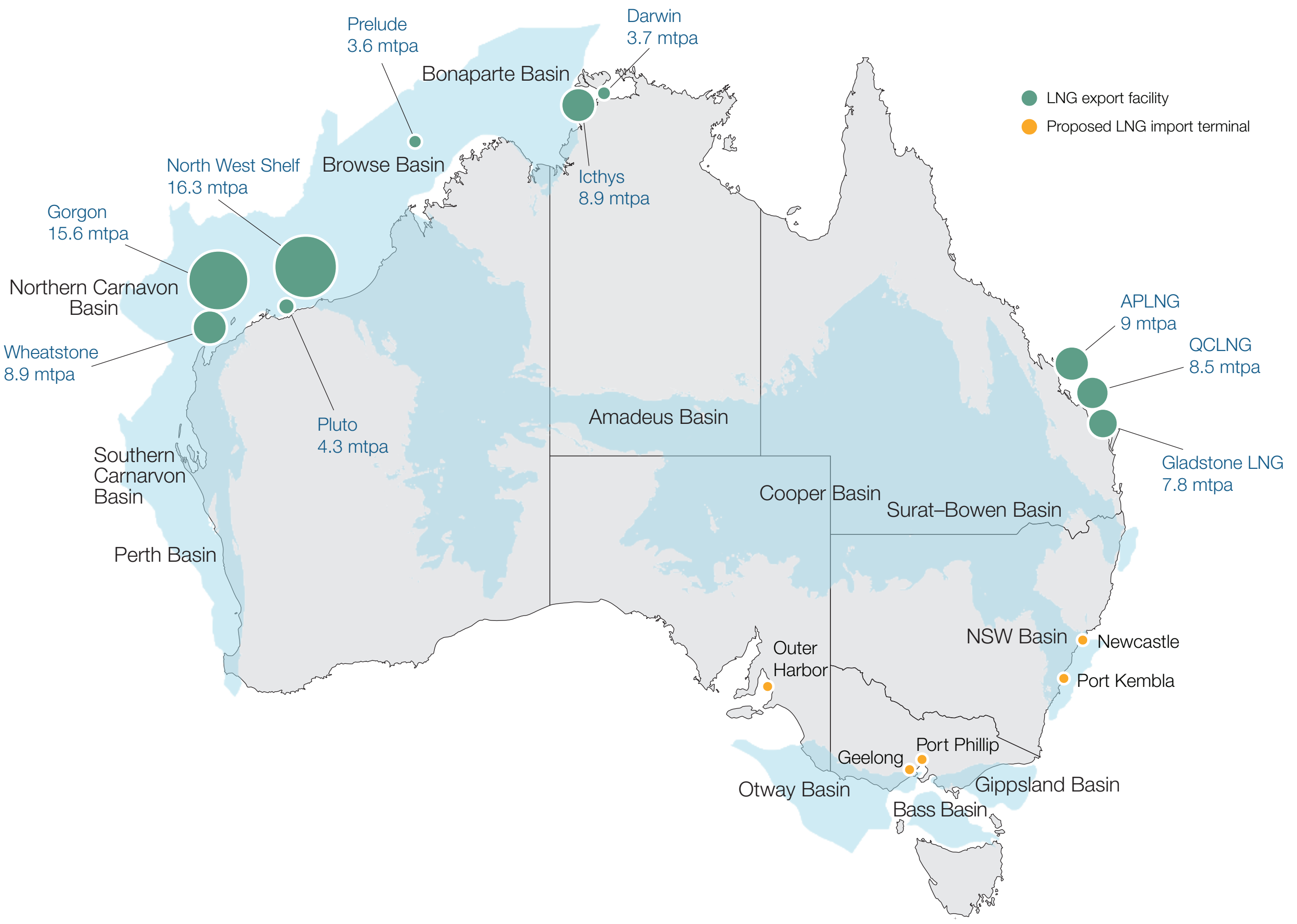
7 Department of Industry, Science, Energy and Resources, *Australian energy update 2020, Australian energy statistics*, September 2020, Table C.

4.3 Liquefied natural gas exports

A majority of gas produced in eastern Australia is liquefied in processing facilities in Queensland for shipping to export markets (table 4.1). The gas is chilled to –162° C, which shrinks volume by 600 times and makes it economic to store and ship in large quantities. Most Australian LNG is shipped to Asia.

Alongside Queensland's LNG industry, Australia operates 5 LNG projects in Western Australia and 2 in the Northern Territory (figure 4.3). In 2019–20 LNG exports earned Australia nearly $50 billion, making gas Australia's second largest resource and energy export behind iron ore.[8] Australia became the world's largest LNG exporter in 2019.[9]

Figure 4.3 Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa).

Source: AER.

4.3.1 Queensland liquefied natural gas industry

Queensland's LNG industry comprises 3 major projects, which liquefy gas sourced mainly from the Surat–Bowen Basin. The projects were made possible by the basin's vast CSG reserves and are the world's first to convert CSG to LNG. The LNG projects control over 80% of reserves in eastern Australia (mostly CSG), and they use these reserves to meet a majority of their LNG requirements.[10] They also source gas from other LNG producers, as well as producers in central Australia and Victoria, and acquire it through long term contracts and spot markets:

- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). It began exporting LNG in January 2015 and has 2 trains (liquefaction and purification facilities). Shell is the principal owner (73.75%).

8 Department of Industry, Innovation and Science, *Resources and energy quarterly*, December 2020.

9 EnergyQuest, *EnergyQuarterly*, March 2020.

10 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 35.

- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. It began exporting in October 2015 and has 2 trains. Santos (30%), Petronas and Total (27.5% each) and Kogas (15%) own the project.
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa.[11] It began exporting gas in January 2016 and has 2 trains. Origin Energy and ConocoPhillips (37.5% each) and Sinopec (25%) own the project.

4.3.2 Northern Territory and Western Australia

The Northern Territory's LNG industry began in 2006 with the commissioning of Darwin LNG (3.7 mtpa capacity), which relies on gas from the Bonaparte Basin in the Timor Sea. A second project – Ichthys LNG (8.9 mtpa capacity) – launched in 2018. Both projects connect to the territory's domestic gas market as emergency supply sources but otherwise produce gas solely for export.

Western Australia has 5 LNG projects with a combined capacity of around 50 mtpa. The industry began with the North West Shelf project, and the first cargo left the facility for sale to Japan in 1989. The North West Shelf project has 5 trains and remains Australia's largest LNG project by capacity (16.9 mtpa).

Western Australia's second LNG project, Pluto, was commissioned in 2012. Rising LNG prices provided the impetus for 3 more recent projects – Gorgon (2016), Wheatstone (2017) and Prelude (2019).[12]

4.4 Gas reserves in eastern Australia

Gas reserves are unexploited accumulations of gas that are expected to be commercially recoverable. Data on gas reserves are an important input to forecasting supplies of gas that may enter the market.

Different measures of gas reserves are quoted based on geological, engineering and commercial analysis of the likelihood of successful recovery:

- Proven reserves (1P) are estimated to be at least 90% certain of successful commercial recovery.
- Proven plus probable reserves (2P) are estimated to be at least 50% certain of successful commercial recovery.
- A third category (3P) includes all reserves deemed at least 10% likely to be commercially recoverable.

Lower levels of probability attach to contingent resources, which are resources considered potentially recoverable from known accumulations that are not yet technically or commercially recoverable.

This probabilistic approach to measuring gas reserves results in frequent, and sometimes substantial, adjustments. Queensland's 2P reserves, for example, were downgraded by over 7,177 PJ between June 2017 and June 2020.[13]

Data on Australian gas reserves is collected through various disconnected mechanisms and bodies, resulting in a lack of clear, consistent and accurate reporting. Data standards and aggregation across these sources are inconsistent, and the assumptions underlying the data are often not transparent.[14]

The Australian Securities Exchange (ASX) requires listed companies to report limited data on gas reserves, but unlisted companies and those listed overseas are not obliged to report. State and territory governments each have reporting requirements, and the Australian Government collects some information (particularly on offshore resources), but much of this information is commercial-in-confidence.

Market analysts such as EnergyQuest and Energy Edge publish reserves estimates, drawing on available sources. The Australian Competition and Consumer Commission (ACCC) also reports on the gas market and began publishing reserves and resources information in December 2018.

In 2020, Energy Ministers were progressing reforms that would require all participants to report information on gas reserves via the Gas Bulletin Board (section 4.14.1).

11 APPEA, *LNG exports*, APPEA website, accessed 28 May 2021.
12 Department of Jobs, Tourism, Science and Innovation (WA), *Western Australia liquefied natural gas profile*, February 2020.
13 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 31.
14 ACCC, *Inquiry into the east coast gas market*, April 2016.

4.4.1 Distribution of reserves in eastern Australia

EnergyQuest estimated eastern and southern Australia's 2P gas reserves stood at 35,444 PJ in February 2021 but noted this estimate is subject to uncertainty (table 4.1).[15] Reserve ownership is highly concentrated in some basins but more diverse across the market as a whole (figure 4.4). Arrow Energy (jointly owned by Shell and PetroChina) is the single largest holder of 2P reserves in eastern Australia (17%). Other major reserve holders include Origin Energy, ConocoPhillips, Sinopec and Santos.[16]

Table 4.1 Gas basins serving eastern Australia

	GAS PRODUCTION – 12 MONTHS TO DECEMBER 2020			2P GAS RESERVES (FEBRUARY 2021)	
GAS BASIN	PETAJOULES	SHARE OF EASTERN AUSTRALIAN SUPPLY (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF EASTERN AUSTRALIA RESERVES (%)
Surat–Bowen (Qld)	1,513	76%	2%	30,637	86%
Cooper (SA–Qld)	101	5%	11%	1,048	3%
Gippsland (Vic)	255	13%	0%	1,924	5%
Otway (Vic)	37	2%	–37%	745	2%
Bass (Vic)	11	1%	–2%	166	0%
Sydney, Narrabri, Gunnedah (NSW)	4	0%	–8%	14	0%
Amadeus (NT)	15	1%	–26%	247	1%
Bonaparte (NT)	47	2%	–9%	663	2%
Eastern Australia total	**1,983**		**0%**	**35,444**	
Domestic gas sales	631		–2%		
LNG exports	1,352		1%		

2P: proven plus probable reserves estimated to be at least 50% sure of successful commercial recovery.

Note: Totals may not add to 100% due to rounding. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and 2P reserves in other basins are mainly conventional gas.

Source: EnergyQuest, EnergyQuarterly, March 2021, p 82.

Surat–Bowen Basin

Queensland's Surat–Bowen Basin is the largest basin in eastern Australia, with over 85% of all gas reserves. Reserves from the basin are mainly converted to LNG for export, but the basin also supplies some gas to the domestic market.

Victorian basins

The Gippsland Basin is the most significant of the 3 producing basins in Victoria, accounting for around 5% of eastern and southern Australian reserves.[17] The Bass and Otway basins together account for 2% of reserves. Total reserves across the Victorian basins are declining.

From December 2019 to February 2021, 2P reserves fell by nearly 22% in the Gippsland Basin. Over the same period, 2P reserves fell by 5% in the Bass Basin and rose by 16% in the Otway Basin. Because the Otway Basin is smaller in scale, this increase did not offset the reductions in the Bass and Gippsland basins.

A joint venture between Esso (ExxonMobil) and BHP controls a large majority of reserves in the Gippsland Basin.

15 EnergyQuest, *EnergyQuarterly*, March 2021, p 82.

16 EnergyQuest, *EnergyQuarterly*, March 2021, Table 27, p 83.

17 EnergyQuest, *EnergyQuarterly*, March 2021, Table 26, p 82.

Cooper Basin

The Cooper Basin in central Australia has over 1,000 PJ of 2P reserves, which accounts for 3% of eastern Australia's 2P reserves. In 2010 Santos entered an agreement to supply one of the Queensland LNG projects with 750 PJ of gas over 15 years, which accelerated the depletion of the basin's conventional reserves. Reserves declined by 5% between December 2019 and February 2021.[18]

NSW basins

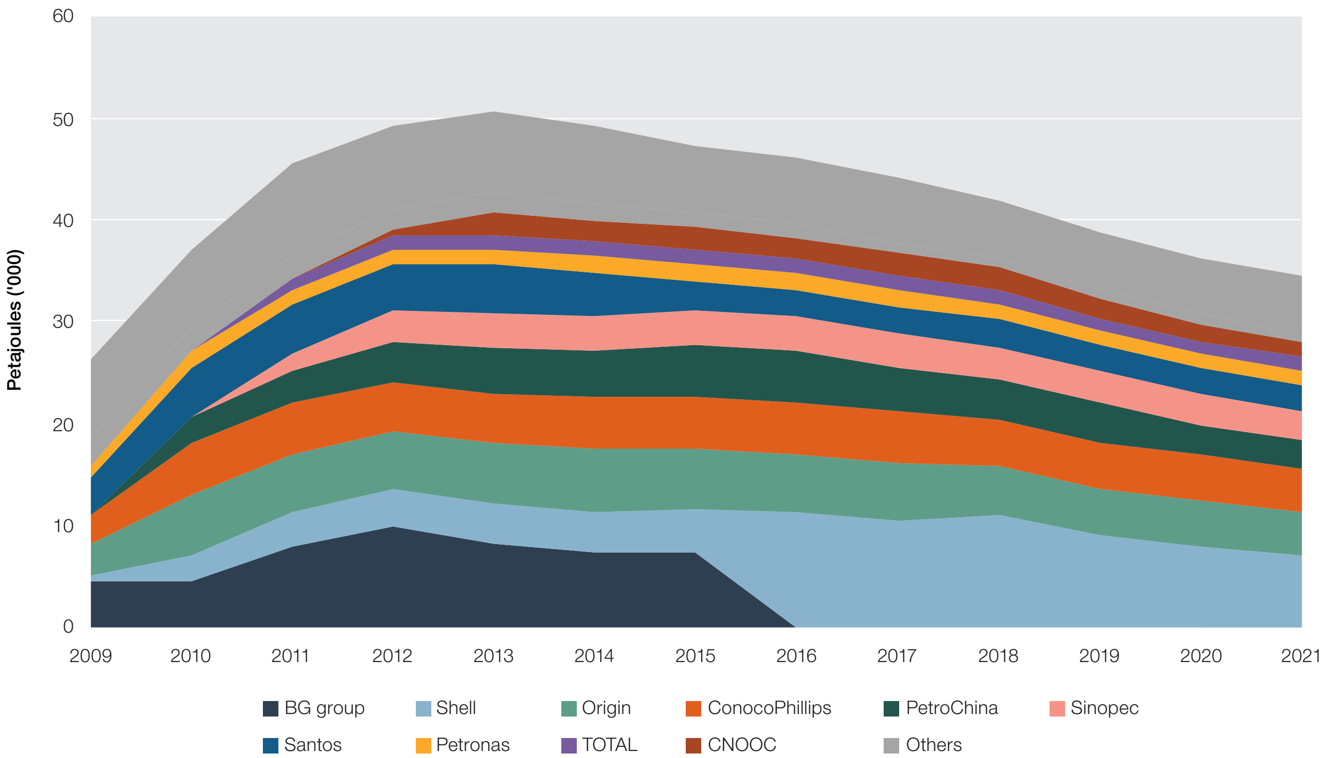
NSW has significant contingent resources (around 1,300 PJ) but only 14 PJ of 2P reserves and negligible current production. In 2017 Santos applied to develop reserves near Narrabri in the Gunnedah Basin. After encountering widespread opposition on environmental grounds, the project received consent from the NSW Independent Planning Commission in September 2020.[19] In November 2020 the Minister for the Environment granted approval to the project, and a final investment decision is expected in late 2021 or early 2022 (section 4.12.1).[20]

Northern Australia

Northern Australia was historically separate from the eastern gas market, but the commissioning of the Northern Gas Pipeline in January 2019 linked gas fields in the Bonaparte Basin (offshore of Darwin in the Timor Sea) and the Amadeus Basin (southern Northern Territory) with Queensland.

The Bonaparte Basin was developed to support the Northern Territory's LNG industry, which is based in Darwin. The basin is estimated to have over 650 PJ of 2P reserves. Most gas produced in the basin is converted to LNG for export. The Amadeus Basin is smaller, with just under 250 PJ of estimated 2P reserves.

Figure 4.4 Market shares in 2P gas reserves in eastern Australia



Note: Aggregated market shares in 2P (proven and probable) gas reserves in the Surat–Bowen, Gippsland, Cooper, Otway, Bass and NSW basins. 2P reserves are those for which geological and engineering analysis suggests at least a 50% probability of commercial recovery.

Source: EnergyQuest, EnergyQuarterly (various years).

18 EnergyQuest, *EnergyQuarterly*, March 2021, Table 26, p 82.

19 Department of Planning, Industry and Environment (NSW), *Narrabri gas*, DPIE website, accessed 28 May 2021.

20 Santos, 'Santos welcomes federal signoff on Narrabri Gas Project' [media release], November 2020.

4.5 Gas production

In 2020 eastern Australia produced almost 2,000 PJ of gas. The majority (68%) was exported as LNG and the remainder was sold to the domestic market (table 4.1).

Queensland's Surat–Bowen Basin supplied 76% of gas produced in eastern Australia in 2020, including much of the gas earmarked for LNG export. Participants in Queensland's 3 LNG projects produced around 90% of the basin's output in 2020. As well as supplying their LNG facilities, the LNG participants sell some gas into the domestic market.

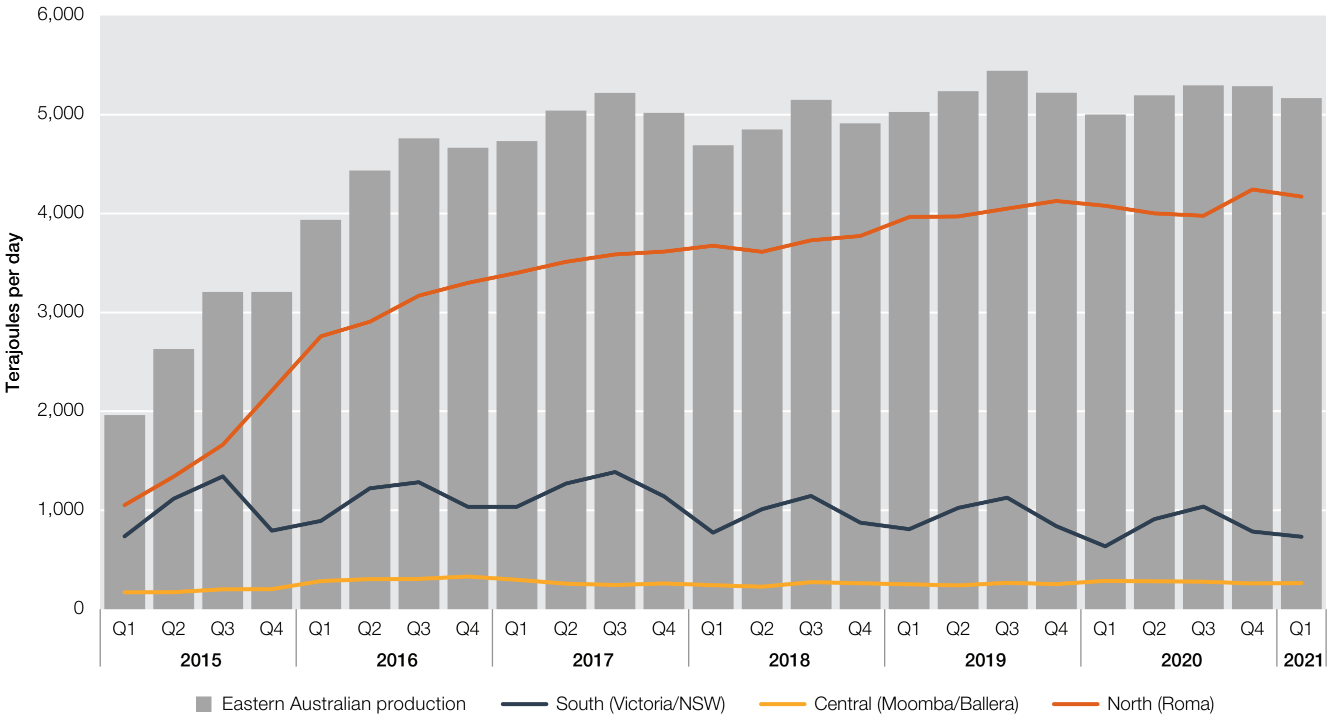
Outside Queensland, the basins off coastal Victoria meet most of the remaining demand in the eastern states. The Gippsland Basin is the most significant of the 3 producing basins in Victoria, meeting 13% of demand in 2020. The smaller Otway and Bass basins jointly supplied 3% of the market.

The Longford Gas Plant, servicing the Gippsland Basin, achieved record high production in 2017, some of which was shipped to Queensland for LNG exports (figure 4.5). But production has since declined. The Australian Energy Market Operator (AEMO) forecasts a steep decline in southern field production after 2022 as a number of Gippsland Basin fields cease production in 2023 and 2024. However, it anticipates that the commissioning of the proposed Port Kembla (NSW) LNG import facility in 2023 will offset this reduction in the short term.[21]

The Cooper Basin in central Australia accounted for 5% of eastern Australian gas production in 2020. The basin plays an important role as a 'swing' producer in managing seasonal and short term supply imbalances in the domestic gas market.

With the opening of the Northern Gas Pipeline in January 2019, the Northern Territory's offshore Bonaparte Basin and onshore Amadeus Basin became new suppliers to the eastern gas market. In 2020 the Northern Gas Pipeline delivered around 56 terajoules (TJ) per day on average into the eastern market – around 62% of its capacity (90 TJ per day).

Figure 4.5 Eastern Australia gas production



Source: AER analysis of Gas Bulletin Board data.

21 AEMO, *2021 gas statement of opportunities*, March 2021, p 44.

4.5.1 Changing basin profiles

Activity in all gas basins across eastern Australia has evolved to meet the needs of the LNG industry. Production from the Surat–Bowen Basin is mainly earmarked for export. But supply from other eastern Australian basins rose between 2015 and 2017 to help LNG projects meet their export contracts. This shift accelerated a depletion of gas reserves in southern basins. High production rates in Victoria also strained production plants, causing outages.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market. In the year to June 2018, Surat–Bowen Basin production growth exceeded LNG export growth. As supplies from the north increased, southern basin production eased from the peaks recorded in 2017. From December 2018 to December 2020, Surat–Bowen Basin production increases (9%) have largely matched LNG export growth (10%). In turn, production in southern basins decreased by a similar proportion (10%). In particular, AEMO and the ACCC have identified the ongoing depletion of southern gas fields as a significant risk to supply in the coming years.

4.6 Gas storage

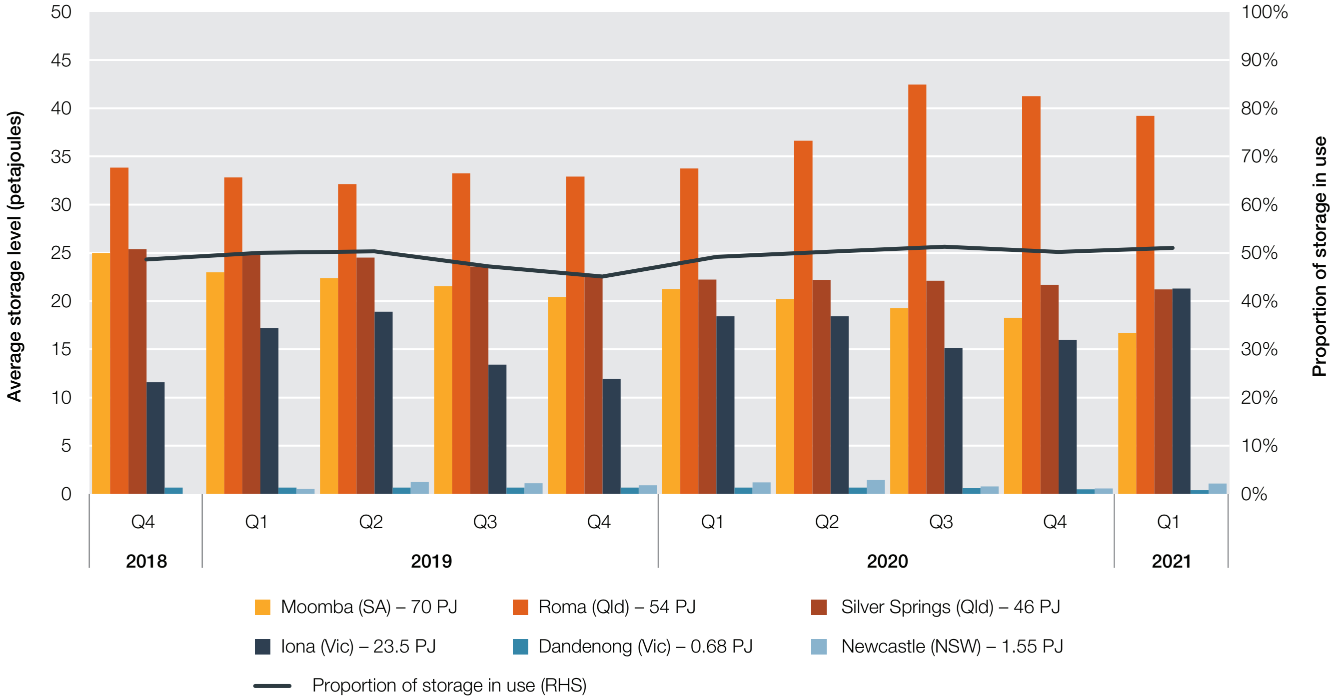
Storage provides a means of conserving surplus gas production for quick delivery when needed. Gas can be stored in its natural state in depleted underground reservoirs and pipelines; or post liquefaction as LNG in purpose-built facilities. Transmission pipelines can also provide gas storage services.

Eastern Australia's gas storage capacity includes:

- large facilities using depleted gas fields in Queensland, Victoria and South Australia
- smaller seasonal or peaking storage facilities located near demand centres – for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria
- short term peak storage services on gas pipelines, which are mostly contracted by energy retailers. The Tasmanian Gas Pipeline, for example, stores gas that can be sold into the Victorian market at times of peak demand.

The importance of storage in managing supply and demand has risen since the LNG industry began operating. Storage levels at the Roma underground, Moomba and Silver Springs facilities have been consistently drawn down to meet LNG export demand. Against this trend, Roma underground storage levels increased from 2019, rising significantly in 2020 when prices were low (figure 4.6). More generally, average storage levels in 2020 were higher than in 2019 despite depleting slightly in late 2020 to assist in meeting record LNG export demand.

Figure 4.6 Gas storage in eastern Australia



Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.
Source: AER analysis of Gas Bulletin Board data.

Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks. For example, AGL contracted to use some of the Iona underground storage facility's capacity from January 2021 to manage seasonal demand. In June 2018 Lochard Energy began to expand its Iona capacity, expecting this storage would help manage future peak demand periods.[22] The Iona facility operates more dynamically that other storage facilities, with a larger capacity to inject and withdraw gas on any given day. As an example, during the third quarter of 2020, Iona storage helped meet South Australian gas demand for electricity generation during a period of low wind output and refilled during a period of milder weather.[23]

In 2021 the ACCC reported on investments to develop or expand storage capacity under consideration.[24] It noted Lochard Energy's expansion at Iona will continue, with a further expansion under consideration. Lochard Energy also purchased depleted shore reservoirs near Iona, which it could use for storage development. Further, production is anticipated shortly from the Golden Beach gas field in the Gippsland Basin, which may include a storage facility that could inject gas into the Victorian transmission system at Longford. A final investment decision on the storage component of this project is anticipated in 2021, with storage capacity becoming accessible from 2023.[25]

4.7 Gas transmission pipelines

Wholesale customers buy capacity on transmission pipelines to transport their gas purchases to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (key pipelines are listed in table 4.2, with routes shown in figure 4.1). Dozens of smaller pipelines fill out the transmission grid.

Historically the eastern gas market's transmission system was a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre. Over time the system evolved into an integrated network covering eastern and southern Australia. Many gas pipelines became bi-directional, and gas increasingly flows across multiple pipelines to reach its destination. These changes mean access to capacity on key pipelines is more important than ever.

Investment in transmission pipelines is expensive and normally underwritten by foundation shippers through long term contracts. After its initial construction, a pipeline can be incrementally expanded to meet rising demand through compression, looping (duplication of parts of the pipeline) and extensions.

In recent years significant transmission investment occurred to meet the needs of Queensland's LNG industry, which included expanding existing pipelines and constructing new pipelines to ship gas to LNG processing facilities. Among recent developments, the Roma North Pipeline and the Atlas Gas Pipeline were commissioned in 2019, and other pipelines are proposed to bring additional supply to the eastern markets. Additionally, Jemena's Northern Gas Pipeline (which began operations in January 2019) provides eastern Australia's pipeline interconnection with the Northern Territory, making it possible to ship gas produced in the territory basins to eastern Australia (section 4.12.3).

The range of services provided by transmission pipelines is expanding to meet the needs of industry as the market evolves. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements such as bi-directional and backhaul shipping, and park and loan services.[26]

Transmission pipelines are separately owned from gas production companies. A gas customer must negotiate with a gas producer to buy gas, and separately contract with one or more pipeline businesses to get the gas delivered. This separation adds a layer of complexity to sourcing gas, especially for smaller customers (section 4.10.4).

4.7.1 Pipeline ownership

Australia's gas transmission sector is privately owned (table 4.2). The publicly listed APA Group is the largest player, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Other major pipeline owners include Jemena and Singapore Power International.

22 The Hon Daniel Andrews MP (Premier of Victoria), 'Securing gas for future winter warmth' [media release], June 2018.

23 AEMO, *Quarterly energy dynamics Q3 2020,* October 2020.

24 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 53.

25 EnergyQuest, *EnergyQuarterly*, March 2021, Table 5, p 27.

26 Pipelines with bi-directional flows can ship gas in both directions. Backhaul shipping is the 'virtual transport' of gas in a direction opposite to the main flow of gas. Parking gas is a way of temporarily storing gas in the pipeline by injecting more than is to be withdrawn. Loaning gas allows users to inject less gas into the pipeline than is to be withdrawn.

Table 4.2 Key gas transmission pipelines in eastern and northern Australia

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/DAY)	REGULATORY STATUS[1]	OWNER
Roma (Wallumbilla) to Brisbane	Qld	438	211 (125)	Full regulation	APA Group
South West Queensland Pipeline (Wallumbilla to Moomba)	Qld–SA	937	404 (340)	Part 23 regulation	APA Group
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	627	140 (40)	Part 23 regulation	Jemena (State Grid 60%, Singapore Power 40%)
Carpentaria Pipeline (South West Qld to Mount Isa)	Qld	840	119	Light regulation	APA Group
GLNG Pipeline (Surat–Bowen Basin to Gladstone)	Qld	435	1,430	15 year no coverage	Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15%
Wallumbilla Gladstone Pipeline	Qld	334	1,588	Part 23 and 15 year no coverage	APA Group
APLNG Pipeline (Surat–Bowen Basin to Gladstone)	Qld	530	1,560	15 year no coverage	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%
Moomba to Sydney Pipeline	SA–NSW	2,029	489 (120)	Partial light regulation / partial Part 23 Regulation[2]	APA Group
Moomba to Adelaide Pipeline	SA	1,184	241 (85)	Part 23 regulation	QIC Global Infrastructure
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	797	358	Part 23 regulation	Jemena (State Grid 60%, Singapore Power 40%)
Vic–NSW Interconnect	Vic–NSW		223 (150)	Part 23 regulation	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	680	314	Part 23 regulation	APA Group 50%, Retail Employees Superannuation Trust 50%
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	734	129 (120)	Part 23 regulation	Palisade Investment Partners
APA Victorian Transmission System	Vic	1,992	1,030	Full regulation	APA Group
Northern Gas Pipeline (Tennant Creek to Mount Isa)	NT–Qld	622	90	Part 23 regulation	Jemena (State Grid 60%, Singapore Power 40%)
Bonaparte Pipeline	NT	287	80	Part 23 exemption	Energy Infrastructure Investments (APA Group 19.9%, Marubeni 49.9%, Osaka Gas 30.2%)
Amadeus Gas Pipeline	NT	1,626	120	Full regulation	APA Group

km: kilometres; TJ/day: terajoules per day.

1 Full regulation pipelines have their prices assessed by the AER. Light regulation pipelines do not have their prices assessed by the AER, but parties can seek arbitration to address a dispute. Part 23 pipelines are subject to information disclosure and arbitration provisions. Exempt pipelines are subject to no economic regulation. Chapter 5 outlines the various tiers of regulation.

2 The Moomba to Sydney Pipeline is subject to Part 23 regulation only from Moomba to Marsden. Light regulation applies to the remainder of the pipeline.

Note: For bi-directional pipelines, reverse capacity is shown in brackets.

Source: AER; ACCC, interim reports of gas inquiry 2017–2025; corporate websites; Gas Bulletin Board (www.gasbb.com.au).

4.8 Gas imports

In early 2021, 5 LNG import terminals projects were under consideration in NSW, Victoria and South Australia. The intention is to resolve a forecast shortfall in gas supply in the southern states from winter 2023. While some of the facilities were to be operational from as early as 2020, all projects have slipped from their original timeframes because planning, environmental and other challenges have delayed their development.

The LNG import projects include:

- Australian Industrial Energy's (AIE) proposed terminal at Port Kembla (NSW), which is the most advanced project, is scheduled to commence operating from late 2022.[27] The terminal received planning approval from the NSW Government in April 2019, and EnergyAustralia later signed as a foundation customer.[28] [29] While a final investment decision has not been formally announced, AEMO considered the project as committed in its forecasts. AIE has a long term lease with NSW Ports for the terminal's site and an agreement with Jemena to connect the terminal to the Eastern Gas Pipeline[30] [31]
- Venice Energy's proposed terminal at Port Adelaide, scheduled to launch by the end of 2022.[32] In late 2020 Venice announced it has signed its first customer, as well as advancing a project agreement with Flinders Ports for development of the facility.[33] The South Australian State Commission Assessment Panel is expected to make a decision on the development in 2021[34]
- Newcastle GasDock, proposed by Energy Projects and Infrastructure Korea, scheduled to commence operations in mid-2023.[35] The NSW Government in August 2019 designated the project as critical significant infrastructure[36]
- Viva Energy's Gas Terminal project, which is expected to deliver gas as early as 2024. The terminal would be co-located with Viva's Geelong oil refinery and is currently undergoing an environmental assessment[37]
- a potential import terminal in Port Phillip Bay in Victoria. In March 2021 Vopak announced it was considering the feasibility of the terminal.[38] As part of its announcement it indicated that several gas market participants have signed memoranda of understanding in support of the project. It anticipates submitting a proposal to the Victorian Government in the third quarter of 2021.

At April 2021 a final investment decision had not been made for any of the proposed LNG import projects.

In May 2021 AGL ceased development on its proposed floating terminal at Crib Point (Victoria).[39] This followed a determination by the Victorian Minister for Planning in March 2021 that the proposed terminal would have unacceptable environmental effects.[40] Another project backed by ExxonMobil was abandoned in December 2019.

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27 EnergyQuest, *EnergyQuarterly*, March 2021, p 27.

28 NSW Government, 'Port Kembla gas terminal approved' [media release], April 2019.

29 AIE and EnergyAustralia, 'AIE welcomes foundational customer EnergyAustralia' [media release], May 2019.

30 AIE, NSW Ports, 'Long term lease for gas terminal another key step towards supply security for NSW and economic boost for Illawarra' [media release], November 2020.

31 AIE, Jemena, 'AIE signs critical gas pipeline deal with Jemena' [media release], November 2020.

32 Venice Energy, 'South Australian LNG import facility advancing' [media release], November 2020.

33 Venice Energy, 'Project agreement signed for LNG import facility at Outer Harbor' [media release], November 2020.

34 Venice Energy, *Outer Harbor LNG project*, Venice Energy website, accessed 28 May 2021.

35 EnergyQuest, *EnergyQuarterly*, March 2021, p 29.

36 NSW Government, 'Newcastle gas terminal given critical status' [media release], August 2019.

37 Viva Energy, *Gas terminal project*, Viva Energy website, accessed 28 May 2021.

38 Vopak, 'News: Vopak LNG studies feasibility to develop LNG import terminal for Victoria' [media release], March 2021.

39 AGL Energy, 'Confirmation of Crib Point impact' [media release], May 2021.

40 Department of Environment, Land, Water and Planning (Vic), *Crib Point: AGL APA gas import jetty and Crib Point – Pakenham gas pipeline*, DELWP website, accessed 28 May 2021.

4.9 Contract and spot gas markets

Wholesale gas is traded in 2 distinct types of market. A majority of gas sales in eastern Australia are struck under confidential bilateral contracts. Around 10–20% of gas is traded in spot markets, with the variation reflecting differences between those markets.[41]

4.9.1 Contract markets

Gas contracts (also known as gas supply agreements) are wholesale supply deals negotiated between sellers and buyers. In contract markets, the 2 main levels of supply offers are:

- offers by gas producers to very large customers such as major energy retailers and gas powered generators
- offers by retailers and aggregators that buy gas from producers and onsell it to commercial and industrial (C&I) customers. Prices quoted to C&I customers tend to be higher than those quoted to very large customers, partly to cover the aggregator's margins. But the ACCC found prices to C&I customers have been unreasonably high due to a lack of competition at times (section 4.11.1).

Long term gas contracts traditionally locked in prices and other terms and conditions for several years. In recent years the industry shifted towards shorter terms for these contracts, with review provisions. In 2019 the ACCC observed the majority of recent offers for gas supply had durations of either one or 2 years.[42]

Public information about contract prices is unclear. Much of the pricing is private, and negotiated contract outcomes are often bespoke. There is also disparity between the type of information available to large participants that are frequently active in the market and that available to smaller players. This imbalance favours large incumbents in price negotiations.

Until recently, no accurate and useful indicative wholesale price was readily available to the market. In response, in 2018 the ACCC began publishing gas price data as part of its 2017–2025 gas inquiry (section 4.14.1).

4.9.2 Spot markets

While most gas is traded under confidential contracts, spot markets allow wholesale customers to trade gas without entering long term contracts. Spot market trading can be a useful mechanism for participants to manage imbalances in their contract positions.

Three separate spot markets operate in eastern Australia. The oldest of the 3 is Victoria's *declared wholesale gas market*, established in 1999. A *short term trading market* for gas was launched in 2010, with hubs in Sydney, Brisbane and Adelaide. More recently, *gas supply hubs* launched in 2014 at Wallumbilla, Queensland, and in 2016 at Moomba, South Australia. The 3 spot markets operate under different rules, follow different procedures, do not interact with each other and have different purposes (box 4.2).

In June 2017 the Australian Energy Market Commission (AEMC) found that having multiple market designs inhibits trading between regions, increases complexity and imposes transaction costs. It recommended that the markets transition in the longer term to a single market design based on the gas supply hub model.[43] As a first step, the gas day start times were harmonised for all east coast markets in 2019 (section 4.14.3). Progress towards harmonising the markets is otherwise slow.

An information platform – the Gas Bulletin Board – was launched in 2008 to provide transparency about gas market conditions and encourage participation in the spot markets. The following sections explain the workings of each spot market and the bulletin board. Section 4.11.2 outlines price trends in the markets.

41 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

42 ACCC, *Gas inquiry 2017–2020, interim report, July 2018*, August 2018, pp 24, 49.

43 AEMC, *Review of the Victorian declared wholesale gas market – final report, factsheet*, June 2017.

Box 4.2 How the different spot markets work

The gas supply hubs

The gas supply hubs take the form of a voluntary electronic platform for the 'upstream' wholesale trading of gas. Participants using the gas supply hubs can lodge trades either 'on-screen' or 'off-screen'. On-screen trades are matched anonymously through the hubs' electronic trading platform. Each price struck is unique to a particular trade – that is, no market clearing price applies to all participants. Off-screen trades are agreed to by participants bilaterally and then lodged through the hub for settlement. Purely bilateral 'off-market' trades are not reported.

There are 5 standard product lengths that participants can use when trading at the gas supply hubs: balance of day, daily, day ahead, weekly and monthly. As in the other spot markets, the gas supply hubs complement bilateral contracts rather than replace them. But participants can trade gas up to a year in advance of physical supply rather than only on a daily basis as in the other markets.

A significant proportion of trade occurs off-screen, which allows participants to use brokers to match trades on their behalf or leverage their existing bilateral arrangements to facilitate spot trades.[44] Such trades can be negotiated directly over the phone and then lodged through the hubs for settlement, which can be faster if on-screen bids and offers do not match. However, new entrant participants are unable to enjoy these benefits to the same degree, because they do not have legacy arrangements. These participants are more likely to rely on the anonymous on-screen trading platform.

The short term trading markets

The short term trading market allows gas trading on a day-ahead basis. The Australian Energy Market Operator (AEMO) sets a day-ahead clearing price at each hub based on scheduled withdrawals and offers by shippers to deliver gas, with a price floor of $0 per gigajoule (GJ) and a cap of $400 per GJ. All gas supplied according to the schedule is settled at this price. The market provides incentives for participants to keep to their schedules, and the rules oblige participants to bid in 'good faith'. Pipeline operators schedule flows to supply the necessary quantities of gas to each hub. As gas requirements become better known closer to the time of delivery, shippers may renominate quantities with pipeline operators (depending on the terms of their contracts).

If gas deliveries and/or withdrawals from a hub do not match the day-ahead nominations then AEMO procures balancing gas – called market operator services (MOS) – to meet any shortfalls. Conversely, it procures storage on transmission pipelines with capacity to manage an oversupply. Participants make offers to supply MOS, which AEMO calls on in order of lowest to highest price when balancing gas is needed. The parties causing the imbalances mainly pay for the gas procured under this mechanism. The Australian Energy Regulator (AER) has reported instances of abnormally high MOS payments in parts of the market, resulting in some investigations.[45]

Generally, prices in the short term trading markets are volatile, reflecting short term shifts in supply and demand, including conditions in liquefied natural gas (LNG) export markets. Given its responsiveness to short term conditions, the markets are not necessarily indicative of prices that would be struck under contracts. No Australian Securities Exchange derivatives market has developed for the short term trading markets.

The Victorian declared wholesale gas market

The Victorian declared wholesale gas market manages gas flows across the Victorian transmission system. Participants submit daily bids ranging from $0 per GJ (the floor price) to $800 per GJ (the price cap). At the beginning of each day, AEMO selects the least cost bids needed to match demand. This process establishes a clearing price. In common with the short term trading markets, only net positions are traded.

The Victorian market differs from the short term trading market in a number of ways. 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 and can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term transmission constraints. Also, the short term trading market is for gas only, while prices in the Victorian market cover gas as well as transmission pipeline delivery.

44 AER market intelligence.

45 AER, *State of the energy market 2017*, 2018, p 76.

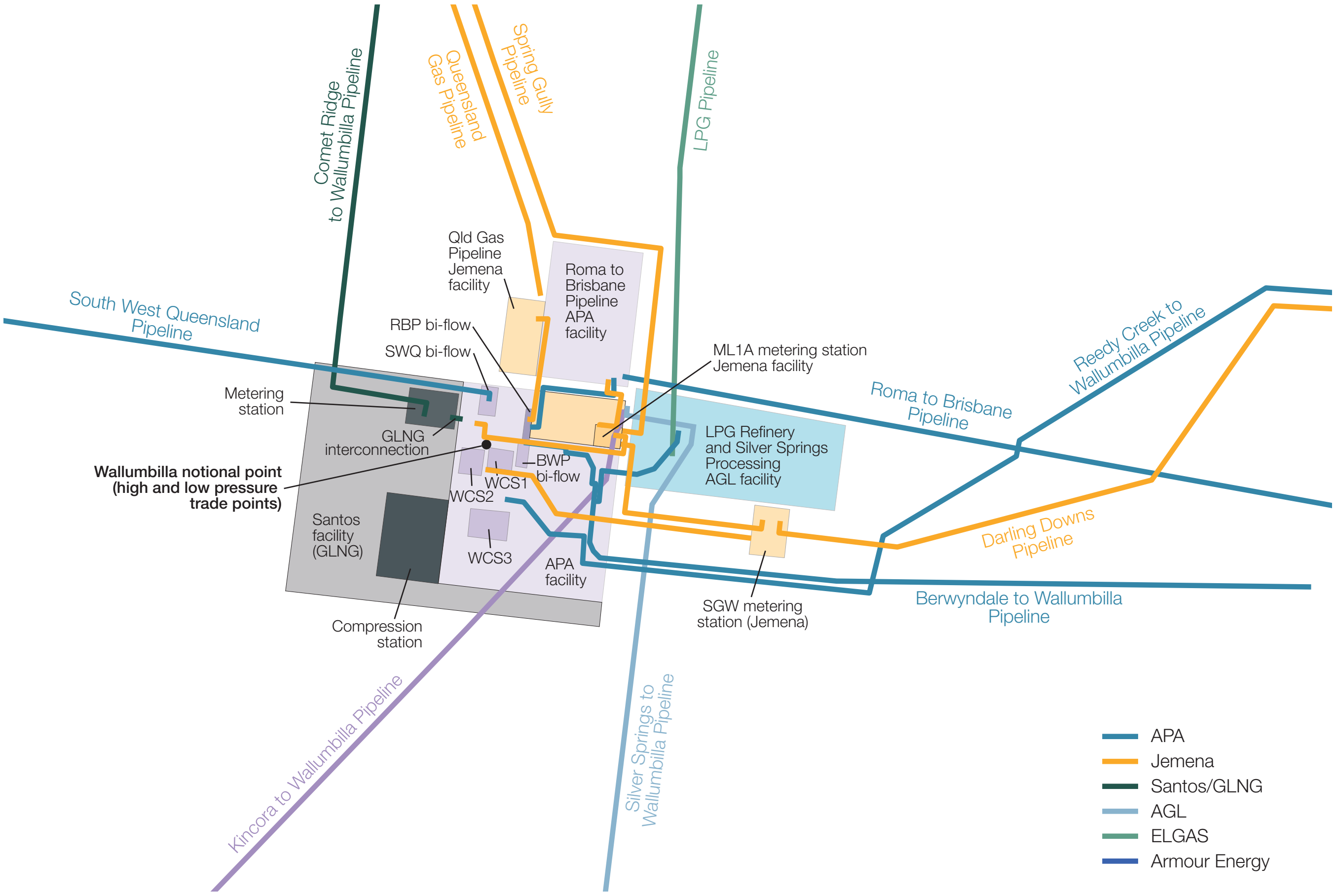
4.9.3 Gas supply hubs at Wallumbilla and Moomba

AEMO launched the gas supply hub model at Wallumbilla, Queensland, in 2014. Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia, making it a natural point of trade (figure 4.7).

Until 2017 at the Wallumbilla hub, separate prices were set at 3 major delivery points – the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines. But splitting trade across 3 locations hampered liquidity and trading. Additionally, participants needed access to the transmission pipelines serving the hub, to move gas between those 3 points. This access proved problematic because, while all the pipelines connect with the hub, they do not all physically interconnect with one another.

In March 2017 AEMO replaced the Wallumbilla hub's 3 trading locations with a single Wallumbilla product that groups all delivery points. A single trading location improves liquidity by making it easier for participants to trade across different pipelines, thus pooling potential buyers and sellers into a single market. A separate south east Queensland product was also launched, which provides virtual delivery within the Roma to Brisbane Pipeline.

Figure 4.7 Wallumbilla hub



Source: AER, accounting for consultations with APA Group and public information supplied by APA Group, Santos, AGL, the Queensland Government, Geoscience Australia and AEMO.

Separately, AEMO launched a second gas supply hub at Moomba in central Australia in June 2016. Similar to Wallumbilla, Moomba is a major junction in the gas supply chain serving eastern Australia. Three critical pipelines – the South West Queensland, Moomba to Sydney, and Moomba to Adelaide pipelines – connect to the hub, along with several smaller pipelines and storage facilities. The Moomba hub uses the same model as the Wallumbilla hub, with trade taking place at a central Moomba location.

In 2020, 19 participants traded at the gas supply hubs, of which 17 were active, including 4 new participants.[46] LNG export businesses and gas producers were among the most active participants in 2020. LNG producers are large suppliers of gas into the hubs, although operational issues can limit their participation. In addition, the physical interconnection of LNG facilities allows them to trade easily among themselves. Some market participants have suggested the scale of the LNG producers' operations may involve greater volumes than the hubs can currently

46 We consider a participant 'active' if it makes at least 12 trades in a year.

absorb.[47] Other participants include large retailers, gas powered generators, large industrial users and traders. Activity by traders (including brokers and investors) rose to 20% on average in 2020, up from 12% in 2019.[48]

In 2020, 18 participants traded on-screen, but only 15 traded actively. Similarly, 18 participants traded off-screen, but only 15 were active. On average, participants executed around 220 trades per month in 2020 – a reduction of 27% from 2019 levels.

Wallumbilla hub activity

Trade at Wallumbilla increased progressively since its launch in 2014 but has reduced more recently. The LNG projects use the hub from time to time to manage variations in production and LNG plant performance. Gas powered generators are also significant users of the hub. Most recently, trader participants have increased their activity, taking advantage of the day-ahead auction to arbitrage prices between Wallumbilla and the downstream markets.

In 2020 liquidity at the Wallumbilla hub reduced following significant growth and change in previous years. Traded volumes for 2020 fell from the highs in 2019, primarily due to a collapse in on-screen trading, but remained higher than 2018 levels for all products (figure 4.8). Notably, off-screen products tend to involve larger volumes of gas than do on-screen alternatives. There was also a shift in product preferences in 2020, with most gas traded in daily and monthly products, compared to 2019, where most gas was traded in day-ahead and balance of day products.

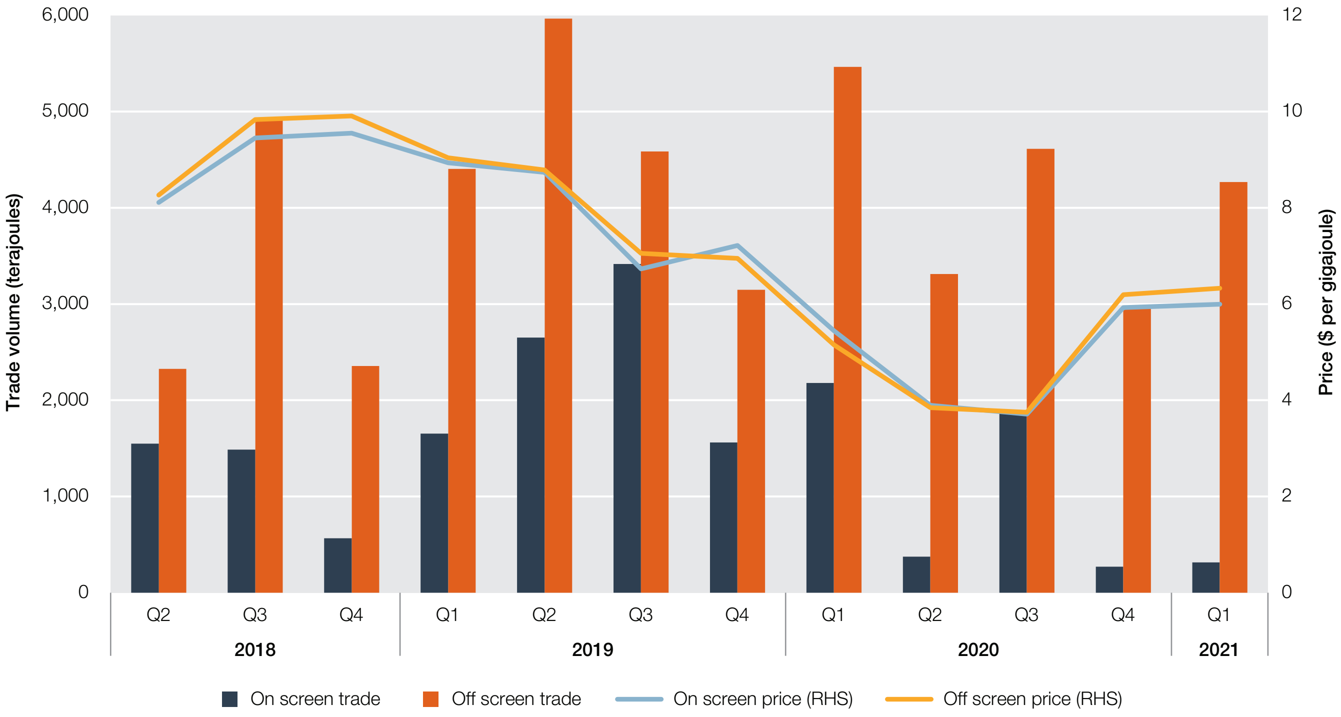
Ultimately, however, gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral, off-market arrangements. In 2020 gas traded through the Wallumbilla hub accounted for 6.8% of total gas flows through pipelines in the Wallumbilla bulletin board zone.[49]

Moomba hub activity

Trade at Moomba has been slow to develop. While there have been offers and bids for gas at Moomba, fewer transactions have occurred there compared with Wallumbilla.

The first trade was executed in September 2017, with 141 trades executed in 2019. Similar to Wallumbilla, trades at the Moomba location decreased significantly in 2020.

Figure 4.8 Gas supply hub – on-screen and off-screen price and volume



Source: AER analysis of gas supply hub data.

47 AER market intelligence.

48 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

49 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

4.9.4 Short term trading market

In 2020 around 30 participants traded in the Sydney short term trading market (STTM), while the Adelaide and Brisbane markets each had around 20 participants. The participants included energy retailers, power generators, large industrial gas users, and traders. The markets are particularly useful for gas powered generators, because the generators can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

Shippers deliver gas for sale into the market, and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users but in effect trade only their net positions – that is, the difference between their scheduled gas deliveries into and out of the market. In the fourth quarter of 2020, gas traded through the STTM met nearly 25% of demand in Sydney, more than 22% in Adelaide and around 8% in Brisbane.[50]

Traded volumes at the Sydney market were 25% higher in 2020 than in 2019, 53% higher at the Brisbane market and 19% higher at the Adelaide market. This increased spot trade has been supported by higher sales volumes from large gas producers, including LNG exporters, with Santos and BHP prominent sellers across 2020. Increased gas availability was due to a combination of excess supply from high production levels in Queensland and generally lower LNG exports in the middle of the year.

Trading profiles varied across the markets. Concentration across the top 3 sellers fell in Brisbane and Adelaide from 2019 to 2020 but rose in Sydney (figure 4.9). Among the top 3 buyers, concentration increased in Brisbane, fell in Adelaide and remained steady in Sydney market for the same period. Importantly, the diversity of large suppliers participating in the spot markets is increasing. Similarly, in 2020, trader participants increased their share of gas scheduled into the STTMs to record levels. These participants took advantage of cheap capacity won on the day-ahead auction to arbitrage prices between markets.

In 2018 the ACCC reported evidence of C&I customers engaging more heavily in the STTM to manage their gas supply, with some users switching to the market to cover their entire demand. This trend has continued. In 2020 the AER reported that participants are using the STTM more heavily, with industrial participants being prominent gas purchasers.[51] This is reflected in new registrations, with more new industrial users registering to participate in the domestic markets than any other participant type since 2018.

Sourcing gas from the spot markets can be to those users' benefit. For example, between late 2019 and mid-2020, spot prices ranged between $4.50 per gigajoule (GJ) and $6 per GJ. Over the same period contract offers for gas delivery in 2020 and 2021 were between $8 per GJ and $11 per GJ.[52] In addition, collective buyer groups have emerged, which improves the purchasing power of the constituent members and helps secure better deals for both spot and contract purchases.

4.9.5 Victoria's declared gas market

Over 30 participants traded in the Victorian market in 2020, including energy retailers, power generators and other large gas users, and traders. From 2019 to 2020, while trading concentration among the top 3 buyers fell slightly, concentration among the top 3 sellers rose significantly from 39% to 54% (figure 4.9). Despite this increased concentration, there is evidence of improving competition between participants driving lower prices in Victoria.[53]

Like the STTMs, volumes traded in the Victorian market rose in 2020, although more modestly (up 2%), after a more significant increase the previous year. Since mid-2019 there has been a consistent increase in quarterly flows of gas into Victoria through the Culcairn injection point. The majority of this is by operators of gas powered generation, but other participants have been increasing their deliveries recently, facilitated by the day-ahead auction.

A small futures market has developed for the Victorian market, with the ASX launching a Victorian gas future product in 2013. But there was little trade until mid-2018. Since the start of 2019, activity and trade volumes have increased and remained consistent. Ultimately this increase still accounts for only a small proportion (around 5% or less) of the total volume traded in the market. However, increasing levels of open interest and increased spot trading in short term markets are encouraging signs.

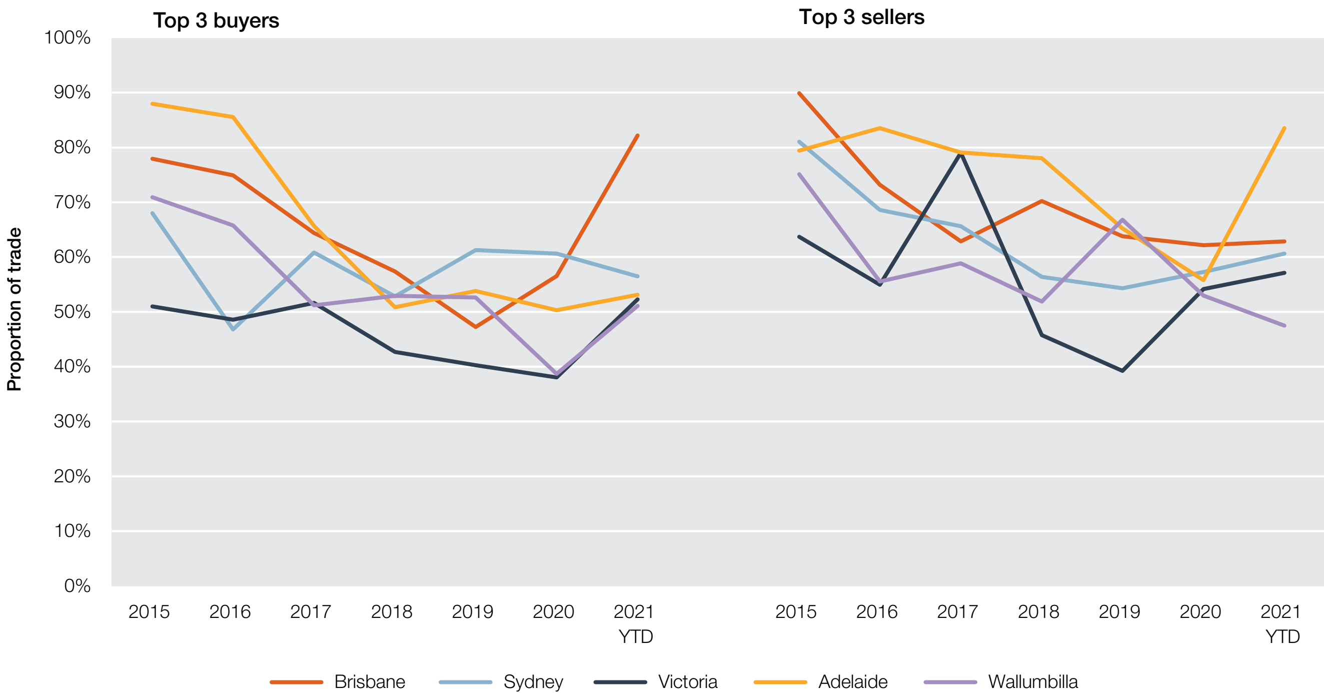
50 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

51 AER, *Wholesale markets quarterly – Q3 2020*, November 2020.

52 AER, *Wholesale markets quarterly – Q3 2020*, November 2020.

53 AER, *Wholesale markets quarterly – Q3 2020*, November 2020.

Figure 4.9 Top 3 buyers and sellers in eastern Australian gas markets



Source: AER analysis of data from the gas supply hub, short term trading market and Victorian declared wholesale gas market.

4.9.6 Gas Bulletin Board

The Gas Bulletin Board (www.gasbb.com.au) is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. Market participants – gas producers, pipeline businesses and storage providers – supply the information to AEMO, which then publishes it. The AER monitors participants' compliance with their obligations to submit accurate data, and enforces compliance.

The bulletin board plays an important role in making the gas market more transparent, especially for smaller players who may not otherwise be able to access day-to-day information on demand and supply conditions. It supplies information such as:

- pipeline capabilities (maximum daily flow quantities, including bi-directional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities
- daily production capabilities and capacity outlooks for production facilities
- gas stored, gas storage capacity (maximum daily withdrawal and holding capacities), and actual injections/withdrawals.

The bulletin board includes an interactive map showing gas plant capacity and production data; and gas pipeline capacity and flow at any point in a network.

The bulletin board's coverage has progressively widened. Significant reforms in 2018 removed reporting exemptions, mandated greater detail for covered facilities and lowered the reporting threshold to encompass smaller facilities (section 4.14.1). To encourage compliance, the reforms made reporting obligations subject to civil penalties. Reporting obligations were also extended to gas facility operators in the Northern Territory, following the territory's connection to the eastern gas grid in January 2019. Additional reforms are currently under consideration to expand the scope of information reported (section 4.14.1).

4.10 State of the eastern gas market

The development of Queensland's LNG export industry placed significant pressure on the eastern gas market. The pressure, combined with other factors such as state-based moratoriums on gas development, tightened the supply–demand balance. This tightening led to increases in wholesale gas prices from 2017 as international gas prices began to bear on domestic gas prices. However, these price pressures eased over 2020 as international gas prices fell. Also, reforms introduced in 2019 to improve access to critical pipelines allowed a wider range of participants to access cheap transportation, contributing to lower wholesale gas prices in 2020.

Despite COVID-19 dampening LNG exports in the middle of the year, gas production in the northern states again rose to record levels in the fourth quarter of 2020. In the same quarter LNG export demand rebounded, as a spike in international prices drove exports to record levels. This did not have a significant impact on the domestic markets, however, as domestic demand declined and excess gas flowed north to meet demand. The day-ahead auction supported participants' flexibility in responding to prevailing conditions.

4.10.1 Supply conditions

While a majority of eastern Australia's gas reserves are located in Queensland's Surat–Bowen Basin, those reserves are largely committed to the LNG export industry. Each year since 2013, gas production in Queensland has reached record levels. In 2020 production increased again to nearly 4,075 TJ per day as LNG projects ramped up production, particularly in the fourth quarter, to meet record export demand.

Queensland's LNG projects originally planned to source their gas requirements from their own (newly developed) reserves in the Surat–Bowen Basin. But the development of gas wells by Santos's GLNG project was slower than expected. To meet its LNG supply contracts, therefore, Santos sourced substantial volumes of gas from other producers, diverting gas from the domestic market.

The tightening supply–demand balance following the commencement of LNG exports led to concerns in 2017 that gas production may not be sufficient to meet domestic demand. In response, the Australian Government threatened to instruct LNG producers to supply more gas to the domestic market. The Australian Domestic Gas Security Mechanism empowers the Energy Minister to require LNG projects to limit exports or find offsetting sources of new gas if a supply shortfall is likely (section 4.13.2).

To avoid export controls, Queensland's LNG producers have entered a series of heads of agreement with the Australian Government since October 2017, with the most recent agreement in December 2020.[54] Under the agreements, they commit to offer uncontracted gas to domestic buyers on competitive terms before offering it for export.

The LNG projects use various methods to sell more gas domestically, including selling short term gas on the Wallumbilla gas supply hub; launching expression of interest (EOI) processes for customers for long term gas contracts; and entering bilateral arrangements for short term and long term gas contracts. In 2019, for example, APLNG entered new supply agreements with gas powered generators and other large domestic customers.[55]

In 2021 AEMO forecast an improved gas supply outlook compared to previous years. This improved outlook reflected progress in the planning for AIE's Port Kembla LNG import terminal. While a final investment decision is still forthcoming, the project appears committed and is estimated to be capable of delivering up to 500 TJ per day into the southern region. If the project is commissioned ahead of winter 2023, alongside other committed field development and pipeline expansions, AEMO forecast that the additional supply will be sufficient to offset significant reductions in Victorian production.

Despite improved supply forecasts in the short run, the longer term outlook is uncertain. AEMO forecast that, even with the addition of the Port Kembla import terminal, supply gaps could emerge by 2026.[56] Similarly, the ACCC reported a broader shortfall in supply from 2P reserves could emerge by 2026.[57] Both AEMO and the ACCC suggested more exploration and development in southern Australia, pipeline expansions and LNG imports could mitigate the supply risks.

54 Department of Industry, Science, Energy and Resources, *Securing Australian domestic gas supply*, DISER website, accessed 28 May 2021.

55 Australia Pacific LNG, 'Australia Pacific LNG delivers new gas supplies to domestic manufacturers' [media release], 4 July 2019; Australia Pacific LNG, 'Australia Pacific LNG continues strong support of domestic gas market' [media release], 26 September 2019.

56 AEMO, *2021 gas statement of opportunities*, March 2021, p 5.

57 ACCC, *Gas inquiry 2017–2020, interim report, January 2021*, February 2021.

Long term supply conditions are uncertain for a number of reasons. First, some developed resources may underperform, and southern production may decline faster than expected. Second, forecasts make assumptions about undeveloped gas fields with uncertain reserves. These assumptions are increasingly unreliable, as the long term security of supply for the east coast increasingly depends on more speculative sources of supply – that is, 75% of 2C resources in early 2020 were located in fields that were not yet in production or approved for development, and some 2P reserves and resources in Queensland have been written down.[58] [59] While some development proposals in eastern Australia show promising signs, others face significant regulatory hurdles linked to environmental concerns.

In response to this ongoing supply uncertainty, the Australian Government and some state governments launched initiatives to encourage new projects to supply the domestic market (section 4.13).

Supply conditions in the northern region

Gas supply to the northern gas market is largely supplied from Queensland's Surat–Bowen Basin. But gas is also sourced from the Cooper Basin in South Australia and, since 2019, from the Northern Territory (via the Northern Gas Pipeline). At times, southern gas is also transported north to meet LNG export demand.

Gas production in the Surat–Bowen Basin rose exponentially from 2014 to 2017 to meet the demands of Queensland's LNG export industry. While production has continued to rise since 2017, the year on year growth was less dramatic and has levelled out now all LNG projects have reached full operation.

Despite this levelling out, northern production in 2020 rose to record levels of almost 4,500 TJ per day. In the fourth quarter of 2020, Queensland facilities produced a record 4,240 TJ of gas per day – a slight increase from the previous record of 4,126 TJ per day in the fourth quarter of 2019. This record production coincided with record levels of LNG exports in the fourth quarter of 2020 as Asian LNG prices spiked, despite generally low international gas and oil prices across the year.[60]

Supply conditions also depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, pipeline operators are considering a range of upgrades to extend or expand existing infrastructure. For example, in 2020 APA announced that it was investigating adding compression to both the South West Queensland Pipeline and Moomba to Sydney Pipeline to increase delivery capacity from northern fields to southern markets.[61]

New entry

Across 2020 the number of suppliers in the eastern market rose, and some producers expanded their presence in downstream markets.[62] Also, the growth of traders participating in eastern Australian gas markets disrupted dominant players and provided C&I customers with competitive alternative sources of gas.

Five new projects are expected to commence operations in Queensland over the next 4 years. The operators of these projects include Arrow Energy, Denison Gas and QGC.[63] As a result, supply options to C&I gas users appear to be improving.

Supply conditions in the southern region

Historically, the Victorian gas basins and the Cooper Basin in central Australia were pivotal to meeting domestic gas demand in southern Australia. Since 2018 gas from the northern fields has been required to supplement Victorian gas production and balance southern gas demand.

Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce. After achieving record production levels in 2017, production from the Longford plant, servicing the Gippsland Basin, fell. The plant is becoming less reliable because it is run harder for longer, and plant constraints and maintenance outages increasingly disrupt production.

58 2C resources represent the best estimate of contingent gas reserves, which are not yet technically or commercially recoverable.

59 Queensland reserves were downgraded (on a net basis) by more than 4,400 PJ between 1 July 2017 and 30 June 2019. See ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, February 2020.

60 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

61 APA, 'APA response to 2020 GSOO' [media release], May 2020.

62 AER, *Wholesale markets quarterly – Q3 2020, November 2020*.

63 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 39.

In 2021 AEMO reported the anticipated decline in production in key southern fields had accelerated, with the fields expected to deplete by winter 2023.[64] The depletion of these fields will place greater pressure on the southern markets and reduce peak day supply capacity. But new projects are expected to be address this supply concern.

Cooper Energy's Sole project in the Gippsland Basin began commercial operation in March 2020. The project is the first new production well drilled in offshore Victoria since 2012, and it can produce up to 25 PJ per year. However, production from this field has been impacted by problems at the Orbost gas plant.[65] Another project, the West Barracouta joint venture between Esso Australia and BHP Billiton, is scheduled to be operational in 2021.

Production from these new projects is likely to be supported by new supply from AIE's planned 500 TJ per day Port Kembla LNG import terminal. While other import terminal projects exist, Port Kembla appears to be the most progressed. With commitments the terminal will be operational ahead of winter 2023, AEMO deferred previously forecast supply shortfalls to at least 2026. As part of planning for the Port Kembla LNG import terminal, Jemena is proposing an extension and upgrade to the Eastern Gas Pipeline. This project would connect the terminal to the eastern Australian gas markets and allow delivery of significant gas volumes into both NSW and Victoria.[66] Jemena is also considering extending the pipeline into the Hunter Valley to support proposed gas powered generation in the region.[67]

Regulatory barriers to gas development

In some states and territories, community concerns about environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development.[68] Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- In 2017 the Victorian Government banned onshore hydraulic fracking and exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[69] In March 2021 the government committed the ban on fracking and CSG exploration to the Victorian Constitution.[70] Onshore conventional gas exploration will recommence from July 2021.
- In 2018 South Australia introduced a 10-year moratorium on fracking in the state's south east. It introduced the moratorium by direction and announced its intention to legislate it. However, unconventional gas extraction is allowed in the Cooper and Eromanga basins. South Australia has no restrictions on onshore conventional gas.
- In 2015 the Tasmanian Government banned fracking for the purpose of extracting hydrocarbon resources (including shale gas and petroleum) until March 2020. This has since been extended to 2025.[71]
- In 2018 the Northern Territory made 51% of the territory eligible for hydraulic fracturing. The decision covers much of the Beetaloo Basin, which holds most of the territory's shale gas resources.

Queensland does not restrict fracking. NSW has no outright ban on onshore exploration, but significant regulatory hurdles have stalled development proposals. Regulatory restrictions include exclusion zones, a gateway process to protect 'biophysical strategic agricultural land', an extensive aquifer interference policy, and a ban on certain chemicals and evaporation ponds.[72] The state's regulations also require community consultation on environmental impact statements; and a detailed review process for major projects, as highlighted by the protracted process for Santos's Narrabri gas project.[73] Under an agreement reached in early 2020, the NSW and Australian governments set a target of increasing supply to the NSW market by 70 PJ per year.[74]

64 AEMO, *2021 Victorian gas planning report*, March 2021.

65 EnergyQuest, *EnergyQuarterly*, March 2021.

66 Jemena, 'More gas for Victoria by 2023' [media release], March 2021.

67 Jemena, 'Jemena reveals plans to extend Eastern Gas Pipeline' [media release], September 2020.

68 Hydraulic fracturing, also known as fracking, is a process that involves injecting a mixture of water, sand and chemicals at high pressure into underground rocks to release trapped pockets of oil or gas. A well is drilled to the depth of the gas or oil bearing formation, then horizontally through the rock. The fracturing fluid is then injected into the well at extremely high pressure, forcing open existing cracks in the rocks, causing them to fracture and breaking open small pockets that contain oil or gas. The sand carried by the fluid keeps the fractures open once the fluid is depressurised, allowing oil or gas to seep out.

69 Department of Economic Development, Jobs, Transport and Resources (Victoria), Onshore gas community information, August 2017.

70 Victorian Government, 'Enshrining Victoria's ban on fracking forever' [media release], March 2021.

71 Department of State Growth (Tas), *Tasmanian Government policy on hydraulic fracturing (fracking) 2018*, DSG website, accessed 28 May 2021.

72 Department of Planning and Environment (NSW), Initiatives overview, July 2018.

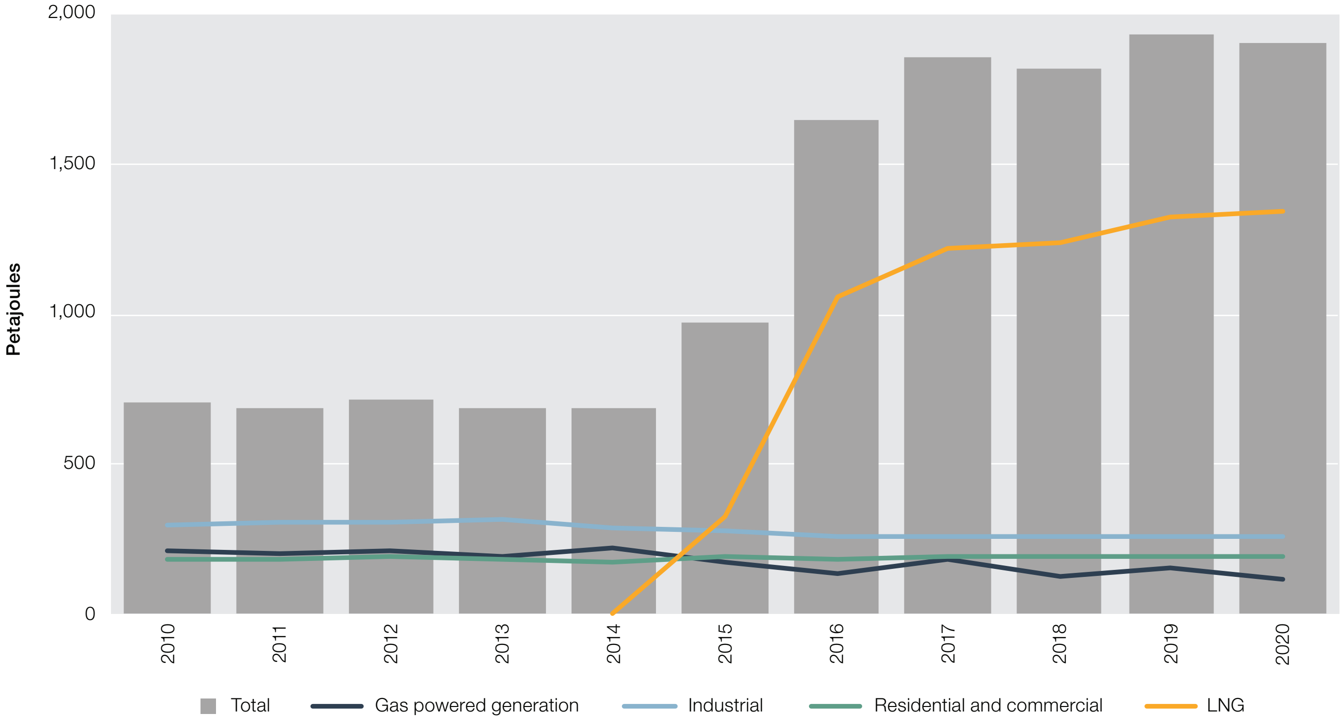
73 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed' [media release], 7 June 2017.

74 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions' [media release], January 2020.

4.10.2 Demand conditions

Historically, demand for eastern Australian gas derives from 3 main domestic sources – C&I gas users, gas powered generators and residential customers. However, with the launch of LNG exports in 2015, international customers became a new source of demand competing to buy eastern Australian gas (figure 4.10).

Figure 4.10 Eastern Australian gas demand



Source: AEMO, 2021 gas statement of opportunities, March 2021.

Domestic gas use

Higher gas prices have weakened gas demand by industrial customers since 2014. Despite this trend, industrial demand remained relatively steady across 2020, supported by easing prices. The COVID-19 pandemic did not appear to have a significant effect on demand from industrial customers.[75] However, the impact of COVID-19 on other areas of these users' businesses may lead to heightened sensitivity regarding future gas prices and affect consumption.

Despite improving conditions over 2020, longer term concerns still exist and participants are exploring strategies to manage the risk of high prices, including forming buyers groups and using brokers to secure favourable contract arrangements.

Among domestic sources of demand, gas powered generation is the most volatile (figure 4.11). Gas is a relatively expensive fuel for electricity generation, so gas generators typically operate as 'flexible' or 'peaking' plants that can be switched on at short notice to capture high prices in the electricity market. Gas demand for power generation, therefore, tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are higher. It also varies with the amount of renewable generation available (which is cheap but weather dependent).[76] Gas generation is forecast to play an increasingly important role over winter when solar photovoltaic generation is lower and coal fired capacity may be withdrawn for maintenance.[77]

Rising gas fuel costs linked to Queensland's LNG industry, along with a shortage of gas supplies linked to state-based moratoriums on gas exploration and production, stalled demand for gas powered generation in the state from 2015 to 2019. Gas powered generation slumped from 17% of Queensland's electricity output in 2015 to 8% in 2020. A similar squeezing-off occurred in NSW.

75 ACCC, *Gas inquiry – January 2021 interim report*, January 2021.

76 EnergyQuest found a –89% correlation between gas and hydroelectric generation; and a –48% correlation between gas and wind generation over 42 months to June 2018. See EnergyQuest, *EnergyQuarterly*, September 2018, p 35.

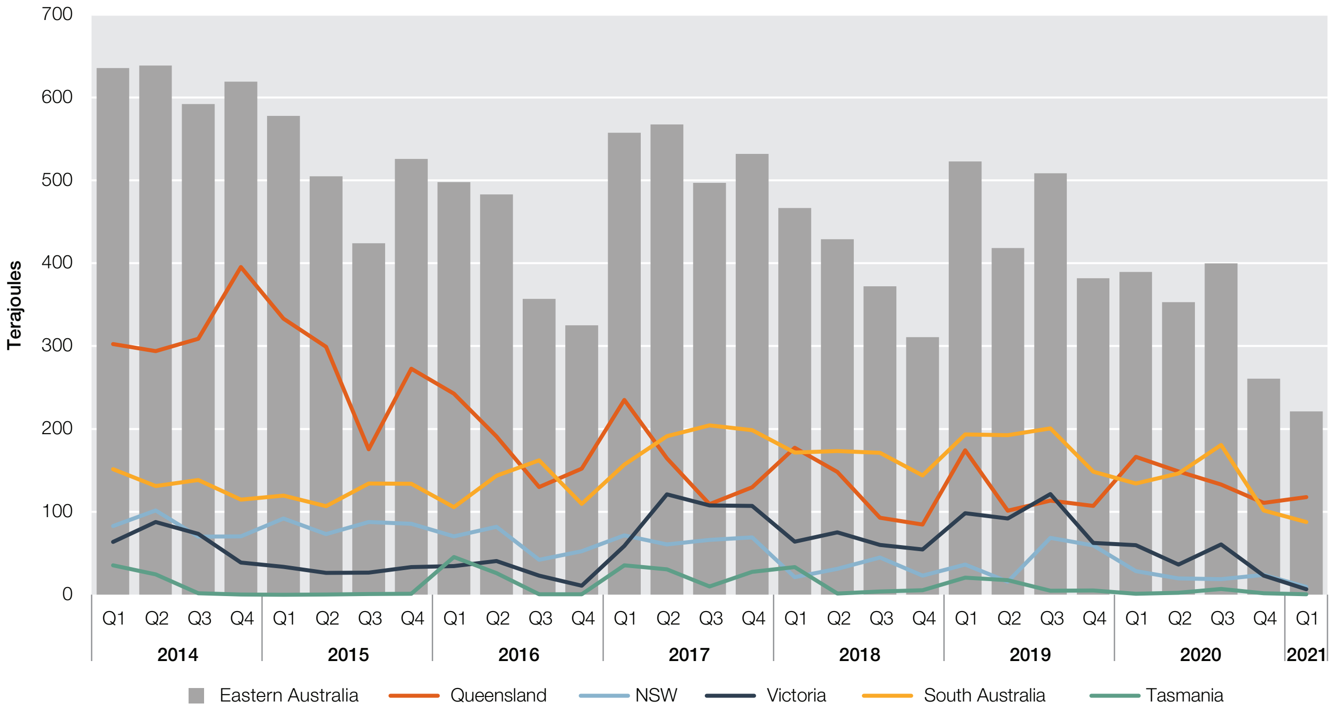
77 AEMO, *Gas statement of opportunities 2021*, p 37.

Different conditions prevailed in Victoria and South Australia, where coal generation retirements and rising outages among remaining plant made gas generation critical to meeting electricity demand. In particular, when Hazelwood power station closed in 2017, gas powered generation rose in both states. As a result, demand for gas powered generation rose across 2017 to 2019.

In 2020 gas powered generation fell in all southern regions due to constrained demand and low electricity prices. Gas powered generation fell from 3% to 2% of electricity generation in NSW, 7% to 3% in Victoria, and 48% to 41% in South Australia. The reduced generation South Australia coincided with the closure of 2 units at the Torrens Island A power station in September 2020. While gas generators offered more capacity in Victoria, it was priced at higher levels so was dispatched less. Over the same period, gas powered generation increased from 8% to 10% of all electricity generation in Queensland as a result of greater generation at Swanbank E power station. This reflected a change in operation of the plant following its transfer to CleanCo.

Gas used for gas powered generation continued to decline in the first quarter of 2021, recording the lowest quarterly level since 2006.[78] However, AEMO expects gas powered generation to fill an electricity supply gap across 2021 caused by higher coal generator outages.[79]

Figure 4.11 Quarterly gas demand for gas powered generation



Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

Liquefied natural gas exports

LNG exports continue to grow, with record volumes over 2020 (and a record quarterly volume in the fourth quarter of 2020) contributing to Australia remaining the world's largest exporter of LNG.[80] Both APLNG and QCLNG projects operated at or above capacity in 2020, contributing to record eastern Australian production levels (figure 4.12).

China is the primary market for eastern Australian LNG, accounting for 67% of exports in 2020 (815 PJ). Chinese exports were 6% lower than the previous year's volume, marking the first year that Chinese demand decreased since LNG exports commenced. Despite this reduction, China's LNG demand is expected to continue to grow, supported by expanded industrial and residential gas use.[81]

78 AER, *Wholesale markets quarterly Q1 2021*, May 2021.

79 AEMO, *Gas statement of opportunities*, March 2021, p 37.

80 EnergyQuest, *EnergyQuarterly*, March 2021.

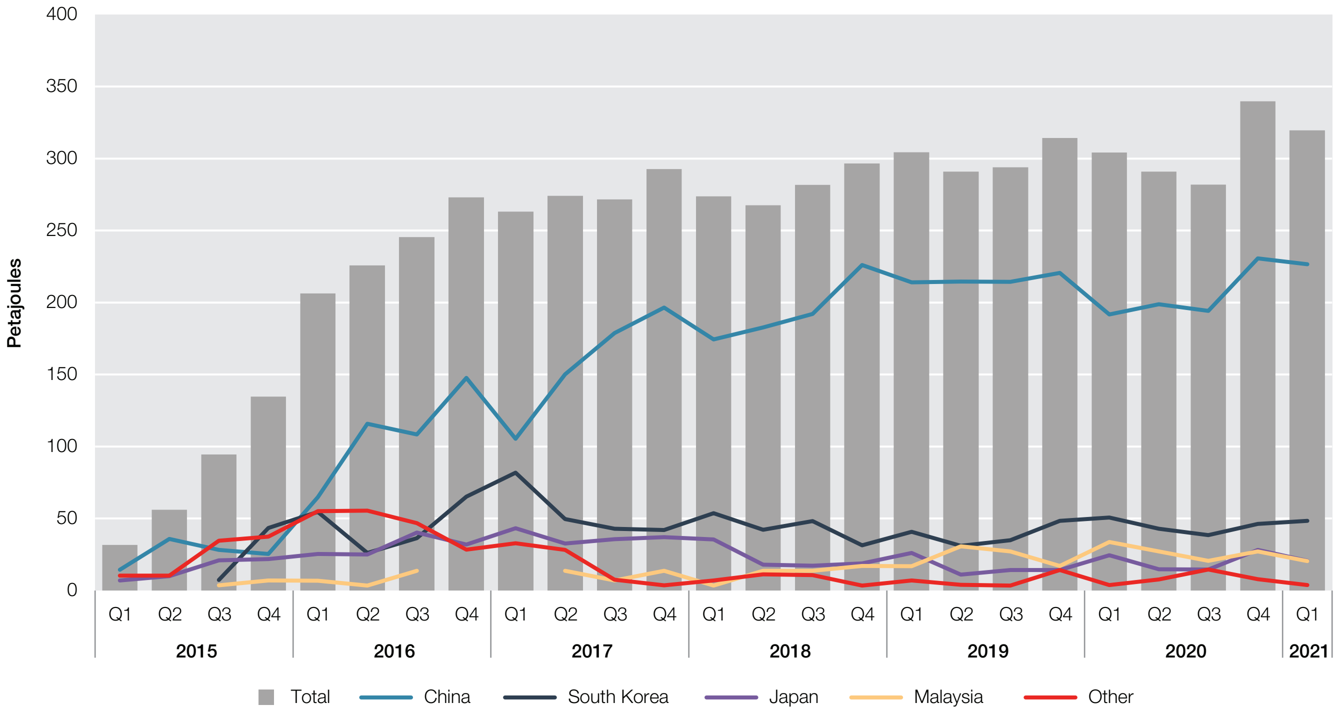
81 Department of Industry, Science, Energy and Resources, *Resources and energy quarterly*, December 2020.

The other main sources of demand for eastern Australian LNG increased in 2020, offsetting the decrease in Chinese demand. Japan's demand grew by 26% in 2020 to 82 PJ and South Korean demand rose by 15% to 178 PJ. Government policies restricting coal fired generation may buoy gas demand in South Korea over the coming decade, but greater use of nuclear reactors for electricity generation will likely reduce longer term gas demand from both Japan and South Korea. Malaysian demand for LNG also increased 17% in 2020 to 108 PJ.

Strong demand caused a surge in LNG spot prices from mid-2017. Monthly Asian spot prices reached around $14 per GJ in December 2017 and remained elevated throughout 2018. But new LNG capacity in the United States, Australia and Russia came online in 2019, creating an oversupply and driving prices lower.

A slowing Chinese economy, Japan's ongoing switch away from gas powered generation, and further increases in US export capacity kept downward pressure on prices in late 2019 and early 2020. Also in early 2020 the outbreak of COVID-19 contributed to reduced Asian LNG demand and weaker spot LNG and oil prices.[82] This price downturn coincided with intense price competition among oil exporting countries. Australian exporters reported that the uncertainty stemming from COVID-19 and collapsing oil prices limited their ability to strike new gas supply agreements and finalise investment decisions.[83]

Figure 4.12 Eastern Australian gas exports



Source: Gladstone Ports Corporation; trade statistics.

The COVID-19 pandemic resulted in changes to supply–demand profiles, project deferrals and asset sales; and sustained downward pressure on prices. Despite this, the eastern Australia LNG industry remained resilient. As LNG export flows decreased, producers seized the opportunity to conduct maintenance and divert flows into storage facilities.

Late in 2020 Asian LNG demand rebounded during the northern hemisphere winter. From December 2020 to January 2021 a cold snap created unexpectedly strong LNG demand in Asia, leading to high international prices. This also coincided with coal supply issues in China, and congestion at the Panama Canal, which caused delays in cargoes reaching Asia from further afield. This drove record eastern Australian LNG exports in 2020.

This volatility was short lived, however. By mid-January 2021 Asian LNG prices returned to levels similar to before the spike. Eastern Australian LNG exports fell slightly in the first quarter of 2021, but remained at high levels buoyed by continued winter heating and generation needs and robust industrial demand.

82 AER, *Wholesale markets quarterly – Q1 2020*, May 2020.

83 AER, *Wholesale markets quarterly – Q1 2020*, May 2020.

4.10.3 Inter-regional gas trade

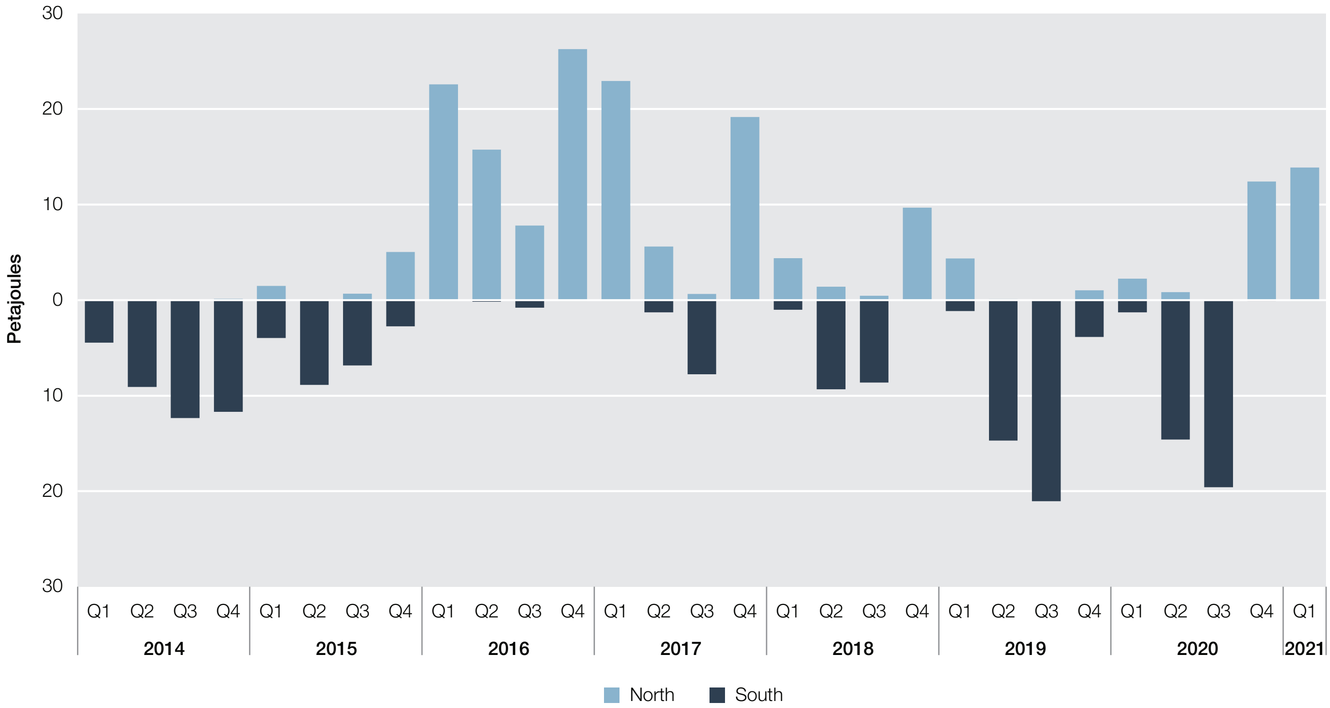
A signature feature of the domestic gas market since 2014 is the role of inter-regional gas trades to manage the supply–demand balance. Key pipelines have been re-engineered as bi-directional, enabling them to respond more flexibly to regional supply and demand conditions.

With the launch of Queensland's LNG projects in 2015, the projects began drawing substantial volumes of gas from Victoria and South Australia to cover shortfalls in their reserve portfolios. Conditions in the domestic electricity market also affect trade flows. Following the closure of coal fired generators in the southern states, increased demand for gas powered generation in those states drew gas south, especially during the Australian winter, when heating demand peaks. In recent years, gas flows turn southbound even before the onset of winter.

The threat of government intervention in the gas market (section 4.13) also impacted flows from late 2017. To avoid triggering intervention, Queensland's LNG producers began offering more gas to the domestic market, which increased southbound trade flows. Exporters committed to the Australian Government to first offer any uncontracted gas to the domestic market on a competitive basis.

Following these events, flows settled into a cycle of gas flowing south in the Australian winter (to meet heating demand) and north in the Australian summer (the northern hemisphere winter) when Asia's LNG demand peaks (figure 4.13).

Figure 4.13 North–south gas flows in eastern Australia



MSP: Moomba to Sydney Pipeline; QSN: Queensland / South Australia / New South Wales; SWQP: South West Queensland Pipeline.

Note: Flows on the QSN Link section of the South West Queensland Pipeline. Northbound flows are from the southern states into Queensland. Southbound flows are exports from Queensland to the southern states.

Source: AER analysis of Gas Bulletin Board data.

More recently, the cycle appears to be shifting towards net southern flows – that is, less gas flowing north in summer and more flowing south in winter. Across most of 2020, net flows were southward. However, in the fourth quarter of 2020, net flows north were at the highest level in 3 years in response to increase LNG export demand. The day-ahead auction supported this turnaround as participants bought capacity on routes north (section 4.10.4). Notably, on the South West Queensland Pipeline 95% of all capacity purchased in the fourth quarter of 2020 was on routes north towards Wallumbilla

Data on trade flows may understate the extent of north–south gas trading. Some gas producers enter swap agreements to deliver gas to southern gas customers without physically shipping it along pipelines. An example is Shell's agreement with Santos to swap at least 18 PJ of gas.[84] Under the agreement, Shell draws on its CSG reserves to meet part of Santos's LNG supply obligations in Queensland, while Santos diverts gas from the Cooper Basin to

84 Santos, 'Santos facilitates delivery of gas into southern domestic market' [media release], August 2017.

meet demand in southern Australia.[85] The swap allows the producers to increase supply to the domestic market, while enabling Shell to avoid transporting gas on the South West Queensland Pipeline, which is contracted to near full capacity. To improve transparency, from 2021 participants' reporting requirements are expected to expand to encompass a range of bilateral arrangements, including physical swaps (section 4.14.1).

Gas flows into NSW

NSW produces little of its own gas, so it is highly trade dependent. Previously supplied by Victorian sources, as Queensland production fields ramped up and sent more gas south, NSW became reliant on Queensland gas to supplement declining Victorian gas production. As a result, gas volumes shipped along the Moomba to Sydney Pipeline and the South West Queensland Pipeline rose significantly.

The critical role of these pipelines in delivering gas to NSW on peak days highlights the risk of capacity constraints. The South West Queensland Pipeline in particular has little uncontracted capacity between Wallumbilla (Queensland) and Moomba (South Australia), which is the origin point of the Moomba to Sydney Pipeline. But capacity trading reforms introduced on 1 March 2019 eased pressures somewhat (section 4.10.4). In addition, proposals for LNG import terminals, and gas pipelines that may open flows from Queensland, could improve gas availability in NSW. In particular, the Port Kembla import terminal is significantly progressed and is expected to alleviate short term supply concerns.

4.10.4 Pipeline access

Wholesale gas customers buy capacity on transmission pipelines to transport their gas purchases from gas basins. Gas production companies and gas pipelines are separately owned, so a gas customer must negotiate separately with producers to buy gas and with pipeline businesses to have the gas delivered. To reach its destination, gas may even need to flow across multiple pipelines with different owners.

Since LNG exports began in 2015, gas flows from the southern states to Queensland, and sometimes the reverse, have helped manage inter-regional supply–demand imbalances. For this reason, access to transmission pipelines on key north–south transport routes is critical for gas customers. But many critical pipelines have little or no spare, uncontracted capacity, making it difficult to negotiate access. In addition, many pipelines face little competition and charge monopolistic prices.

In 2015 the ACCC found a majority of transmission pipelines on the east coast were using market power to engage in monopoly pricing.[86] Reforms were implemented to address this issue, including a new information disclosure and arbitration framework that came into effect in August 2017; and changes to full and light regulation, which came into effect in March 2019 (section 5.3).

Reforms introduced in March 2019 made it easier to access pipeline capacity that is not fully used. Capacity on some pipelines is fully contracted to gas shippers, who do not fully use it. The reforms give other parties an opportunity to access this capacity through trading platforms.

Capacity can be acquired in 2 ways. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold in this way must be offered at a mandatory day-ahead auction. Any shipper can bid at the auction, which is finalised shortly after the nomination cut-off time a day in advance of the relevant gas day.

Auction revenues go to the pipeline, or facility operator, rather than the shippers that own the capacity rights. The auctions have a reserve price of zero, and the majority of settlements in 2020 occurred at no cost.[87]

To promote transparency, the Gas Bulletin Board publishes prices and other key terms from all voluntary trades and auctions. The AER monitors compliance with capacity trading regulations and the proper reporting of trades; and oversees the resolution of any cost recovery disputes.

85 EnergyQuest, *EnergyQuarterly*, March 2020.

86 ACCC, *Inquiry into the east coast gas market*, April 2016, p 18.

87 While participants can win capacity for $0 per GJ, additional charges and registration fees make the real cost slightly higher.

Pipeline capacity trading

In 2021 the AER reported on how the day-ahead auctions provided access to over 73 PJ of contracted but un-nominated pipeline capacity (across 12 facilities) in the 2 years after it launched on 1 March 2019 (figure 4.14). Of this, around 80% of this capacity was won at the reserve price of zero.

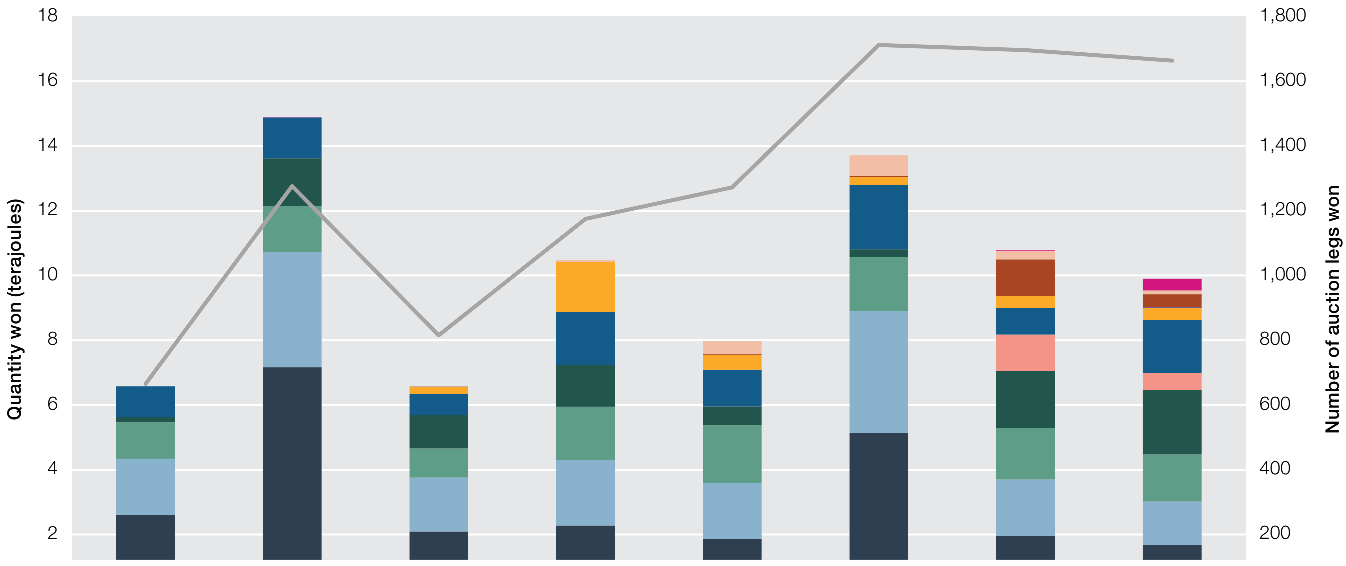
In the 2 years to March 2021 there has only been one trade on the voluntary capacity trading platform: 1 TJ of capacity for $0.02 per GJ. The ACCC reported shippers expect activity in the capacity trading platform to increase over time.[88]

The day-ahead auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low priced northern gas into southern spot markets, easing price pressure in those markets. The AER estimated the auctions effectively reduced monthly average spot gas prices by as much as $0.63 per GJ in Sydney over the 2 years to December 2020.[89]

The AER's *Pipeline capacity trading – two year review* found day-ahead auction capacity increased liquidity in both upstream and downstream markets. It also reported on how the auction can indirectly ease supply costs for some gas powered generators in the National Electricity Market (NEM). As an example, on 24, 25 and 26 August 2020, when electricity spot prices were high in Victoria, participants used the day-ahead auction to secure additional capacity in response to gas generators running harder than anticipated. Participants win most auction capacity in winter months, particularly on the Moomba to Sydney and South West Queensland pipelines, to assist delivery of gas to southern markets.[90]

However, auction activity on some pipeline remains low. In particular, the AER reported that no capacity has been purchased for the SEA Gas Pipeline System despite there being auction capacity available.[91] The other pipeline connecting to the Adelaide market, the Moomba to Adelaide Pipeline System, has also seen limited trade, although participation is increasing. Under-utilisation of these pipelines may result from higher fees and lower activity levels in Adelaide compared to other markets. Auction fees can discourage smaller players in particular. While the majority of capacity is won at the reserve price of $0 per GJ, the total cost is higher, as participants need to pay pipeline and storage operators for facility use (which can include both fixed and variable fees). Smaller participants also may be required to provide credit support, or collateral to use auction services, and in some cases these costs can be significant.

Figure 4.14 Day-ahead auction quantities won, by facility



BWP: Berwyndale to Wallumbilla Pipeline; CGP: Carpentaria Gas Pipeline; EGP: Eastern Gas Pipeline; ICF: Iona Compression Facility; MAPS: Moomba to Adelaide Pipeline; MCF: Moomba Compression Facility; MSP: Moomba to Sydney Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of day-ahead auction data.

88 ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, February 2020, pp 103–104.

89 AER, *Pipeline capacity trading – two year review*, March 2021, p 23.

90 AER, *Wholesale markets quarterly – Q3 2020*, November 2020, p 30.

91 AER, *Pipeline capacity trading – two year review*, March 2021.

4.11 Gas prices

The launch of LNG exports from Queensland in 2015 linked domestic gas prices (which were traditionally fairly stable) to more volatile international oil and gas prices. This link drove prices higher in 2016 and 2017, but operated in reverse in late 2019 and 2020 when lower Asian prices helped drive falls in domestic spot prices.

Other factors contributing to lower domestic prices across 2020 included high levels of Queensland gas production, increased competition in spot gas markets, decreased demand for gas powered generation, and the availability of cheap capacity through the day-ahead auction. The auction in particular allowed some shippers to move gas from northern to southern markets at near zero transportation costs.

4.11.1 Gas contract prices

A majority of gas prices are agreed in confidential bilateral contracts, either between gas producers and large customers or between retailers/aggregators and C&I customers (section 4.9.1).

Domestic gas contract prices historically averaged around $3–4 per GJ. But, when Queensland's LNG projects began sourcing gas from Victoria and South Australia, this demand drove contract prices higher. By early 2017 domestic prices of $22 per GJ were being quoted for a one or 2-year contract – almost $10 per GJ above export prices.[92] At their peak in March 2017, domestic prices offered by retailers nearly doubled LNG netback prices (box 4.3).

Following the Australian Government's market intervention in 2017 (section 4.10.1), Queensland producers began offering more gas to the domestic market at lower prices. By 2018 contract offers had eased into the high $8–11 per GJ range, aligning them more closely with Asian LNG netback prices. In late 2018 domestic prices separated significantly from Asian LNG netback prices due to a short term international price spike as domestic prices flattened out. Across 2019 and 2020 these prices generally decreased together, resulting in falls in contract offer prices.

Prices offered by both producers and retailers for 2021 supply were mostly in the $6–8 per GJ range over 2020.[93] This was a significant reduction from a year previous. Similarly, contract prices agreed to by C&I users decreased notably in 2020, falling to under $8 per GJ. This likely reflects depressed Asian LNG prices across 2020.

Across 2019 producer offers diverged from LNG netback prices as netback prices fell at a more rapid pace. In some instances, producer offers included new pricing structures, such as a fixed price component, on top of an LNG spot price linked component.[94] This trend continued across 2020, although the price disparity narrowed somewhat in the second half of the year.

In contrast with price trends in the north, average prices offered by producers and retailers in the southern states in 2020 fell below expected LNG netback prices (factoring in pipeline costs). The ACCC noted an improvement in the competitive dynamic over 2020 has contributed to this fall in prices, amongst other factors.[95]

Despite gas prices easing, the ACCC reported many C&I users are experiencing difficulties in procuring gas beyond 2022. Where suppliers have provided offers, users report concerns around future supply resulting in risk premiums being incorporated into contract prices.[96]

92 ACCC, *Gas Inquiry 2017–2020, interim report, July 2018*, August 2018.

93 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 7.

94 ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, February 2020, pp 1, 44.

95 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 61.

96 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 70.

Box 4.3 Liquefied natural gas netback prices

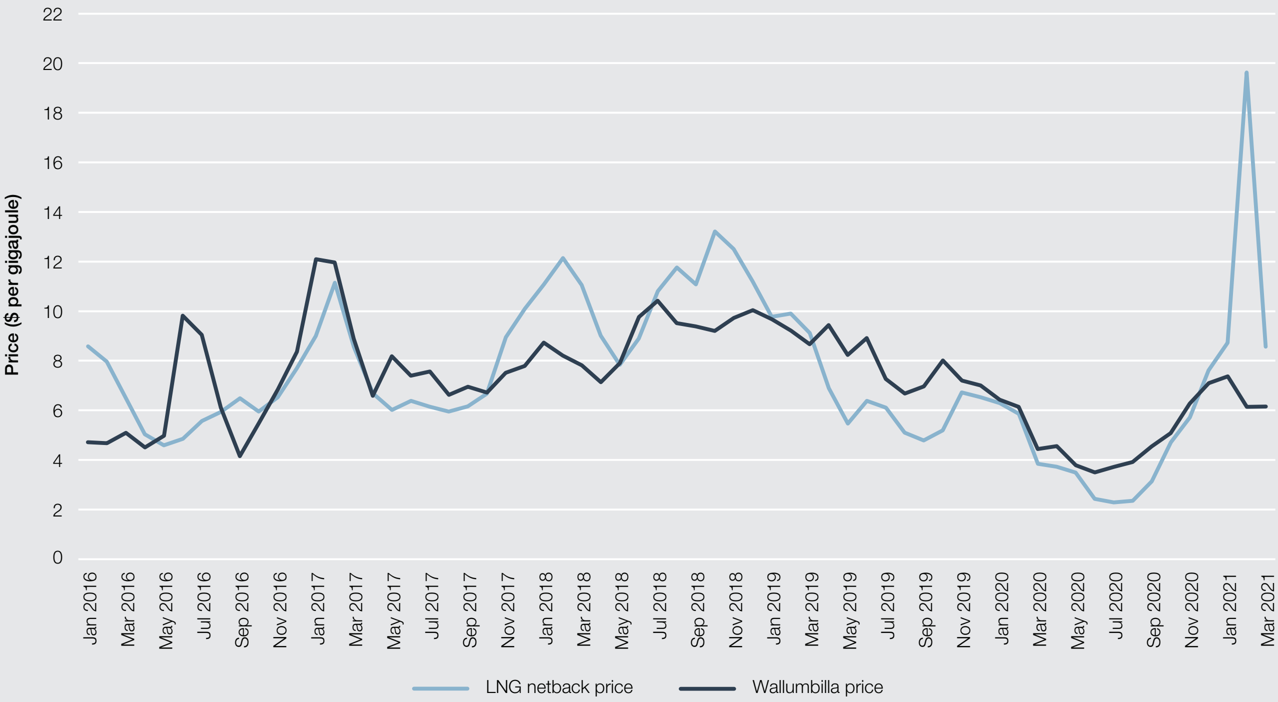
Liquefied natural gas (LNG) netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically. It is calculated as the price for selling LNG (based on Asian spot prices) and subtracting or 'netting back' the costs of converting gas to LNG and shipping it overseas. The costs include liquefaction at Gladstone, waterborne shipping to Asia, and regasification in Asia.

If LNG netback prices exceed domestic prices then it becomes more profitable to export gas than to sell it locally. At times in 2017 the reverse situation prevailed in eastern Australia – that is, domestic gas prices exceeded LNG netback prices (figure 4.15). This situation was indicative of a dysfunctional domestic market, where price signals were not addressing a demand–supply market imbalance.

The Australian Competition and Consumer Commission (ACCC) publishes LNG netback prices to improve transparency in the eastern gas market. The prices tend to peak during the northern hemisphere winter, when LNG demand is highest. After falling across most of 2019, netback prices were volatile in 2020. They bottomed out at a record minimum of $2.29 per GJ in July 2020 before rising sharply to a record high of $19.62 per GJ in February 2021.

Since peaking, LNG netback prices have fallen significantly from that record, returning to $8.56 per GJ in March 2021. It is expected to remain at levels higher than seen across 2020 for the rest of the year.[97]

Figure 4.15 LNG netback prices and Wallumbilla prices



Note: The Wallumbilla price is the monthly volume weighted average price at the Wallumbilla hub for day-ahead, on-screen trades. LNG netback prices are a simple average, based on domestic spot market prices on the first day each month, and expected netback prices for LNG cargoes to Asia in the following month. The 1 April LNG netback price, for example, is based on domestic spot prices for the 1 April gas day and the netback on expected LNG spot prices for cargoes to Asia in the following month.

Source: AER analysis of gas supply hub data; ACCC (LNG netback prices).

97 ACCC, LNG netback price series, April 2021.

4.11.2 Spot market prices

As discussed in section 4.9, 3 separate spot markets for gas operate in eastern Australia – gas supply hubs at Wallumbilla, Queensland, and Moomba, South Australia; the STTMs in Sydney, Brisbane and Adelaide; and Victoria's declared wholesale gas market. The 3 spot markets operate under different sets of rules, do not interact with each other and have different purposes. Price outcomes in the spot markets do not align with contract prices, although they often move in similar directions. Contract prices reflect expectations of future market conditions, but the spot markets reflect short term shifts in market conditions relating to factors such as the timing of LNG shipments and conditions in the electricity market.

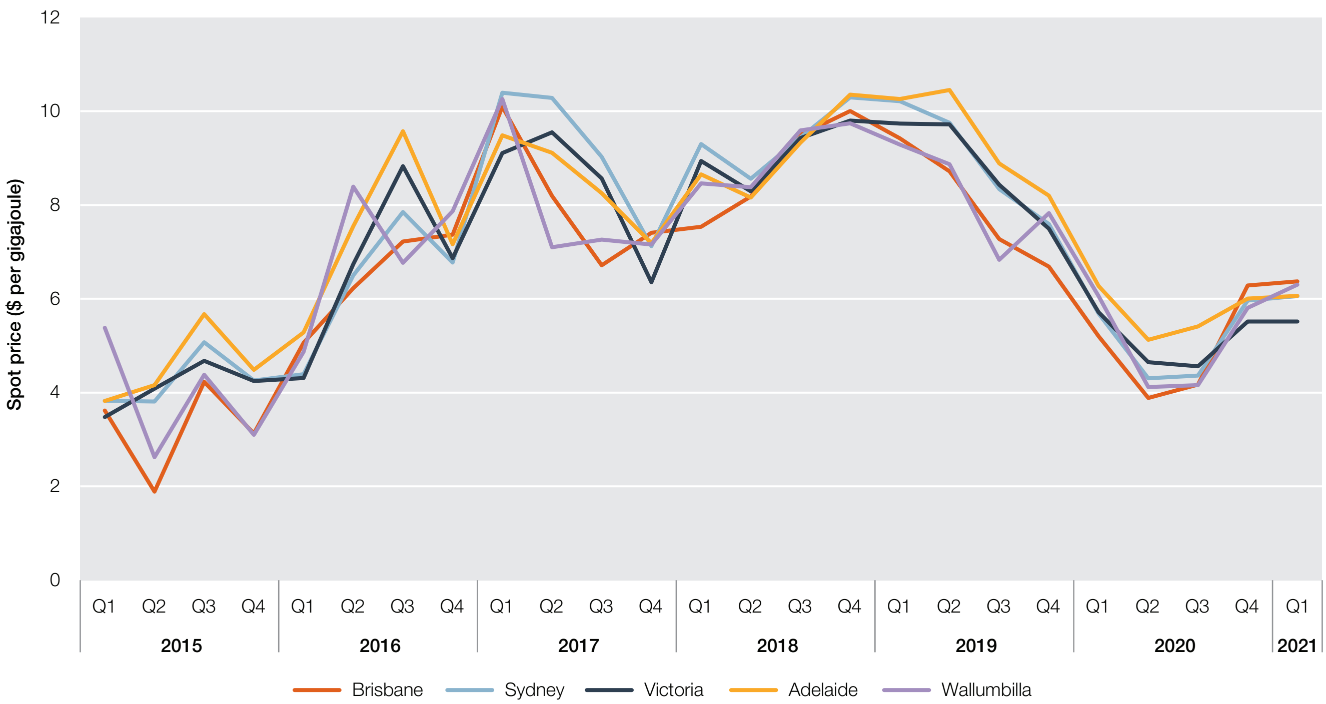
Spot prices vary seasonally, both within and across the markets. Prices can peak in summer but more typically peak in winter. In summer, gas demand for electricity generation may push up domestic spot prices. Australia's summer also coincides with the northern hemisphere winter, when Asian demand for LNG peaks. In the Australian winter, household gas demand tends to rise in the southern states for heating purposes. This increase in demand tends to push southern prices above northern prices during the winter months as southern customers pay the cost of northern gas plus domestic transportation costs (box 4.4).

In recent years, prices have varied significantly (figure 4.16). Along with other factors, the launch of LNG exports in January 2015 caused spot prices to increase in 2016 and 2017 as LNG producers competed with domestic customers for gas supplies (figure 4.17). While prices stabilised somewhat across late 2017 to 2018, they remained at historically high levels before reducing across late 2019 and into 2020.

In the fourth quarter of 2019 spot prices averaged around $8 per GJ. However, by the end of the second quarter of 2020 prices had fallen significantly to below $5 per GJ in all markets except Adelaide ($5.13 per GJ). As demand for LNG exports fell from record highs, Queensland production did not decline in a similar fashion. This, combined with a reduction in gas used for electricity generation, lowered domestic prices. At this time, the gap between the northern and southern markets narrowed significantly as a result of low southern demand and access to cheap capacity through the day-ahead auction.

This steep reduction in domestic prices also mirrored falls in international LNG prices. A greater available supply of LNG combined with intensive price competition and reduced demand due to COVID-19 resulted in the ACCC's LNG netback price falling to $2.29 per GJ in July 2020 – down from $6.72 per GJ in November 2019.

Figure 4.16 Eastern Australia gas market prices



Note: The Wallumbilla price is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the 6 am schedule price.

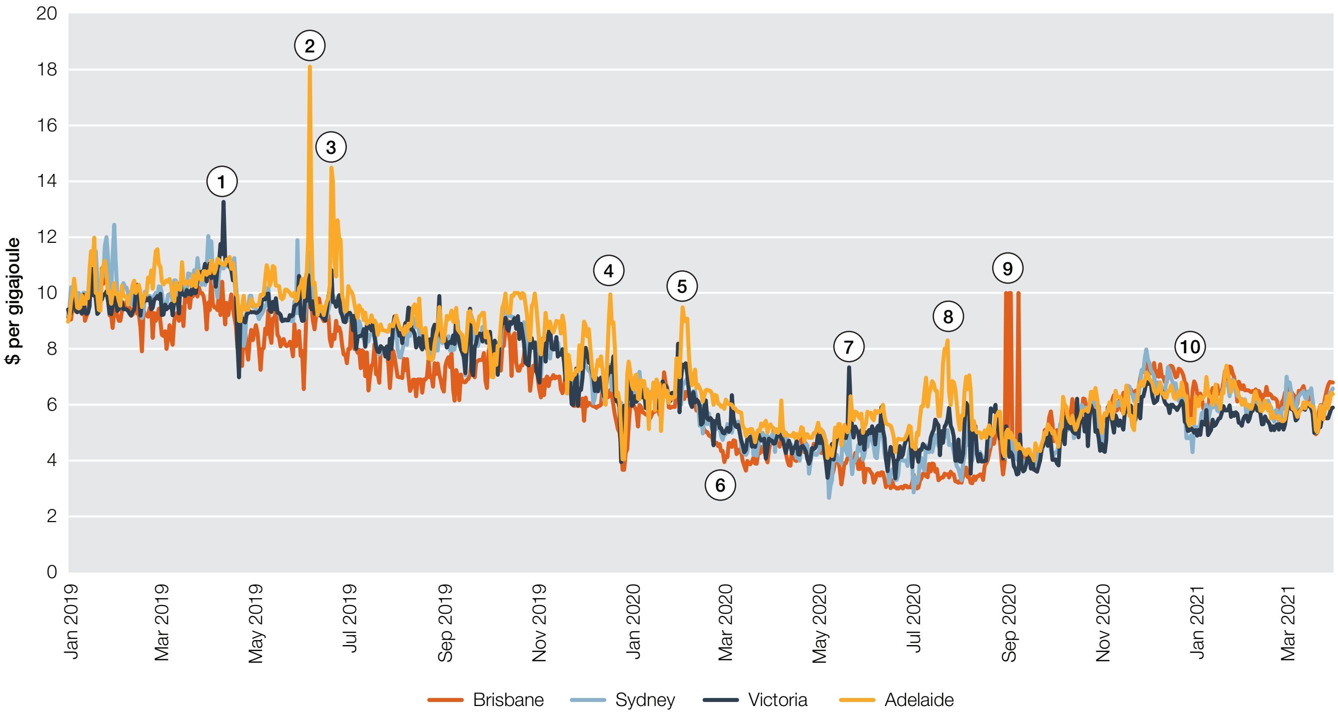
Source: AER analysis of gas supply hub, short term trading market and Victorian declared wholesale gas market data.

Domestic prices levelled off in the third quarter of 2020 as international prices rebounded. Higher demand in winter, particularly in the southern states, resulted in quarterly average prices rising in all spot markets except Victoria. During the first week of August 2020, cold weather affected most of southern Australia, with some areas experiencing their lowest winter minimum or maximum temperatures on record. On 4 and 6 August 2020 AEMO declared a threat to system security as winter demand peaked. This drove record high demand in the Sydney market on 6 August of 382 TJ (surpassing the previous record of 377 TJ set 9 years earlier) as participants withdrew gas from Sydney to inject into Victoria. Despite these dynamics, there was not a significant impact on average Sydney or Victorian prices.

By the end of 2020 prices had rebounded in all markets to levels similar to the start of the year. In the fourth quarter of 2020 northern market prices exceeded southern market prices for the first time in more than 2 years. This continued into early 2021, coinciding with a sharp spike in demand for LNG exports in December 2020 and January 2021 as a result of an unexpected cold snap in Asia (section 4.10.2). Over this time, LNG netback prices peaked at nearly $20 per GJ before falling again by the start of February 2021.[98]

Despite the magnitude of this international price spike, a number of factors meant domestic price rises were more moderate. First, to meet record export demand, LNG exporters increased production from already high levels to record output, averaging over 4,240 TJ per day. At the same time, domestic demand fell as gas used for electricity generation was lower. As a result of lower demand, the southern markets were less reliant on northern production, and excess gas flowed from south to north.

Figure 4.17 Daily gas spot prices



1. 11 April 2019: Longford constrained.
2. 6 June 2019: Low wind generation and production outages in Victoria.
3. 20 June 2019: Low wind generation and high winter gas demand in Victoria and Adelaide.
4. 16–20 December 2019: High temperatures in southern states.
5. 2–7 February 2020: Gas generation directed on in South Australia following the outage of the Heywood interconnector in the NEM.
6. March 2020: LNG export train outage, excess gas supply and low gas generation demand.
7. 21 May 2020: Market demand forecast revised upwards in Victoria during a cold front affecting south east Australia. Uncertainty around demand levels due to COVID-19 impacts (demand profiles deviating from historical trends)
8. 13 July to 8 August 2020: Period of high gas powered generation in South Australia, with significant balancing gas allocations resulting from the diversion of scheduled gas supply towards generation assets. Victorian price spikes linked to high demand due to cold weather.
9. 2–8 September 2020: An unplanned outage at the Dalby compressor station on the Roma to Brisbane Pipeline resulted in high ex ante market prices and capacity constraint pricing.
10. October to December 2020: High domestic prices coincided with international price increases and a significant ramp-up in LNG exports across the fourth quarter of 2020.

Source: AER; AEMO (raw data).

98 ACCC LNG netback price, February 2021. Price assessments take place over the monthly window leading up to about 6 weeks before expected delivery.

4.12 Market responses to supply risk

Market responses to concerns about a shortage of domestic gas in coming years are being explored. Options include further gas development, LNG imports, transmission pipeline solutions, and demand response.

4.12.1 Gas field development

Exploration and development in a number of gas fields have increased since international oil and gas prices began to rise in 2017. Additionally, domestic gas prices and government funding improved the economics of some resources and projects. Governments across jurisdictions are offering financial or regulatory incentives for projects that target gas supplies to the domestic market (section 4.13).

The Australian Government's gas fired recovery plan, the South Australian and NSW governments' plans to unlock additional gas supply, and Queensland's 'domestic only' exploration tenement release are among the schemes being implemented.

Many efforts to increase gas supply focus on unconventional projects, which often face community opposition due to environmental concerns. Legislative moratoriums on onshore exploration and fracking have impeded the development of gas projects in Victoria, South Australia and Tasmania (section 4.10.1). Elsewhere, stringent regulatory processes apply, as highlighted by the extensive process for Santos's Narrabri gas project in NSW. Against this trend, in April 2018 the Northern Territory lifted its moratorium on fracking in 51% of the jurisdiction.

Despite the various moratoriums and constraints in place, sharply lower international oil prices in 2020 and impact of COVID-19, a number of projects are progressing that could bring additional supply to the domestic market:

- In Victoria, Cooper Energy's Sole gas field in the Gippsland Basin commenced operation in late March 2020. The gas is processed at the Orbost plant, which can produce up to 68 TJ per day after recommissioning upgrades. Across 2020 production varied significantly as the plant faced issues.[99] Cooper Energy is also exploring opportunities in the Gippsland and Otway basins for development in 2022.
- In the Otway Basin, in February 2020 Beach Energy delivered its first gas from its Haselgrove-3 project.[100] Gas from the project, which has a capacity of 10 TJ per day, feeds into the new Katnook gas processing facility (South Australia), which the Australian Government's Gas Acceleration Program (GAP) scheme partly funded.
- In NSW, Santos proposed to develop 850 wells across its 95,000 hectare Narrabri gas project, which has potential to supply up to 200 TJ per day.[101] Environmental and community groups opposed the project's environmental impact: over 23,000 submissions were made in response to the environmental impact statement, mostly in opposition.[102] As a result, the project has faced various regulatory and legal delays. In September 2020 the project received approval from the NSW Independent Planning Commission, and in November 2020 the Australian Government also delivered its approval.[103]
- In Queensland, the Kincora project (Armour Energy) began processing gas from surrounding wells in December 2017.[104] Armour Energy expanded its activity in the region after receiving a $6 million grant under the GAP scheme in March 2018. Kincora also won a Queensland Government 'domestic only' tenement release for gas exploration, based on a commitment to supply gas to the domestic market (section 4.13.5).[105] Armour Energy targeted output of 20 TJ per day by the end of 2020, but production growth has been restricted. It produced on average 6 TJ per day in the fourth quarter of 2020.[106]

Participants delayed some projects in response to economic conditions over 2020. In March 2020 Santos announced a 38% reduction in 2020 capital expenditure as a result of COVID-19 and other factors.[107] Similarly, in April 2020 Origin Energy announced a pause in exploration activities in the Beetaloo Basin and a reduction in APLNG development and exploration as a result of changing conditions.[108]

99 EnergyQuest, *EnergyQuarterly,* March 2021, p 27.
100 EnergyQuest, *EnergyQuarterly*, March 2020, p 105.
101 Santos, *Narrabri Gas Project*, Santos website, accessed 28 May 2021.
102 Department of Planning and Environment (NSW), 'NSW Government assessment of the Narrabri Gas Project proposal update' [media release], 23 April 2018.
103 Santos, 'Santos welcomes federal signoff on Narrabri Gas Project' [media release], 24 November 2020.
104 Armour Energy, *Surat Basin*, Armour Energy website, accessed 28 May 2021.
105 Armour Energy, *Surat Basin*, Armour Energy website, accessed 28 May 2021.
106 EnergyQuest, *EnergyQuarterly*, March 2021, p 99.
107 Santos, 'Santos, COVID-19 response and business update' [media release], 23 March 2020.
108 Origin Energy, 'Operational and financial update' [media release], 6 April 2020.

4.12.2 Liquefied natural gas import terminals

To address future supply concerns, the industry is considering at least 5 projects to develop LNG import facilities on the east coast (section 4.8). Each project would involve importing LNG through floating storage and regasification units.

4.12.3 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in January 2019. Current nameplate capacity of the pipeline is 90 TJ per day, but Jemena plans to increase this to 200 TJ per day by 2025.[109] This plan would also extend the pipeline to connect the Beetaloo Basin directly to the Wallumbilla gas supply hub.

4.12.4 Demand response

Volatile markets and the expiry of legacy gas supply agreements are prompting C&I customers to take a more active role in gas procurement. Some customers are becoming direct market participants by engaging in collective bargaining agreements. As an example, in November 2017 the ACCC granted authorisation to the Eastern Energy Buyers Group of agribusinesses to establish a joint energy purchasing group to run gas and electricity supply tenders for 11 years. The arrangement allows the group to access wholesale markets at better prices than would be possible if the agribusinesses acted individually.[110]

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, using brokers to secure supply agreements, participating in gas markets, and investing in new LNG import facilities.[111] Further, some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments. The ACCC reported one C&I user citing high gas prices as a major factor in delaying a $15 million expansion.[112]

Joint ventures between gas customers and producers are also occurring.[113] Incitec Pivot, with Central Petroleum, won a tender for a CSG tenement release by the Queensland Government and aims to be producing by 2022.[114]

In addition, some C&I users are considering alternatives to gas. Incitec Pivot, for example, is investigating the use of renewable energy instead of natural gas for expanding future ammonia production. Similarly, Australian Paper is developing a waste-to-energy plant, which could reduce its gas use by 4 PJ per year.[115]

109 Jemena, 'Jemena partners with shale gas experts to develop Beetaloo' [media release], November 2020.
110 ACCC, *The Eastern Energy Buyers Group – authorisations – A91594 & A91595*, August 2017.
111 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, pp 73–74.
112 ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, 18 February 2020, p 75.
113 AEMO, *2018 gas statement of opportunities*, June 2018.
114 EnergyQuest, *EnergyQuarterly*, March 2020, p 108.
115 ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, February 2020, p 74.

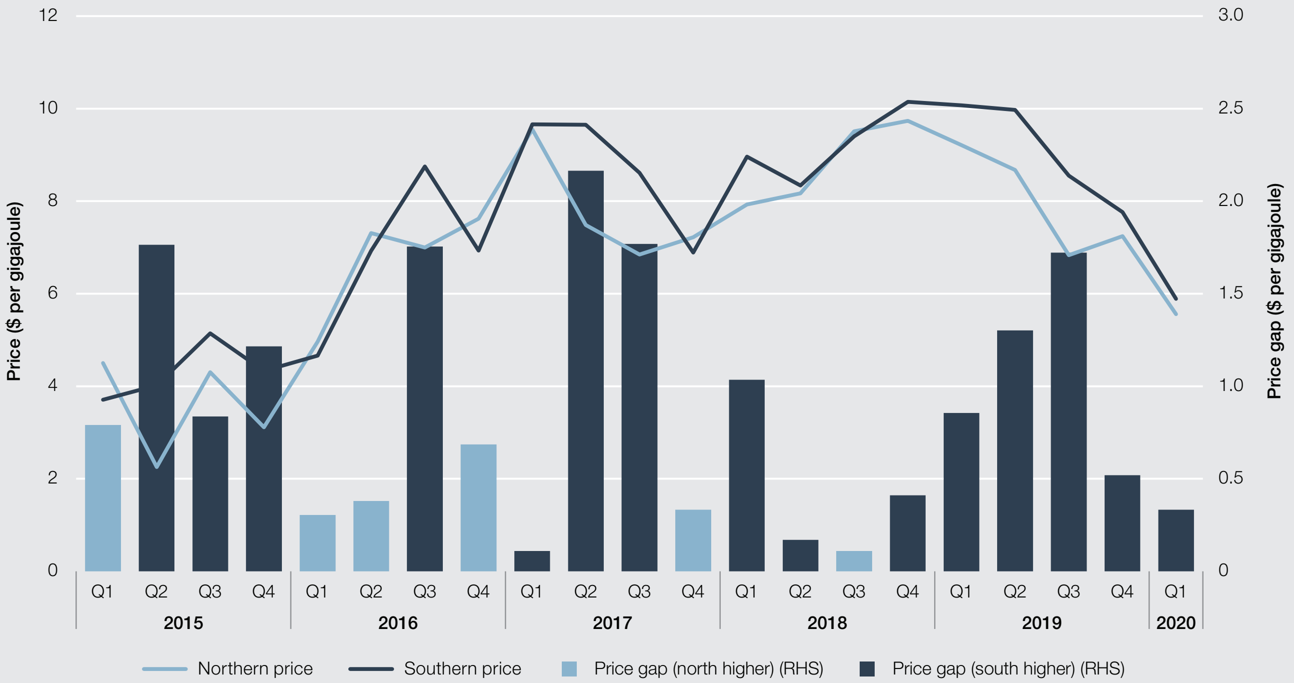
Box 4.4 North–south price divide

The differential between spot gas prices in Queensland (Wallumbilla and Brisbane) and the southern states fluctuated across 2020 (figure 4.18). The differential reflects contrasting demand and supply conditions in the 2 regions. With reduced demand for liquefied natural gas (LNG) exports across mid-2020, Queensland producers diverted gas to domestic markets, resulting in lower northern prices. But late in the year LNG export demand spiked sharply, and as a result significant quantities of gas flowed from south to north. This caused northern market prices to become more expensive than the southern markets for the first time in over 2 years.

Historically, price gaps tend to emerge each winter as southern gas demand for heating increases. The gap can be as much as $2 per gigajoule (GJ), roughly the cost of transporting Queensland gas to the southern states.

But in 2019 and 2020, the day-ahead auction kept the price gap narrower than it might have been. Access to cheap (or free) pipeline capacity allowed some participants to sell northern gas to southern markets at more competitive prices. Without this cheap pipeline access, southern prices would likely have been higher (section 4.10.4).

Figure 4.18 North–south gas price divide



RHS: Shows the price gap between northern and southern markets.

Note: The southern market is the average of NSW, Adelaide and Victorian spot prices. The northern market is the average of Brisbane and Wallumbilla spot prices. The Wallumbilla price used for calculation is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub.

Source: AER analysis of gas supply hub, short term trading market and Victorian declared wholesale gas market data.

4.13 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand, the Australian Government and some state governments have intervened in the market. The interventions are noted throughout this chapter and summarised here.

4.13.1 Gas fired recovery plan

As part of a broader COVID-19 recovery plan, in September 2020 the Australian Government announced a number of measures to facilitate the development of new sources of supply. This plan includes a number of proposed actions, including:[116]

- setting new gas supply targets with states and territories, and enforcing 'use it or lose it' requirements on gas licences
- funding plans for further development of key gas basins and exploring options for a gas reservation scheme
- extending the heads of agreement with Queensland producers
- identifying, through a National Gas Infrastructure Plan, priority pipelines and critical infrastructure and highlight when the government will step in if private sector investment is not forthcoming.

The Australian Government is progressing these commitments. For example, in March 2021 it announced $50 million in grants to support exploration that occurs in the Beetaloo Basin before the end of 2022.[117]

Also, in May 2021 the Australian Government released the *National Gas Infrastructure Plan: interim report*, which identified a range of priority projects that could alleviate expected gas supply shortfalls from 2024.[118] Critical projects identified include the Golden Beach storage facility, expansion of the Iona storage facility and South West Queensland Pipeline, and the development of an LNG import facility. The report also noted that expanded northern production and additional supply from new southern fields, such as the Narrabri Gas Project, would contribute to addressing forecast shortfalls.

4.13.2 Australian Domestic Gas Security Mechanism

In 2017 the Australian Government threatened to direct gas producers to increase gas supplies to the local market. The Australian Domestic Gas Security Mechanism, which took effect on 1 July 2017, empowers the Resources Minister to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[119] The Resources Minister may determine in the preceding September whether a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

To avoid export controls, Queensland's LNG producers entered a heads of agreement with the government in October 2017, a second agreement in September 2018 and a third agreement in December 2020.[120] Under the agreements, they committed to offer uncontracted gas on reasonable terms to meet expected supply shortfalls. They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.[121] To meet their commitments, the LNG projects adopted a range of strategies to offer more gas domestically (section 4.10.1).

The AEMC reported some stakeholders were concerned that government intervention, while it may increase liquidity in the short term, does not correct participants' lack of confidence that they can source gas where they need it at a reasonable price. Concerns were also raised that intervention may reduce investment certainty and weaken liquidity in the long term.[122]

In 2019 the Department of Industry, Innovation and Science found the scheme had worked effectively to safeguard domestic gas supplies.[123] Following this finding, the scheme was extended until 1 January 2023.

116 Australian Government, 'Gas-fired recovery' [media release], September 2020.

117 Department of Industry, Science, Energy and Resources, *Unlocking the Beetaloo: The Beetaloo strategic basin plan*, DISER website, accessed 28 May 2021.

118 Australian Government, *National gas infrastructure plan interim report*, May 2021.

119 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism*, July 2018.

120 Department of Industry, Science, Energy and Resources, *Securing Australian domestic gas supply*, DISER website, accessed 28 May 2021.

121 The agreement specifically notes that LNG netback prices, as referenced by the ACCC, play a role in influencing domestic gas prices.

122 AEMC, *Final report: biennial review into liquidity in wholesale gas and pipeline trading markets*, August 2018, p 46.

123 Department of Industry, Science, Energy and Resources, *Australian Domestic Gas Security Mechanism review*, January 2020.

4.13.3 Gas supply guarantee

In March 2017 facility and pipeline operators developed the gas supply guarantee as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM.[124] The guarantee identified new processes to assess and resolve potential gas supply shortfalls ahead of time.

While the guarantee has not been used, and was due to expire in March 2020, the Australian Government extended the guarantee to March 2023.[125]

4.13.4 National gas reservation scheme

In late 2020, the Australian Government consulted on options for a national gas reservation scheme.[126] It expects to reach a final decision in the first half of 2021.[127]

4.13.5 Gas Acceleration Program

To encourage gas supply, in 2017 the Australian Government launched the $26 million GAP, offering grants of up to $6 million for projects that increase domestic gas flows in the eastern market by 30 June 2020. Four of the 5 successful projects were based in Queensland, including Armour Energy's Kincora expansion, Westside's Greater Meridian project, Tri-Star Fairfield's gas project, and Australian Gasfields' refurbishment of the Eromanga and Gilmore processing facilities. The fifth project was Beach Energy's new Katnook gas processing facility in the Otway Basin.[128]

While all projects have commenced operation, Beach Energy announced that it would be suspending operations at the Katnook Gas Plant during 2021–22 as a result of natural field decline.[129] Beach will assess whether to recommence operations at the plant in future years.

4.13.6 State government schemes

To encourage gas exploration, the Queensland Government offers grants for 'domestic only' exploration tenements.

As part of this grants program, it released almost 70,000 km^2 of land for exploration between 2015 and 2019, of which around 25% was reserved for domestic supply. The Queensland Government released a further 3,000 km^2 of land in September 2020, with over 15% tagged for domestic supply.[130]

In January 2020, through a memorandum of understanding with the Australian Government, the NSW Government committed to bringing new gas supplies to the domestic market. It set a target of injecting an additional 70 PJ of gas per year into the NSW market.[131]

In April 2021 the Australian and South Australian governments announced an agreement to invest in energy infrastructure and reduce emissions in South Australia. As part of this, the state set a target of an unlocking an additional 50 PJ per year by 2023.[132]

4.13.7 ACCC gas inquiry

In April 2018 the Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. While the inquiry was initially tasked to run until 30 April 2020, the Treasurer extended it in July 2019 to 2025. The ACCC has released several interim reports.[133]

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124 AEMO, *Gas supply guarantee*, AEMO website, accessed 28 May 2021.

125 AEMO, *Gas supply guarantee guidelines consultation final determination*, March 2020.

126 Ministers for the Department of Industry, Science, Energy and Resources (Australian Government), 'Review finds gas policy boosts domestic supply and helps lower prices' [media release], 24 January 2020.

127 Australian Government, *Options for a prospective national gas reservation scheme: issues paper*, October 2020.

128 Department of Industry, Innovation and Science, *Gas Acceleration Program successful applicants*, DIIS website, accessed 19 October 2018.

129 Beach Energy, *FY21 third quarter activities report*, April 2021.

130 Queensland Government, 'Queensland gas exploration ramping up' [media release], September 2020.

131 NSW Government, *Memorandum of understanding – NSW energy package*, 31 January 2020.

132 Australian Government, 'Energy and emissions reduction agreement with South Australia' [media release], April 2021.

133 ACCC, *Gas inquiry 2017–2025*, ACCC website, accessed 28 May 2021.

4.13.8 Electrification of liquefied natural gas production

On 8 February 2020 the Australian Government announced it would allocate up to $1.5 million for working with the Queensland Government and industry on electrifying the Curtis Island LNG facilities. The production facilities currently use their own gas as a power source in production. Partly electrifying these processes would free up to 12 PJ of gas for delivery to the domestic market.

4.13.9 National hydrogen strategy

The Australian Government identified hydrogen as a potential fuel to facilitate cuts to emissions across energy and industrial sectors. As part of this strategy, the government is looking at introducing hydrogen to the gas distribution network as part of the mix with natural gas. Currently, hydrogen can be added to gas pipelines at concentrations of up to 10% to supplement gas supplies, and a number of trials are being explored. In July 2020 the Australian Renewable Energy Agency shortlisted 7 projects to be considered as part of its $70 million fund to develop large scale electrolysers, 3 of which are based in eastern Australia.[134]

4.14 Gas market reform

The Energy National Cabinet Reform Committee (formerly CoAG Energy Council) directs gas market reforms, which regulatory and market bodies implement.[135] A key focus of reform is to address information gaps and asymmetries in the market. Consultation on the latest round of measures took place in 2019, and the CoAG Energy Council delivered the final decision regulation impact statement in late March 2020.[136]

Reform stems from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group. In 2016 the AEMC found that the eastern gas market is opaque and participants have low levels of confidence in the information that is available. The reforms aim to increase transparency in the gas market, improving the Gas Bulletin Board and improving the availability of information on market liquidity, prices and gas reserves.

4.14.1 Gas Bulletin Board reforms

The Gas Bulletin Board (www.gasbb.com.au) was launched in 2008 to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia. But its usefulness was compromised by gaps in coverage and, at times, the provision of inaccurate data.

Significant reforms in September 2018 brought the bulletin board closer to being a ‘one stop shop’ for the eastern gas system. The reforms removed reporting exemptions, mandated the provision of more comprehensive detail for covered facilities and extended reporting obligations to smaller facilities and those in Northern Territory. The reporting threshold for transmission pipelines, production facilities and storage facilities was lowered from 20 TJ per day to 10 TJ per day.

Additionally, more comprehensive reporting was mandated for production facilities. Market participants can now access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations, and capacity outlooks. This reporting adds transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must submit daily disaggregated receipt and delivery point data. The data include information on flows at key supply and demand locations along pipelines. Reporting obligations were also extended to regional pipelines and facilities attached to distribution pipelines.

To encourage compliance, the reforms made reporting obligations subject to civil penalties. The AER assesses the quality and accuracy of the data submitted by market participants against an ‘information standard’ to ensure the information presented on the bulletin board has integrity. The AER published a guidance note outlining its approach to enforcement.[137]

134 ARENA, *Seven shortlisted for $70 million hydrogen funding round*, ARENA website, accessed 28 May 2021.

135 Including the Energy Security Board, the AER, the AEMC, AEMO and the ACCC.

136 CoAG Energy Council, *Measures to improve transparency in the gas market – decision regulation impact statement*, March 2020.

137 AER, *Guidance note – natural gas services bulletin board (enhanced information reporting)*, September 2018.

Further reforms have been proposed that would extend reporting to large gas users and LNG processing facilities. The proposed reforms also introduce the reporting of gas reserves, gas sales and swaps, LNG exports and contract prices. Energy Ministers were consulting on the legal package to implement these reforms in late 2020.[138]

Liquidity information

In August 2018 the AER began publishing (on the industry statistics page of its website) quantitative metrics for assessing the liquidity of gas markets, and it regularly updates these metrics. In addition, the AER commenced quarterly reporting, from the third quarter of 2019, on the performance of the east coast gas markets. These quarterly reports build on the liquidity statistics and contain more detailed analysis of key performance indicators across the markets. These indicators have shown signs of improvement in liquidity over time. For example, spot market trade has grown from 10% of east coast demand in the fourth quarter of 2018 to a record high of 15% in the fourth quarter of 2020.[139]

Price and reserves transparency

With gas markets shifting towards shorter term contracts, and suppliers using EOI processes, the transparency of price and other market information is critical. Yet the market lacks a single indicative price for gas and lacks consistent gas reserve and resource information. The ACCC moved to address these issues in late 2018 when it began publishing new data on LNG netback prices.[140] The aim is for the data to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts.

Public information on gas reserves and resources in Australia also tends to lack clarity, consistency and accuracy. As such, market participants are less able to identify future supply issues and plan accordingly. For this reason, in late 2018 the ACCC began publishing data on gas reserves and resources, drawing on information provided by reserve owners.

4.14.2 Pipeline reforms

Gas produced in one region can help address a supply shortfall elsewhere, provided transmission pipeline capacity is available to transport the gas. But a number of key pipelines experience contractual congestion, which arises when most or all of a pipeline's capacity is contracted, making the pipeline unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity.

Three major pipelines – the South West Queensland Pipeline, the Moomba to Adelaide Pipeline System and the Moomba to Sydney Pipeline – were close to fully contracted in 2018, limiting shippers' ability to transport gas between northern and southern markets.[141]

To manage pipeline congestion issues, some gas producers engage in swap agreements. They bypass the need for transportation arrangements with pipeline operators by 'swapping' rights to gas held in different physical locations. However, the ACCC found that such agreements are complicated, involve extensive negotiations and, by necessity, reveal parties' commercial positions to their competitors. Such agreements are unlikely, therefore, to be an effective long term solution to gas pipeline issues.[142]

Secondary trading in underused capacity

Congestion issues focused policy attention on ensuring any spare physical pipeline capacity is made available to the market. Reforms to launch a voluntary trading platform and a secondary compulsory auction of underused capacity took effect in March 2019. Since its commencement, the day-ahead auction in particular has had a positive impact on the east coast gas markets (section 4.10.4).

To promote transparency, the Gas Bulletin Board publishes prices and other key terms in all voluntary trades, as well as the day-ahead auction results. The AER monitors compliance with capacity trading regulations and the proper reporting of trades.

138 Energy National Cabinet Reform Committee, *Measures to improve transparency in the gas market*, November 2020.

139 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

140 ACCC, *Gas inquiry 2017–2020 – LNG netback price series*, ACCC website, accessed 28 May 2021.

141 ACCC, *Gas inquiry 2017–2020, interim report, December 2017*, December 2017, p 59.

142 ACCC, *Gas inquiry 2017–2020, interim report, December 2017*, December 2017.

Information disclosure and arbitration

Negotiating a fair price to use a gas pipeline is an ongoing issue, with a number of reviews raising concerns about monopolistic pricing practices.[143] The reviews highlighted a lack of transparency and unequal bargaining power between shippers and pipeline operators.

These concerns led to the introduction of Part 23 of the National Gas Rules in August 2017. Part 23 requires otherwise unregulated pipeline businesses to disclose financial, service and access information, following guidelines published by the AER. Customers can use the disclosed information to negotiate gas transport contracts with pipeline operators. If agreement cannot be reached, an access seeker may apply for arbitration. Chapter 5 details the Part 23 regime.

Scope of pipeline regulation

In July 2018 the AEMC reviewed the effectiveness of current gas pipeline regulation. Various tiers of pipeline regulation apply, including full regulation, light regulation, 15-year exemptions, Part 23 regulation and Part 23 exemptions.[144] The review recommended removing a number of inconsistencies across these tiers.

In late 2019 the CoAG Energy Council consulted on a regulatory impact statement as part of consultation on options for delivering a more efficient, effective and integrated framework for regulating gas pipelines. The Energy National Cabinet Reform Committee delivered a final decision in May 2021.[145] This decision proposed:

- requiring all pipelines to provide third-party access and to be subject to an either 'stronger' or 'lighter' form of regulation, based on the existing regulation structure, with additional constraints on the exercise of dynamic market power
- a new 15-year 'greenfields' exemption from stronger regulation for new pipelines where it can be demonstrated the pipeline is unlikely to have substantial market power over that period
- removing the coverage test from the regulation assessment framework
- new powers to allow regulators to actively monitor pipeline operators for exercises of market power and to refer pipelines for regulation assessment
- introducing a single negotiation framework across all forms of regulation; and additional measures to improve dispute resolution options for smaller shippers
- increased information reporting obligations, including improved price disclosure requirements.

It is anticipated that the new regulatory framework will commence in 2022.

4.14.3 Gas day harmonisation

On 1 October 2019 the gas day start time for each market was standardised to 6.00 am. From their commencement, the different gas markets in the east coast operated with different start times, as a result of historical pipeline arrangements. This difference resulted in unnecessary costs and complexities for participants that operate over multiple locations. Harmonising the gas day start times will reduce these complexities, provide for more interconnection and help the development of standardised market reforms.

4.14.4 Australian gas hub

As part of its gas fired recovery plan, the Australian Government announced plans to reform the Wallumbilla gas supply hub into an Australian gas hub. The plan would include measures to improve liquidity and transparency. In early 2021 the Australian Government was consulting on this proposal ahead of implementation.

143 ACCC, *Inquiry into the east coast gas market*, April 2016, pp 99–106; CoAG Energy Council, *Examination of the current test for the regulation of gas pipelines*, December 2016.

144 Chapter 5 outlines the tiers of gas pipeline regulation.

145 Energy National Cabinet Reform Committee, *Options to improve gas pipeline regulation: regulation impact statement for decision*, May 2021.