# Downstream spot markets

## Wholesale gas market focus report

May 2025

AUSTRALIAN ENERGY REGULATOR

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# Contents

# Glossary

| Term | Definition |
| --- | --- |
| ACCC | Australian Competition and Consumer Commission |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| ASX | Australian Securities Exchange |
| CMOS | Counteracting Market Operator Service |
| DAA | Day Ahead Auction |
| DWGM | Declared Wholesale Gas Market |
| EGP | Eastern Gas Pipeline |
| GPG | Gas-powered generation |
| GSA | Gas Supply Agreement |
| HHI | Herfindahl-Hirschman Index |
| MAPS | Moomba to Adelaide Pipeline System |
| MOS | Market Operator Service |
| MSP | Moomba to Sydney Pipeline |
| NSW | New South Wales |
| OTC | Over-the-counter |
| STTM | Short Term Trading Market |
| VTS | Victorian Transmission System |

# Methodology toolbox

The methodology toolbox below summarises key methodological approaches and considerations made in relation to our monitoring and reporting responsibilities presented in this report.

| Aspect | Approach |
|---|---|
| Downstream spot markets | This focus report looks at the downstream spot markets – the Declared Wholesale Gas Market (DWGM) and the 3 Short Term Trading Market hubs (STTMs). We have used the short-hand reference to the 'spot markets' throughout the report and unless otherwise specified, this only refers to the downstream wholesale spot markets. |
| Participant grouping | We classified individual participants into groups to avoid the disclosure of commercially sensitive information. The groups are:<br>1. Exporters and producers<br>2. GPG gentailers<br>3. Traders<br>4. Industrials<br>5. Retailers.<br>Broadly, the 5 groups represent participants with the greatest similarity in operations and possible incentives.<br>As a result of the breadth of the groups and the diversity among participants, trends at the group level are not always consistent between participants within that group. For example, producers with access to export facilities may exhibit different strategies to those that only supply domestic markets. However, given the relatively small number of active participants in the producer and exporter category, we have grouped them together.<br>Where possible and relevant, we describe diversity within each group without reporting specific data or information that would allow precise analysis or recognition of individual participant activities or outcomes. |
| Reporting periods | The analysis in this report is primarily based on data provided by AEMO on DWGM and STTM gas trade between 1 January 2016 and 31 December 2024. |
| Supplementary analysis | This AEMO data has been supplemented with:<br>• financial data reported by the ASX between 1 January 2018 and 31 December 2024<br>• bilateral transactions up to a year in duration reported to the Gas Bulletin Board<br>• ACCC LNG netback price data |

| Aspect | Approach |
| --- | --- |
| | • contract data publicly reported by the ACCC in its Gas inquiry 2017–30 reports. |
| Net buying and selling | Most measures of trade in this report are based on net trade rather than total quantities bought and sold in the gas markets. This is because the downstream spot markets are balancing markets, where significant quantities traded each day are bought and sold by the same participant. Participants may choose to either supply more gas than needed to cover their own demand (net sellers) or be exposed to the market price and purchase gas where their demand is not met by their own supply (net buyers).<br><br>Our measure of net trade finds the daily net trade position in each market for a participant and sums these across the period analysed. Participants that are net sellers in a market one day and net buyers the next will show as having both a net buy and net sell position in the period assessed. For example, on a day where a participant buys 10 Terajoules (TJ) from the Victorian market and sells 10 TJ into the Sydney STTM, its position will show as net sell for Sydney and net buy for Victoria. |
| Herfindahl-Hirschman Index (HHI) | The HHI of the spot markets is derived from calculating the sum of the squared share of net buying and selling for all participants that year. HHI can range from zero (in a market with many firms with similar market share) to 10,000 for a monopoly.<br><br>The US Federal Energy Regulatory Commission merger policy thresholds broadly categorise an HHI below 1,000 as not concentrated, an HHI of 1,000 to 1,800 as moderately concentrated and an HHI above 1,800 as highly concentrated. |

# 1 Executive summary

This report is the AER's third and final focus report assessing whether specific facilitated markets have supported efficiency and competition in the east coast wholesale gas market.

This report focuses on the downstream spot markets – the Declared Wholesale Gas Market (DWGM) in Victoria and the 3 Short Term Trading Market hubs (STTMs) in Sydney, Adelaide and Brisbane.

The downstream spot markets:

- allow participants to trade gas outside of long-term gas supply contracts
- provide an efficient and transparent pricing system
- provide pricing signals that indicate where pipeline investment or new gas supply might be needed
- encourage retail contestability and the diversity of supply and upstream competition
- create a systemic approach to gas supply and system security.

All the downstream spot markets are operated by the Australian Energy Market Operator (AEMO), but the DWGM and STTMs have separate rules and price setting approaches.

Several developments have been made to improve the operation of the downstream spot markets since they were first established. In particular, government reforms of the east coast wholesale gas markets have sought to improve the efficiency of gas trading and support more effective and consistent management of price and volume risk in spot markets.

A previous government review identified several incremental reforms aimed at improving the performance of the east coast gas market, including the downstream spot markets. These reforms are in progress.[1] We do not have any further recommendations on improvements to the design of the downstream spot markets at this time.

## 1.1 Key insights

This report has several key findings:

- There has been substantial growth occurring in liquidity of net trading with volumes doubling since 2018, and spot prices appear aligned between hubs suggesting a liquid market between hubs.
- Financial products are being used, which can help participants manage spot market price volatility but liquidity and trade of DWGM futures has reduced considerably across the past 2 years. The AER intends to investigate financial products more broadly as part of its new wholesale gas market monitoring powers, particularly the use of over-the-counter (OTC) products.

[1] Energy Ministers' Meeting, Summary of measures: Priority reforms for a more secure, resilient and flexible east coast gas market, 2022.

- Participation has grown significantly in each market, particularly from exporters, producers and traders, which has reduced concentration. This means that volumes traded are dispersed between more active participants.
- There are no significant barriers in the spot markets, but administrative complexity and prudential requirements may be barriers to further growth in participation, particularly for smaller participants.
- Growth in participation on the STTMs appears to have led to increasing participation in offering market operator services (MOS). On some pipelines this appears to have put downward pressure on costs, despite rising usage of MOS.
- Changes to ancillary payments and capacity certificates in the DWGM appear to have improved the system, but capacity certificates remain largely untested.
- Growing participation in the spot markets is putting competitive pressure on prices as more varied participant groups are offering gas.
- Participants appear to have varied levels of reliance on net buying in spot markets to meet their demand. Participants with higher net buying can be more exposed to downstream spot market prices, although they can also be hedging price risks.
- The downstream spot markets are supporting arbitrage opportunities, and a variety of participants are using them to move gas to where it is most valued.
- Participants may use spot markets and storage facilities to manage short-term variations in demand for gas-powered generation (GPG) or high electricity prices. The AER intends to investigate the connections between gas and electricity further as part of its Wholesale gas competition report in 2026.

# 2 Background

The AER has regulatory responsibilities to monitor the performance of the east coast wholesale gas market in Queensland, NSW, Victoria, South Australia, Tasmania, the Northern Territory and the ACT. Commencing in May 2024, amendments to the National Gas Law expanded the AER's market monitoring and reporting powers and introduced obligations to include the performance of the wholesale gas markets and the effects of financial risk management products and bilateral trading agreements. With these changes, we are required to monitor and review the performance of the wholesale gas markets, including identifying whether there is effective competition in the market and whether any market features may be detrimental to effective competition or efficiency.[2]

This is our third focus report since receiving expanded market monitoring and reporting responsibilities. This report covers the downstream spot markets – the DWGM and the STTM.

Through this report we intend to examine the role and performance of downstream spot markets in supporting competition and efficiency, specifically considering:

- how participants use the spot markets to adjust long-term contracted positions and allocate gas to where it is needed
- how the spot markets support access to short-term wholesale gas as an alternative to other sources of supply such as gas supply agreements (GSAs).

This is the final focus report in a series of 3 reports focusing on specific facilitated markets and assessing whether they have supported efficiency and competition in the east coast wholesale gas market. The first report looking at the Day Ahead Auction (DAA) was released in October 2024 and the second report on the Gas Supply Hub (GSH) was released in December 2024. Beyond developing the AER's understanding of these specific markets, these focus reports identify and analyse key issues relevant to the biennial wholesale gas competition report, which will be published in 2026.

## 2.1 Downstream spot markets

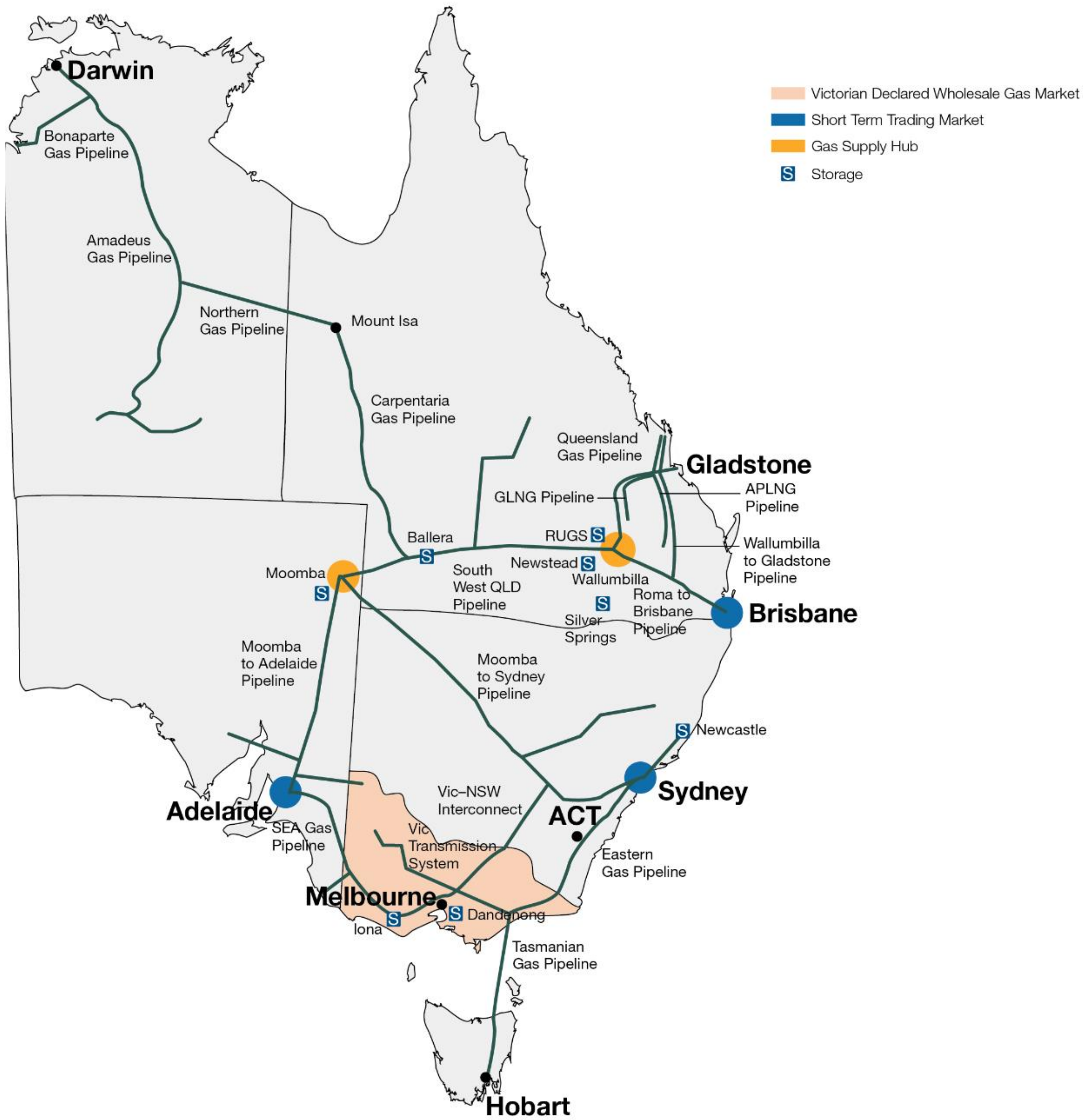
There are 4 downstream spot markets in the east coast gas market: the DWGM in Victoria and 3 STTMs in Sydney, Adelaide and Brisbane. These markets allow participants to manage differences between their longer-term contracted positions and their immediate gas needs. For instance, a retailer might buy additional gas beyond what it had contracted to meet its customers' demand on a particular day while a producer might need to sell off any excess production. Downstream spot markets may also be used to trade gas in lieu of agreeing to a long-term contract.

The DWGM was established in 1999 and is connected to the Victorian Transmission System (VTS), which distributes gas throughout Victoria. The STTM is comprised of 3 hubs in Adelaide, Brisbane and Sydney, which were established in 2010 and 2011. Figure 1

2 National Gas Law, section 30AC.

illustrates how the downstream spot markets connect to the major transmission and distribution pipelines.

### Figure 1 Eastern markets, pipelines and storage




Source: AER analysis using Natural Gas Services Bulletin Board data.

Buyers of gas that want to supply their gas into Victoria, or via the VTS, are required to participate in the DWGM, while buyers that want to supply gas into, or via, Adelaide, Brisbane or Sydney must participate in the STTMs. This means a market participant that sources gas upstream for their own demand downstream (i.e. doesn't wish to trade additional gas on the spot markets) must still schedule this gas into the spot market distribution system by matching the quantity of their bids and offers.

The DWGM and STTMs are operated by AEMO. It is mandatory for participants trading gas in these regions to be registered and provide AEMO all supply and demand forecasting for each market. This provides AEMO with the information required to operate the markets efficiently, including in the event of a pipeline capacity constraint.

However, the markets have separate rules and price setting approaches, which are outlined in this chapter.

## 2.2 Purpose of downstream spot markets

The wholesale supply and transportation of gas on the east coast is primarily facilitated through bilaterally negotiated gas supply and transportation contracts. However, these contracts tend to be based on long-term arrangements and gas users are often unable to perfectly predict their future gas demand when entering such contracts.

This means that surpluses and shortfalls in a user’s supply to meet their actual demand on a given day often arise (they are contractually obligated to buy more (or less) gas than they need on a given day).

The downstream spot markets were introduced to resolve these imbalances on an intra-day or day-ahead basis, improve the efficiency of gas trading by complementing long-term contractual arrangements and provide participants with a way to trade gas at major demand centres on a short-term basis with clear and structured parameters.

The establishment of the downstream spot markets promoted the efficient use of gas by:

- Providing participants with a way to trade gas at major demand centres on a short-term basis with clear and structured parameters.
- Improving the efficiency of gas trading by managing differences between forecasted supply and actual demand to mitigate short-term gas shortfalls.
- Providing an efficient and transparent pricing system.
- Providing price signals indicating where pipeline investment or new gas supply might be needed.
- Centralising trade in locations connected to infrastructure that enables participants to trade between locations & find arbitrage opportunities.
- Encouraging retail contestability and the diversity of supply and upstream competition.
- Creating a systematic approach to gas supply and system security.

Since the DWGM and STTMs were established, changes have been made to improve the operation of the spot markets in response to the development of the LNG export industry and the growing importance of short-term trading due to GSAs being offered at higher prices, for shorter durations and with more restrictions.[3] In particular, government has sought to reform wholesale gas markets across the east coast to improve the efficiency of gas trading and support more effective management of price and volume risk in spot markets.

3 AEMC, East Coast Wholesale Gas Market and Pipeline Frameworks Review, Australian Energy Market Commission, July 2016, p. i.

The development of these markets has been outlined in Table 1.

### Table 1 Downstream spot market developments

| Year | Problem identified | Solution achieved |
|---|---|---|
| **2004** | When the DWGM was founded in 1999, the price was determined daily post trading occurring (ex-post).<br>In 2004, a review by AEMO's predecessor found that the ex-post approach did not allow the market to respond to changing conditions during the day.[4] | As a result, since 2007 the DWGM's market price is now set in advance of each trading period based on scheduled bids and offers (ex-ante). Intra-day price movements can now signal to participants adjustments that are necessary based on evolving conditions. |
| **2013** | A consultant report from K Lowe Consulting raised issues with inconsistencies with market price cap and cumulative price threshold levels[5] between the DWGM and the STTM.[6] | AEMO has since lowered the DWGM's cumulative price threshold from $3,700 to $1,800 in 2014 and then again to $1,400 in 2020. The DWGM's market price cap has not been changed.[7] |
| **2015–17** | Considering increasing LNG export demand and the pipeline network becoming more interconnected, the Council of Australian Governments Energy Council requested the AEMC review the east coast facilitated gas markets in 2015. The resulting reports drew on findings and recommendations from several similar reviews published in the preceding years.[8] One of these 3 reports focused on the DWGM[9] and noted the following issues:<br>• Wholesale gas market was overly complicated and confusing for participants, primarily due to the 3 different markets (the DWGM, STTM | The AEMC made a series of short-term recommendations for the DWGM and STTM:<br>• harmonise gas days across the DWGM and STTM, so that the commencement of spot market operations aligned<br>• amended the NGL to allow any party to propose rule changes to the DWGM instead of just AEMO and state/territory governments<br>• abolish congestion uplift charges on the DWGM and instead incorporate physical constraints directly into the market price |

4 Victorian Gas Market Pricing and Balancing Review – Recommendations to Government, VENCorp, 30 June 2004.

5 Cumulative prices on the STTM and DWGM are running totals of prices over the previous 7 days. If the cumulative price exceeds the threshold, then the market enters an 'administered price state' in which prices are capped at $40.

6 K Lowe Consulting, Gas Market Scoping Study, a report for the AEMC, July 2013.

7 The DWGM's price cap is $800/GJ, whereas the STTM's price cap is $400/GJ.

8 AEMC, East Coast Wholesale Gas Market and Pipeline Frameworks Review, Australian Energy Market Commission, July 2016.

9 AEMC, Review of the Declared Wholesale Gas Market, Australian Energy Market Commission, July 2017.

| Year | Problem identified | Solution achieved |
|---|---|---|
| | and GSH) each using different rules and terminologies.<br>• Neither the DWGM nor the STTM provided a meaningful reference price. The AEMC found that the DWGM's prices did not incorporate the significant additional costs imposed by uplift payments and that the STTM's hubs being located at the end of long supply chains limited their liquidity and capacity for growth. | • replace the Authorised Maximum Daily Quantity system for prioritising capacity allocation with tradable capacity certificates. |

As noted in Table 1, by 2020 all AEMC recommendations were actioned, except two:

1. **Introducing a forward trading exchange for gas on the DWGM, like in the GSH**. This exchange would have allowed participants in the DWGM to agree to trade gas days, weeks or months ahead of its actual transportation and delivery. It was thought that this would allow those participants to better manage their risk and exposure to pricing. However, the AEMC determined in 2019 that increased use of gas futures on the Australian Securities Exchange (ASX) was fulfilling a similar role and so establishing another exchange would be an unnecessary cost.
2. **A long-term vision of spot markets being consolidated into 2 northern and southern hubs.** Under this framework, the existing GSH trading locations would be consolidated into a single northern hub and the DWGM would be reformed to follow the same market design, becoming the southern hub. These changes were proposed to be implemented from 2020 onwards. However, the AEMC instead concluded that it was 'too soon' for more substantial reforms of the wholesale gas market structure while shorter-term reforms were still being implemented.[10]

### 2.2.1 Differences between the DWGM and STTMs

The primary difference between the DWGM and the STTMs is their respective market access approaches.

The DWGM uses a market carriage approach, where access to the relevant pipeline's (the VTS) capacity is open to all participants. No participants have firm rights to pre-determined or guaranteed access. Instead, access to the pipeline is allocated dynamically by AEMO, which also operates the VTS.[11] This model is similar to how the National Electricity Market (NEM) operates. The STTMs use a contract carriage approach, which means service providers, rather than AEMO, control the allocation of access to the relevant pipeline's capacity.

The main differences between the DWGM and the STTMs are summarised in Table 2.

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10 AEMC, 2020 Biennial review into liquidity in wholesale and gas pipeline trading markets, Australian Energy Market Commission, July 2020.

11 The owner of the VTS is APA, but AEMO operates the pipeline.

**Table 2 Differences in the design of the downstream spot markets**

| Factor | DWGM | STTMs |
| --- | --- | --- |
| **Location** | Victoria | Adelaide, Brisbane and Sydney |
| **Market access** | Market carriage model where AEMO manages pipeline capacity into the market (no firm capacity rights) | Contract carriage model where pipelines and participants manage contracts for capacity into the spot market |
| **Timing** | Operates on an intra-day basis<br>Higher market parameters (i.e. price caps) | Operates on a day-ahead basis.<br>Lower market parameters (i.e. price caps) |
| **Balancing mechanisms** | AEMO balances the DWGM through payments and charges for deviation quantities. Ancillary payments may also arise where gas is scheduled out of merit order to meet supply requirements and/or manage system security. | AEMO can manage gas volumes through deviation charges, market schedule variation penalties, MOS and contingency gas mechanism |

## 2.3 Operation of the markets

AEMO operates the STTMs and DWGM in different manners as set out by the National Gas Rules (NGR). The following sections describe the specific approaches established for each market.

### 2.3.1 Declared wholesale gas market (DWGM)

AEMO operates the DWGM on an intra-day basis, meaning participants may submit offers and bids during the gas day for the following 5 pricing periods:

| 6 am to 10 am | 10 am to 2 pm | 2 pm to 6 pm | 6 pm to 10 pm | 10 pm to 6 am |
| --- | --- | --- | --- | --- |

However, AEMO also publishes provisional schedules before the gas day. These provisional schedules provide signals to the market on the price and supply and demand for the gas day.

Participants must submit their offers (injection bids) to sell and bids to buy (withdrawal bids) to AEMO[12] at least one hour before the commencement of the gas day (at 6 am). If required, participants may submit revised offers and bids at least one hour before the commencement of a pricing period. Participants must specify:

12 In the DWGM, offers to sell gas are referred to as 'injection bids' while bids to buy gas are called 'withdrawal bids'.

1. the quantity of gas they expect to inject and withdraw over the day
2. the price for the injections and withdrawals[13]
3. hourly demand forecasts for uncontrollable withdrawals
4. the relevant capacity certificate, which provides rights for transportation within each zone of the VTS.

Subject to pipeline capacity, AEMO matches offers and bids by scheduling injections and withdrawals in a way that minimises price and then determines a clearing price. AEMO then produces:

**The operating schedule**

AEMO produces the operating schedule at the start of the gas day to set out the hourly injections and withdrawals. AEMO uses modelling to create the schedules based on participants' offers and bids, weather conditions and other relevant information such as supply constraints. The schedule is revised for each pricing period.

**The pricing schedule**

The pricing schedule sets out the forward looking (ex-ante) price for each pricing period. The prices are determined using a bid stack that schedules lower priced gas ahead of higher-priced gas. The pricing schedule ignores any pipeline constraints so may differ from the operating schedule.

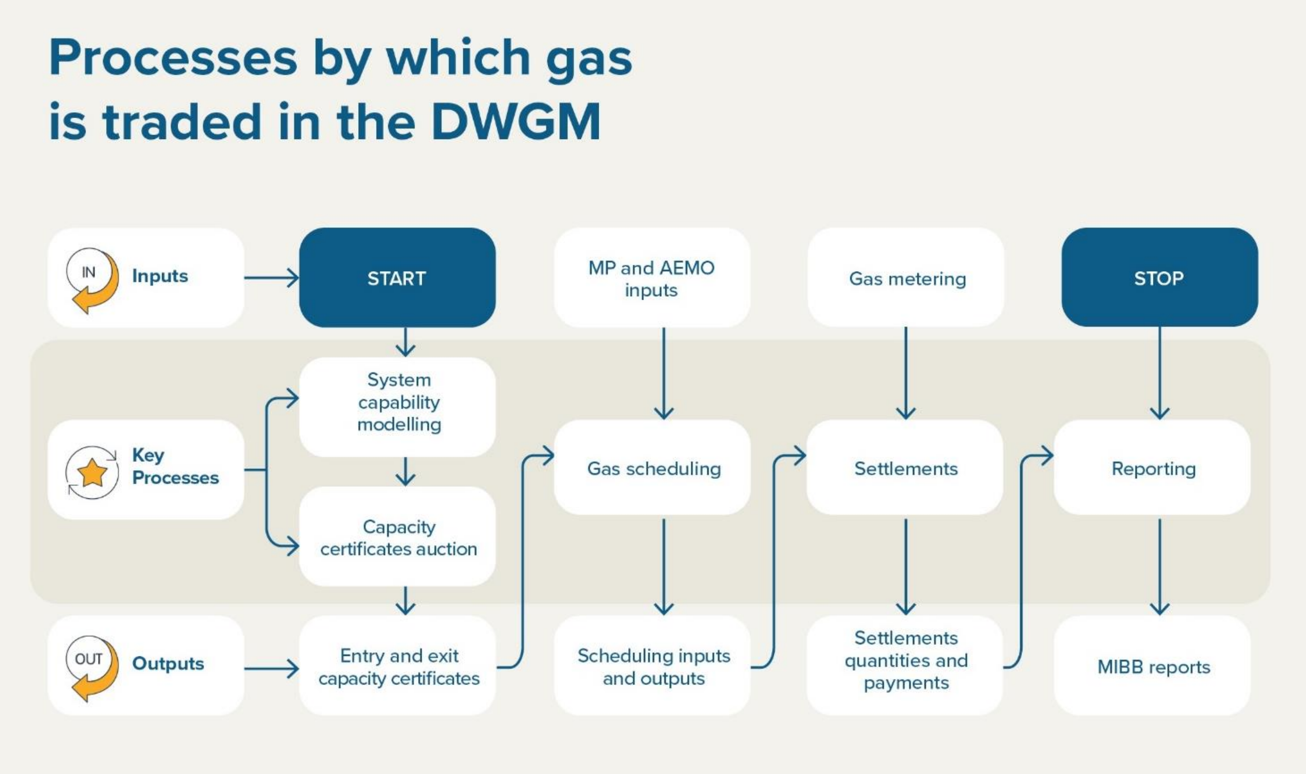
Constraints in the gas pipeline system sometimes result in the operating schedule differing from the pricing schedule, as the lower-priced gas cannot physically reach the appropriate destination. In such a situation, AEMO can schedule additional gas injections above the clearing price. AEMO provides additional payment to the participants that inject the additional gas, referred to as ancillary payments. These payments are drawn from charges levied against the market and/or individual participants responsible for causing the deviation.

Market participants may also deviate from the operating schedules. For instance, a retailer may need to withdraw more gas than planned due to unexpected demand. These participants incur deviation payments, which are based on the size of the deviation and the market price in the subsequent schedule. The resulting imbalance in gas volumes is settled by AEMO purchasing or selling gas at market price through its linepack account. Any surplus or deficit in the linepack account at the end of the gas day is apportioned to participants proportionate to their total withdrawals, setting the account back to zero.

The DWGM is settled on a net basis, which means that participants are only paid or pay for the difference between actual injections and actual withdrawals plus the daily sum of any deviation payments, ancillary payments or linepack account payments incurred.

13 Prices can range from $0/GJ (price floor) to $800/GJ (price cap) and cover gas as well as pipeline transport.

This process is summarised below:




Note: MP refers to market participants. MIBB reports refers to Market Information Bulletin Board reports.

Further details on the DWGM can be found in AEMO's technical guide to the DWGM.

### 2.3.2 Short Term Trading Markets (STTM)

AEMO operates the STTM on a day-ahead basis, meaning that participants submit offers and bids the day before the relevant gas day. However, AEMO also publishes provisional schedules 2 and 3 days before the relevant gas day. These provisional schedules provide signals to the market on the price and supply and demand for the gas day.

This process is summarised below:[14]

## Process by which gas is traded on the STTMs

**AEMO publishes a provisional schedule 3 days before the gas day**
This schedule is based on provisional bids and offers from participants, and capacity information from service providers.

**AEMO publishes a provisional schedule 2 days before the gas day**
This schedule is based on provisional bids and offers from participants.

**Participants submit offers and bids the day before the gas day**
Participants must have the trading rights for the volume of gas they offer and/or bid. The offers and bids must also be between $0/GJ (price floor) and $400/GJ (price cap).

**Close of trade**
11.30am in Sydney, Adelaide and Brisbane
The pipeline schedule sets out the quantities of gas that are scheduled to flow over the next day for each participant.

**AEMO determines the price for the gas day**
AEMO use a bid stack that schedules lower priced gas ahead of higher priced.

**AEMO publishes the final schedule 1 day before the gas day**
The schedule sets out the gas to be supplied and taken by each participant on the gas day.

**Participants nominate gas to be transported**
Each participant nominates the volume of gas it requires to be transported by the relevant service provider to the hub on the gas day.

**Service providers prepare a pipeline schedule**
The pipeline schedule sets out the quantities of gas that are scheduled to flow over the next day for each participant.

**Gas day commences**
6 am in Adelaide, Brisbane and Sydney

**AEMO Publication**
Allocations are submitted by facility operators and AEMO publishes the ex-post schedule.

Gas is sold and bought according to AEMO's forward-looking market schedule and price (ex-ante). If participants deviate from the schedule, AEMO can levy deviation charges.[15]

Key mechanisms to manage deviations efficiently include:

1. **Market schedule variations (MSV)**, which allow participants to reduce deviations from their ex-ante market schedule by either informing AEMO of intra-day renominations, or by transferring differences in supply and demand which net out with the differences of another participant.[16]
2. **Market operator services (MOS)**, which are used by AEMO to manage deviations between schedule and actual gas flows – this involves drawing on gas made available by pipeline service providers and/or participants to balance deviations and ensure adequate pipeline pressures going into the STTM hubs.

The STTM is settled on a net basis at the end of the month and accounts for deviation, variation and capacity charges and credits for MOS and contingency gas. Further details on the STTM can be found in AEMO's technical guide to the STTM.

## 2.4 Our approach

### 2.4.1 Assessment considerations

In assessing the performance of the downstream spot markets, we sought to identify the ways in which they deliver competition or efficiency benefits to the broader east coast gas market. We then assessed whether the current arrangements deliver against those aims. We consider a well-designed downstream spot market can aid efficiency and competition by providing:

- **efficient gas trading –** opportunities to match demand and supply in the short term and options to deliver gas to where it is needed most across major demand centres on the east coast
- **price transparency –** price signals that support price discovery and forward-looking decisions to more efficiently manage gas portfolios
- **access to market –** an accessible platform for new entrants to source gas directly and manage their contracted positions.

14 K Lowe Consulting, Gas Market Scoping Study, a report for the AEMC, July 2013.

15 Deviation charges are based on a graduated penalty table, which uses the market price, a backwards looking (ex-post) imbalance price and any contingency gas prices (discussed below). The imbalance price is what the price would have been if the market schedule was based on actual rather than forecast quantities. The imbalance price is calculated 2 days after the relevant gas day. K Lowe Consultation, Gas Market Scoping Study, a report for the AEMC, July 2013.

16 MSVs are also used to avoid deviation payments when a shipper makes an intra-day nomination arrangement with a pipeline operator.

Assessing whether the spot markets are delivering on these aims, we considered:


Our Wholesale Market Monitoring and Reporting Guidelines[17] provide more information on our general approach to monitoring and reporting on the wholesale gas and electricity markets, including the structure-conduct-performance analytical framework. While we sought to apply this framework where relevant in this report, its application has more use in broader market assessments than in the analysis of the downstream spot markets, which form just one part of those markets.

### 2.4.2 Participant insights

To support our analysis, we contacted a range of participants that had actively participated in the downstream spot markets to seek their views on how well the spot markets support their activities in the wholesale gas markets. We received input from 21 individual participants, representing around one-third of total active market participants. The sample included representatives of each of the 5 participant groups and a mix of participants based on size and level of participation in the spot markets.

[17] AER, Enhanced wholesale market monitoring guideline, Australian Energy Regulator, November 2024.

We asked each participant a standard list of questions. The questions addressed the participants' use of the spot markets and perspectives on liquidity and pricing, accessibility of the markets and usefulness of balancing mechanisms. We also asked for any suggestions on how the spot markets could be improved.

# 3 Liquidity and prices in the downstream spot markets

Liquidity is both a source and product of competition and efficiency in the gas market. Higher volumes and frequency of net trade in the downstream spot markets support efficient and competitive outcomes because they enable participants to more easily trade gas to balance contracted positions, find arbitrage opportunities or source gas directly to support short-term market needs.

Overall, liquidity has grown substantially in the downstream spot markets and prices across downstream spot markets are closely aligned. There appears to be a growing preference for spot trading relative to trade outside the downstream spot markets, which may be increasing participant's exposure to price volatility. Therefore, improving financial product liquidity will be important to support market access by helping them manage the increased risk.

Key findings on liquidity and prices in the spot markets include:

**Substantial growth in liquidity.** Net trade has grown significantly since 2016; however, the market has slowed since the peaks seen in 2021 and 2022.

**Hubs have had varying levels of growth in liquidity.** Sydney, Victoria and Brisbane had significant growth over this time, while Adelaide has only seen some moderate growth.

**Seasonality in total trade is stronger than net trade.** While participants contract larger volumes of gas over winter, net trading over winter varies. This suggests spot markets help participants manage contract positions as seasonal factors vary year to year.

**Efficient arbitrage opportunities are occurring between hubs.** Average spot prices across the DWGM and STTMs tend to be closely aligned, suggesting a liquid market between hubs.

**Trade in DWGM futures has declined in recent years.** Trade in DWGM futures began to grow from 2019 but has been considerably lower in the past 2 years.

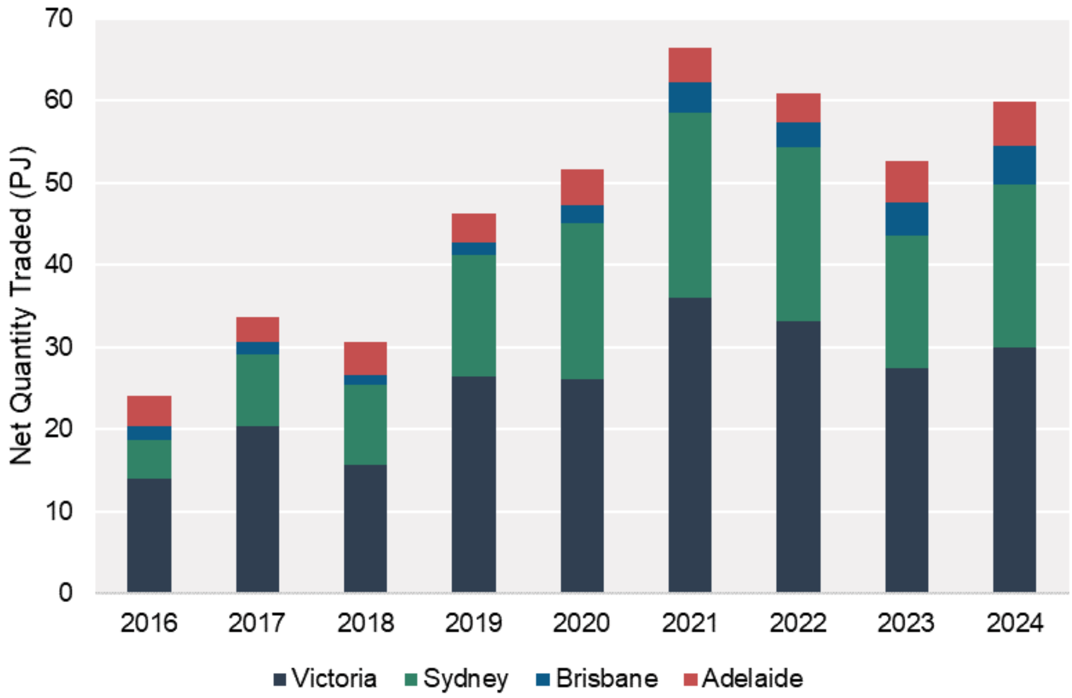
## 3.1 Liquidity has grown in most downstream spot markets

Since 2016 net trade in the downstream spot markets has grown substantially (Figure 2). Despite some easing from the record trade experienced in 2021 and 2022, the volume remains almost double the levels observed in 2018.

Looking at trade in the individual hubs, we have observed:

- Victoria and Sydney are the largest trading hubs by volume and both have experienced significant growth since 2016.
- Brisbane and Adelaide are considerably smaller hubs by trade volume. While Brisbane is the smallest hub, it has experienced significant growth compared with Adelaide and in recent years has been trading similar volumes to Adelaide.

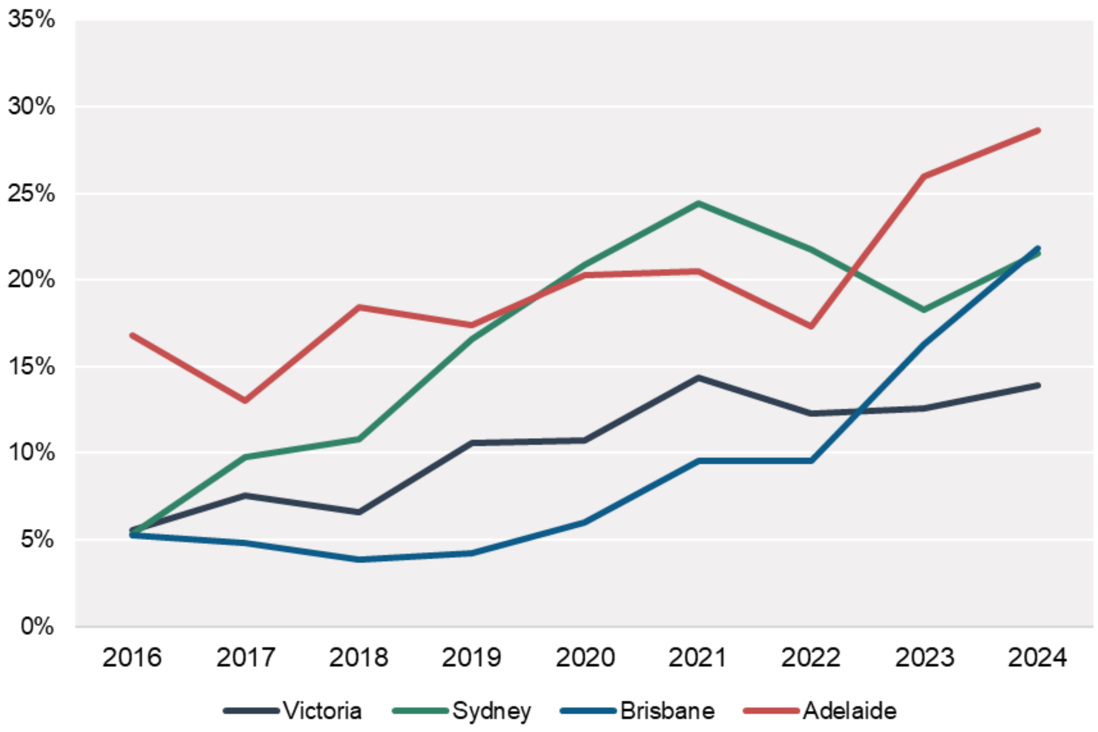
**Figure 2 Net buying by hub location, 1 January 2016 to December 2024**




Note: Trade in the Victorian DWGM and Sydney, Adelaide and Brisbane STTMs have been estimated by netting scheduled buy quantities for each trading participant.
Source: AER analysis of DWGM and STTM data.

Growth in net trade can be an outcome of growth in total demand because the level of balancing required by participants would increase proportionately for deviations in larger volumes. However, the proportion of net demand to total demand has also increased across all hubs, which suggests a higher level of reliance on trading within the spot markets by participants (Figure 3). For Victoria, Brisbane and Adelaide, this shift in recent years is partly due to a combination of growth in net trade and declining total demand.

**Figure 3 Net demand as a proportion of total demand by hub location, 1 January 2016 to 31 December 2024**




Source: AER analysis of DWGM and STTM data.

While growth in net demand proportional to growth in total demand is desirable for balancing contracted demand and supply, growth beyond this suggests structural changes in the market towards a greater preference for spot trading. While this could reflect an efficient response to market conditions, it could also reflect a growing reliance on spot trading due to other barriers in the broader gas market. Potential drivers for the growth in spot market trading include:

1. a shift in preferences among some market participants towards flexible and shorter-term arrangements, including a higher reliance on spot market gas, particularly among smaller retailers (discussed further in chapter 6)
2. increased trading among participants engaged in more opportunistic trading behaviour – for instance, greater participation from exporters and producers and traders (discussed further in chapter 6)
3. an increase in the volume of gas sold under short-term GSAs and the spot markets after the Gas Price Order was introduced by the Australian Government in late 2022[18]
4. use of financial products that provide options to hedge against spot market volatility and can be settled through net positions (discussed further below).

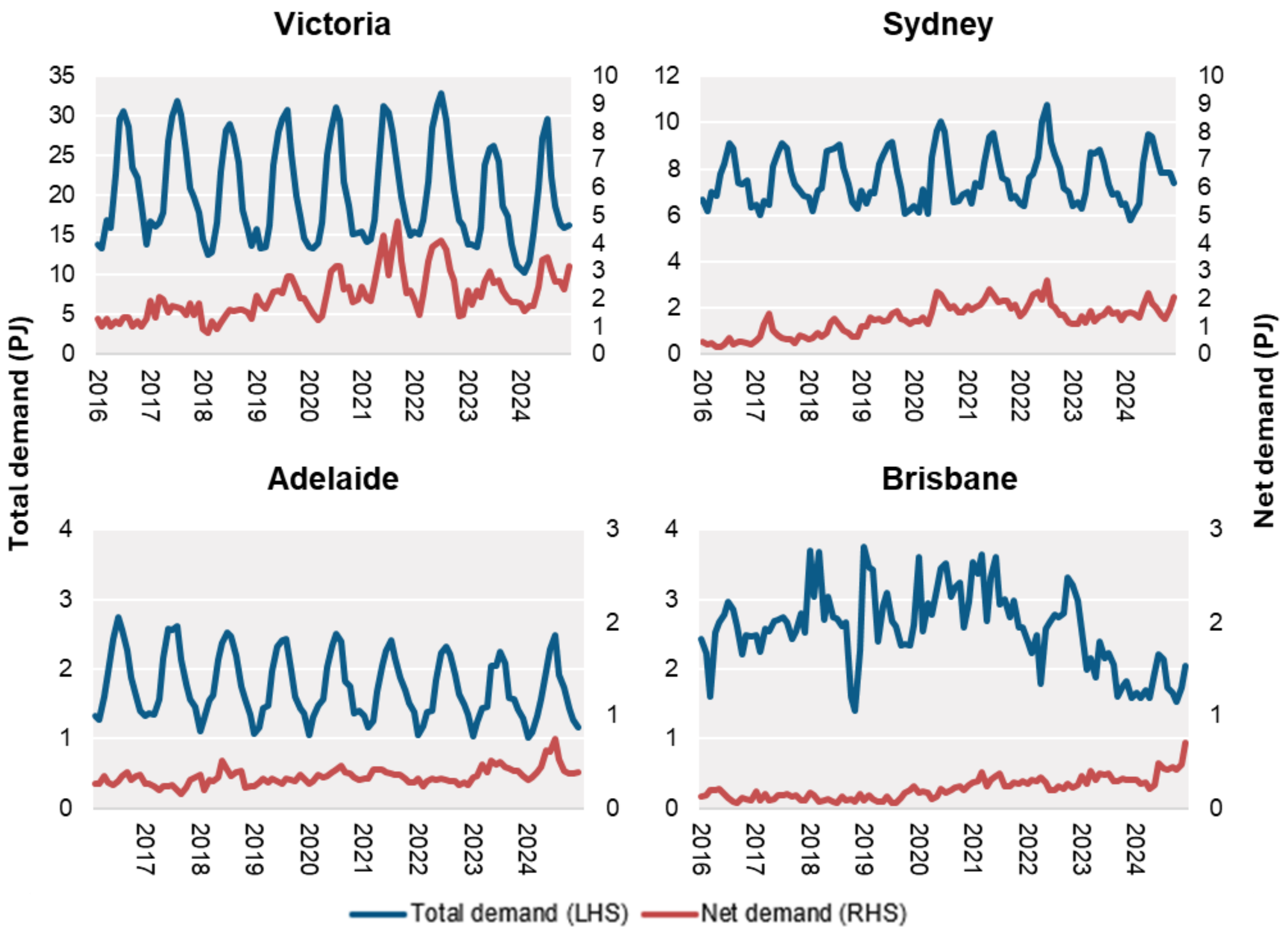
18 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, pp. 12, 54.

## 3.2 Seasonality in total trade is stronger than net trade

Patterns of total demand for gas in the downstream spot markets are highly seasonal. Residential gas demand is a major driver of overall domestic demand and is typically highest in winter, largely due to gas heating in regions connected to the downstream spot markets.

In most markets, gas demand is higher in winter than in summer, due to the increased use of gas for heating in colder weather (Figure 4). Brisbane does not feature this pattern, which is likely due to its warmer climate – gas is primarily used for GPG and industrial use rather than seasonal heating.

**Figure 4 Monthly total trade and net trade by hub, 1 January 2016 to 31 December 2024**




Source: AER analysis of DWGM and STTM data.

Seasonality in net trading is weaker in comparison to total trade in Victoria, Sydney and Adelaide. This suggests participants are contracting larger volumes over winter to meet increased demand. While higher levels of net trading generally occur in winter months, the strength of this relationship varies year to year. This likely reflects participants managing their contracted positions as seasonal factors vary each year.

There are also relatively strong levels of net trade occurring in summer months. This may be partly due to the presence of industrials on the spot markets, who tend to be net buyers and have demand year-round for production processes.

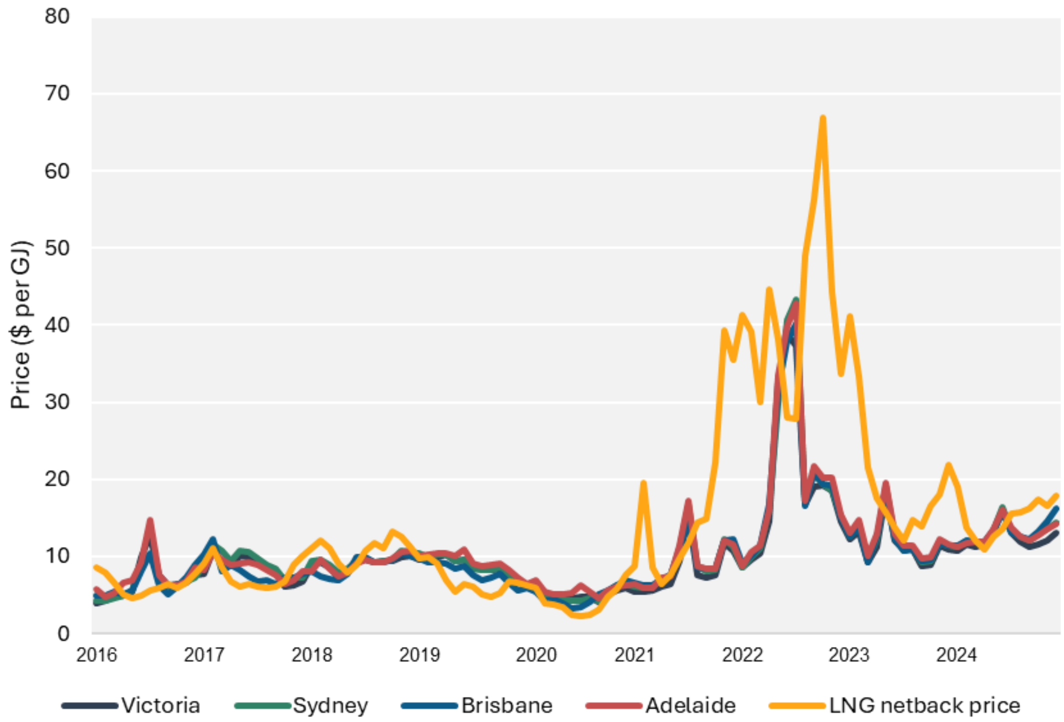
Strong net trade in summer months also suggests the spot markets play a role facilitating flows of gas from the south to the north in summer in response to southern supply surpluses and elevated export demand. This was particularly evident in late 2024 when net trade spiked in Victoria, Sydney and Brisbane. This occurred alongside record levels of gas flowing north as high production and low demand in the south combined with high LNG export and gas-powered generation demand in Queensland, which created a significant gap in prices between north and south spot markets.[19]

## 3.3 Spot market prices are closely aligned but less correlated with international prices

In a liquid and competitive wholesale gas market, prices should be efficient and reflect underlying costs (i.e. the costs to produce and transport gas). This means that significant differences in prices between markets should not last long, as participants would be incentivised to buy gas where it is cheaper and transport it to sell where it is more expensive, causing the prices to move closer together.

Comparing prices across spot markets suggests the markets are liquid, with all trading hubs following highly correlated monthly patterns (Figure 5). This correlation has also been observed between prices in upstream and downstream facilitated markets.[20]

**Figure 5 Average monthly spot market prices and LNG netback, 1 January 2016 to 31 December 2024**




Source: AER analysis of DWGM and STTM data and ACCC LNG netback data

19 AER, Wholesale markets quarterly – Q4 2024, Australian Energy Regulator, January 2025.

20 AER, Focus Report: Gas Supply Hub, Australian Energy Regulator, December 2024.

Spot prices are influenced by an interplay of international and domestic factors. Domestically, spot prices tend to shift in response to retail and gas-powered generation demand, southern production levels and supply constraints due to maintenance or pipeline outages. Domestic prices also tend to be correlated with international prices – for instance, when the LNG netback price is above the domestic price, producers have an incentive to export uncontracted gas rather than supply it to the domestic market, which puts upward pressure on domestic prices. Most of the year, southern demand is not reliant on gas from LNG exporters in the north; however, the correlation is more expected during winter when elevated southern demand requires gas sourced from Queensland.

Since 2020 several significant market events have impacted the price of downstream spot gas, including:

- lower prices during the COVID-19 pandemic, driven partly by reduced LNG demand and lower international prices
- international volatility in 2022 from the war in Ukraine and global energy crisis – during this time LNG netback prices were significantly above domestic prices, but domestic prices momentarily converged and went above LNG netback price in mid-2022, due to a combination of pressure from international prices and higher gas-powered generation leading into winter[21]
- introduction of the Gas Price Order by government in late 2022 and the subsequent mandatory Gas Market Code, which included a price cap that does not apply to downstream spot markets – this may have influenced a shift to shorter-term trades that are exempt and put some downward pressure on prices.

The daily margin between the highest and lowest spot market prices has narrowed significantly over time, from an annual average of $2.70 in 2016 to $1.40 in 2024 (Figure 6). In recent years, Brisbane and Adelaide have tended to have the highest daily prices. This likely reflects the smaller and less liquid trade on these markets, which reduces the incentive for participants to arbitrage these higher-price opportunities. It may also reflect transportation constraints into these markets, which reduces competitive pressure on prices (discussed further in chapter 6).

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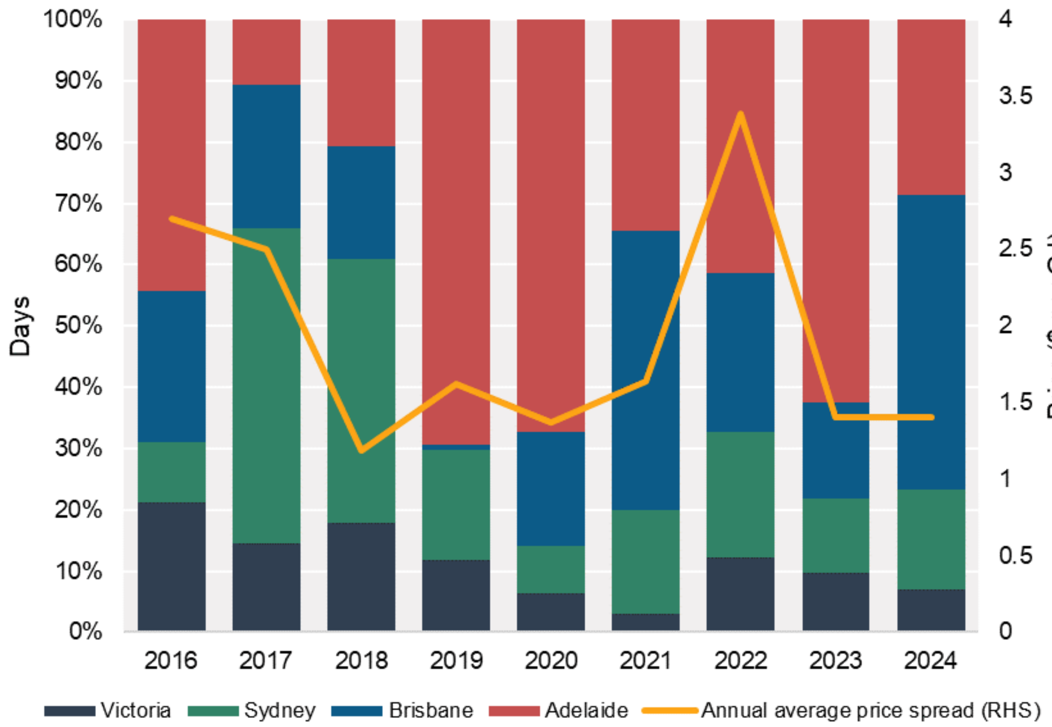
[21] AER, State of the Energy Market 2023, Australian Energy Regulator, October 2023, p. 157.

**Figure 6 Proportion of days each spot market had the highest price and annual average price spread between spot markets, 1 January 2016 to 31 December 2024**




Source: AER analysis of DWGM and STTM data.
Note: The proportion represents the number of times a particular hub had the highest price compared to the other three locations on a given day. This only includes days where a single hub has the highest price and excludes days where two or more hubs share the highest price.

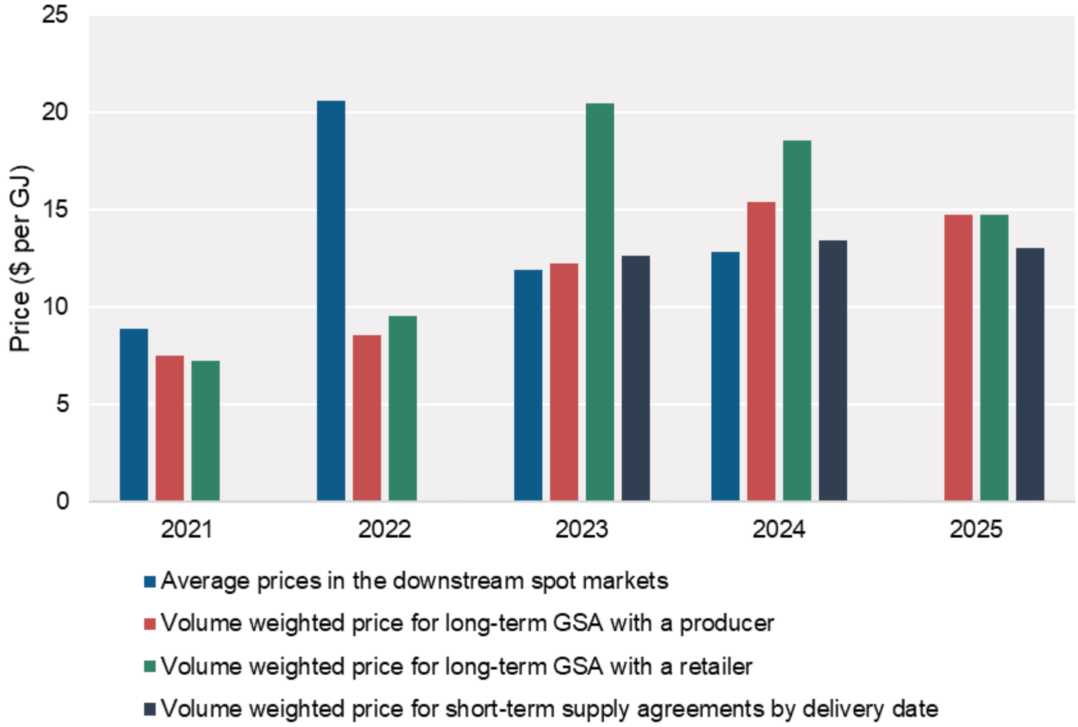
## 3.4 Spot market prices have fallen below contract prices

Long-term GSAs offer predictable pricing structures and guaranteed volumes, providing buyers with supply security and producers with revenue certainty. In contrast, gas procured on both upstream and downstream spot markets is traded on a short-term basis, often daily, with prices subject to near real-time supply and demand dynamics.

While spot market gas and short-term supply contracts offer greater flexibility and can be advantageous during periods of low prices or changing operational needs, they expose buyers to greater price volatility and potential supply risks, especially during periods of market tightness or infrastructure constraints.

For example, spot prices were above contract prices in 2021 and 2022, when there was significant international volatility and increased domestic demand (Figure 7). Spot prices settled back down below contract prices in 2023, but both spot and contract gas prices remain elevated. Prices in wholesale gas and electricity markets have remained elevated compared to historical levels, as they continue to subside from the high prices in 2022. In the gas markets, continued elevation of prices is likely in part due to the ongoing pressures of high international prices and tight domestic supply and demand.

### Figure 7 Comparison of annual average ECGM spot prices, STTM supply prices and GSA price agreed in year immediately preceding supply years 2021 to 2025




Note: East coast average spot prices are calculated by averaging across 4 markets of the 3 daily STTM prices and the Victorian price is the average daily weighted imbalance price. VWA prices for long-term GSAs are sourced from the ACCC Gas Inquiry. All contracts are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. The GSAs in this analysis have an execution date that is within 1 year of commencement of the supply year, GSA prices for 2025 supply only covered 6 months of data. Brent and JKM linked prices for 2021–23 are based on historical prices while prices for 2024–25 use forecast prices. CPI linked prices are estimated for 2024–25.[22] VWA price for short-term supply contracts is sourced from Bulletin Board data and is a volume-weighted average based on contracts that directly supply gas to the 3 STTMs and all the DWGM injection points and is up to date as at 8 April 2025.
Source: AER analysis of DWGM, STTM, Bulletin Board and ACCC data.

Price dynamics between long-term and short-term gas can play a major role in the structure of the gas markets and the level of exposure of participants to spot prices. Before 2021, spot prices were significantly below contract prices, leading to greater interest from participants, particularly industrial participants and retailers, to source cheaper gas from downstream spot markets.[23]

Despite the price volatility experienced in the market over 2021 and 2022, the Australian Competition and Consumer Commission's (ACCC) Gas Inquiry found that lower uptake of long-term GSAs has persisted and there has been greater uptake of short-term contracts. The ACCC also noted that higher GSA prices have led buyers to become more reliant on

22 ACCC, Gas inquiry 2017–2030, interim report, December 2024, Australian Competition and Consumer Commission, p. 37.

23 AER, Wholesale markets quarterly – Q3 2020, Australian Energy Regulator, p. 57.

procuring gas through the facilitated markets, including the downstream spot markets, and this is exposing them to greater physical and financial risk.[24]

Prices for long-term GSAs with retailers dropped in 2024 and they were slightly below prices of long-term GSAs with producers in 2025. While participants may now be more comfortable sourcing a higher proportion of their portfolio through spot markets, some may rebalance towards more firm capacity if prices for these firm GSAs decline further.

## 3.5 Financial products are being used but liquidity remains low

While liquidity growth on the spot markets provides participants additional flexibility in managing short-term market dynamics, spot market trade can expose participants to price volatility. Financial products can help participants manage risk by providing mechanisms to hedge against price volatility and allow participants that do not have access to the physical market to take a financial position. Financial products also provide a useful reference price to guide future investment and supply decisions.

Several financial derivative products are available for trading over the spot markets:

- ASX Victorian wholesale gas futures: Contracts listed on the ASX on a quarterly basis out to 2.5 years, with a lot size of 100 gigajoules per day over the calendar quarter. They are cash-settled against the average of the beginning of day (6 am) price over the calendar quarter.
- OTC financial derivatives: Participants can also trade OTC products bilaterally and may use the services of a broker to facilitate this.

ASX and OTC financial products offer different benefits to participants:

- ASX products are standardised, transparent to the wider market and include centralised clearing services and daily prudential requirements that reduce a participant’s exposure to counterparty credit risks. However, this offers less flexibility, and prudential requirements may become too onerous for some participants.
- OTC financial products provide greater flexibility in contract terms and volume compared with ASX products – for example, they could include terms that deal with physical supply constraints due to a gas plant outage. However, trading financial products bilaterally introduces considerable counterparty credit risk and may also disadvantage smaller participants that have less negotiating power.

The DWGM futures product has been available since 2007 but only began trading substantially in 2019. However, liquidity is still generally low, with trade representing around 20% of DWGM net trade on average. Liquidity has declined further since 2022 (Figure 8). While many participants noted that they either traded or used DWGM futures as a reference price, most noted the usefulness was constrained by low liquidity.

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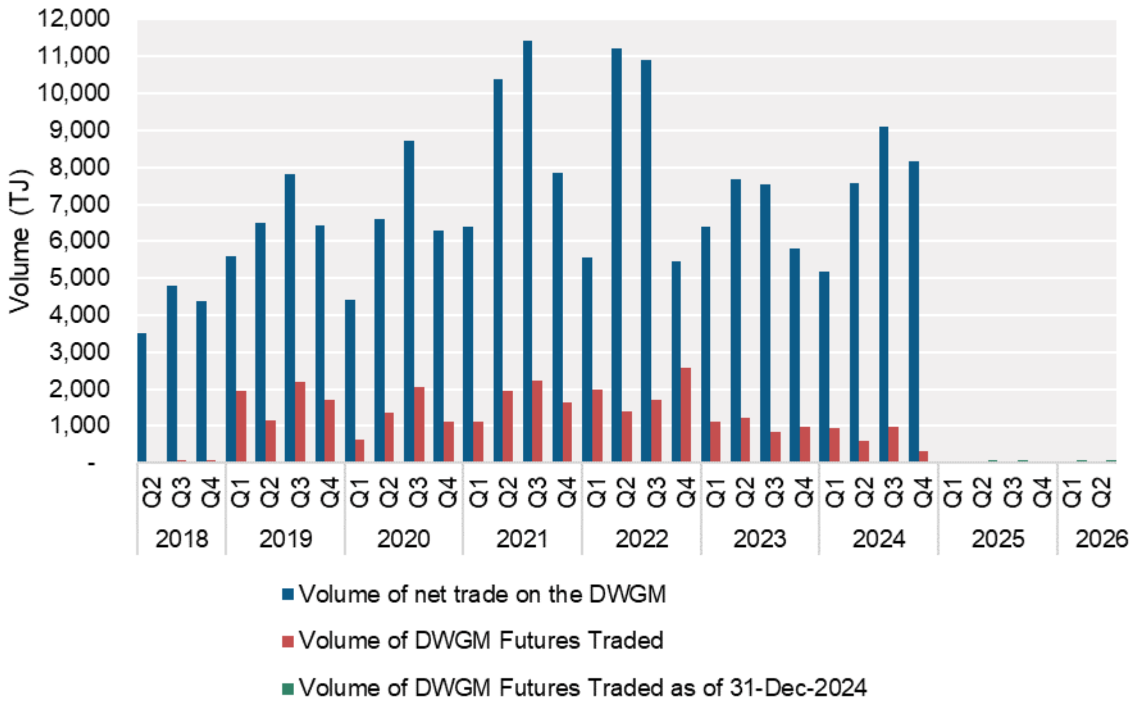
24 ACCC, Gas inquiry 2017–2030, interim report, December 2024, Australian Competition and Consumer Commission, pp. 7, 39.

### Figure 8 DWGM futures traded and net trade



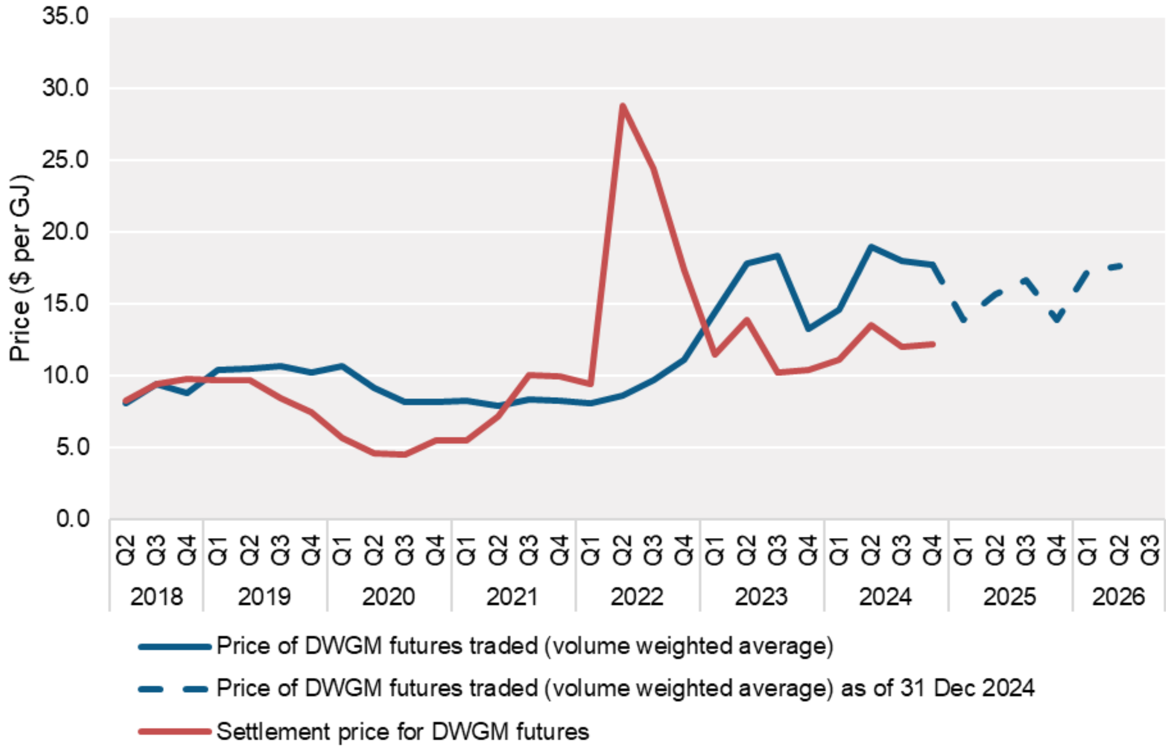

Source: AER analysis of DWGM and ASX data.

Some larger participants explained they did not trade financial products because they did not have internal processes established or a financial licence to trade ASX or OTC financial products. This may partly explain why liquidity of DWGM futures has been low. However, participants did not suggest this was a hard barrier to accessing the financial market and so participation in financial products may improve if the benefit outweighs the costs.

Several participants reported using OTC products and suggested the market for these products has been growing, particularly around the Sydney STTM. The AER does not currently have data on OTC products to assess these trends and overall liquidity in more detail. However, the AER intends to collect and report on this financial information as part of its new wholesale gas market monitoring powers.

The decline in trade in DWGM futures since 2022 may have also led to growth in OTC products in Victoria – some participants suggested the credit requirements for sellers of DWGM futures became too onerous during the price volatility observed at that time.

### Figure 9 DWGM futures traded price and final settlement price




Note: Price of DWGM futures traded is a volume-weighted price of all the trades in the respective quarter.
Source: AER analysis of ASX data.

Participants also suggested that liquidity of ASX futures could be further improved if the product was offered on a monthly, rather than quarterly, basis. This would align the product with the recently introduced ASX Wallumbilla Futures product physically delivered on the Gas Supply Hub at Wallumbilla and would allow participants to more accurately manage price risks caused by seasonal variations. The ASX is strongly considering this proposal, along with a proposal to introduce an ASX futures product for the Sydney STTM, and has been consulting with participants on these products.

Lower liquidity in DWGM futures may reflect the lower maturity of the gas financial market compared with the electricity financial market. Additional financial products may help the gas market mature further by improving the usefulness and accessibility of the financial market.

# 4 Access and participation in the downstream spot markets

The number of participants making use of the spot markets has grown significantly. This increase largely occurred up until 2020 and participation has remained steady since then.

Our analysis suggests no significant barriers to entry exist in the spot markets and growth in participation has both reduced concentration and increased competitive pressures on spot trading. Nonetheless, participants suggested that administrative complexity and prudential requirements may be barriers to further participation.

Key findings on access and participation include:

**Participation in the spot markets is growing.** The number of participants in each market and the volumes traded by each participant group have increased significantly since 2016.

**More gas is being supplied into the spot markets by different participant groups.** In previous years GPG gentailers supplied most gas into the spot markets. However, over time exporters and producers, traders and industrials have supplied more gas to the spot markets.

**Differences in participation across trading hubs appear to reflect trading strategies rather than barriers to entry.** Most participant groups trade in 2 or more hubs and variation is consistent with each group's trading strategies.

**Concentration has declined as participation has grown.** Concentration measured by HHI has largely been decreasing for net buying and selling in the spot markets. However, across all spot markets the top 3 sellers still account for 40–50% of gas sold.

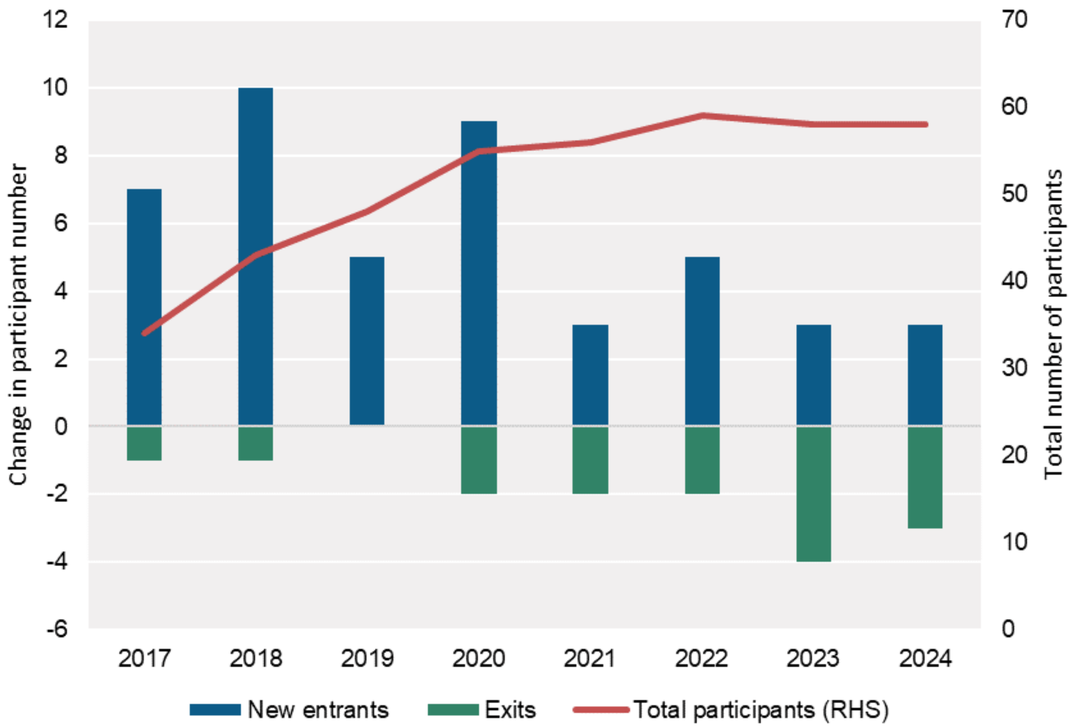
**Administrative complexities and prudential requirements may be barriers to increased participation.** While no major barriers to entry have been identified, some participants have suggested market complexity can be a barrier and prudential requirements may also be constraining further participation in the spot markets.

## 4.1 Participation has grown significantly

Participation in the spot markets has increased significantly since 2016, with the number of participants trading almost doubling from 33 in 2017 to 59 in 2024 (Figure 10). Most growth occurred between 2016 and 2020. Growth in participation during this time was largely driven by new industrial, retailer and trader participants and was likely in part a response to growth in the LNG export industry in Queensland and new opportunities to source wholesale spot gas from large exporters and producers that entered the market around this time.[25]

Since 2020 the spot markets have maintained around 60 participants. There has been a significant number of new entry and exits over that period, primarily industrial and retail users. This has occurred alongside international volatility and domestic supply constraints in the gas markets.

**Figure 10 Number of participants and entry/exits in all spot markets, 1 January 2016 to 31 December 2024**




Note: 'Entry' counted as the number of new participants trading in the market each year that had not previously been involved. 'Exit' counted as the number of participants that ceased trading and had not resumed by December 2024. Exits also capture mergers/buyouts of some participants.
Source: AER analysis of DWGM and STTM data.

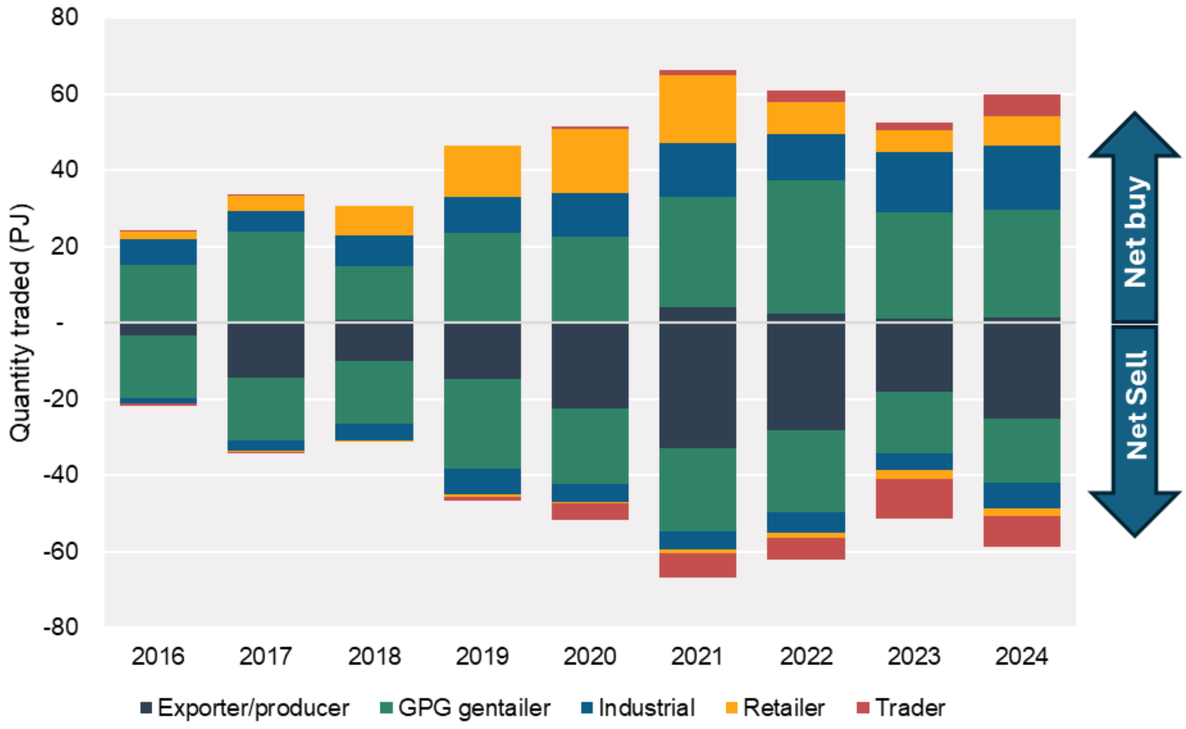
Growth in participation also occurred across individual trading hubs. Like trends observed in net trade (chapter 3), the largest growth in participation occurred in the DWGM and Sydney STTM. This likely reflects the size of total demand in those markets relative to Adelaide and Brisbane.

25 AER, Wholesale markets quarterly – Q3 2020, Australian Energy Regulator.

All participant groups have been trading larger volumes on the spot markets (Figure 11). Notable trends include:

- **Several different participant groups now supply gas into the spot markets.** In earlier years, the market was dominated by GPG gentailers, that were likely balancing their contracted positions. This has changed over time as exporters and producers, traders and industrials supply more gas to the market.
- **Retailers and industrial participants buy more gas on the spot markets.** Significant growth in retailer net buying occurred up until 2021, largely driven by Weston Energy. However, Weston Energy lost its gas retailer authorisation in May 2022,[26] leading to retailer net buying reducing by almost half between 2021 and 2022. Since then, retailers have continued to enter the market and trade larger volumes. Industrial participants have also increased buying, but this has been relatively steady despite the volatility of 2021 and 2022. In consultations, a few industrial participants suggested price volatility and concern about future supply shortfalls had prompted a pivot in portfolios back towards the contract market.
- **Traders increased trading on the spot markets.** Since 2020 traders have been trading larger amounts on the spot markets. This likely reflects a mix of greater arbitrage opportunities and traders operating on behalf of smaller participants. So far, no traders have left the market since entering.

**Figure 11 Net traded gas in all spot markets, 1 January 2016 to 31 December 2024**



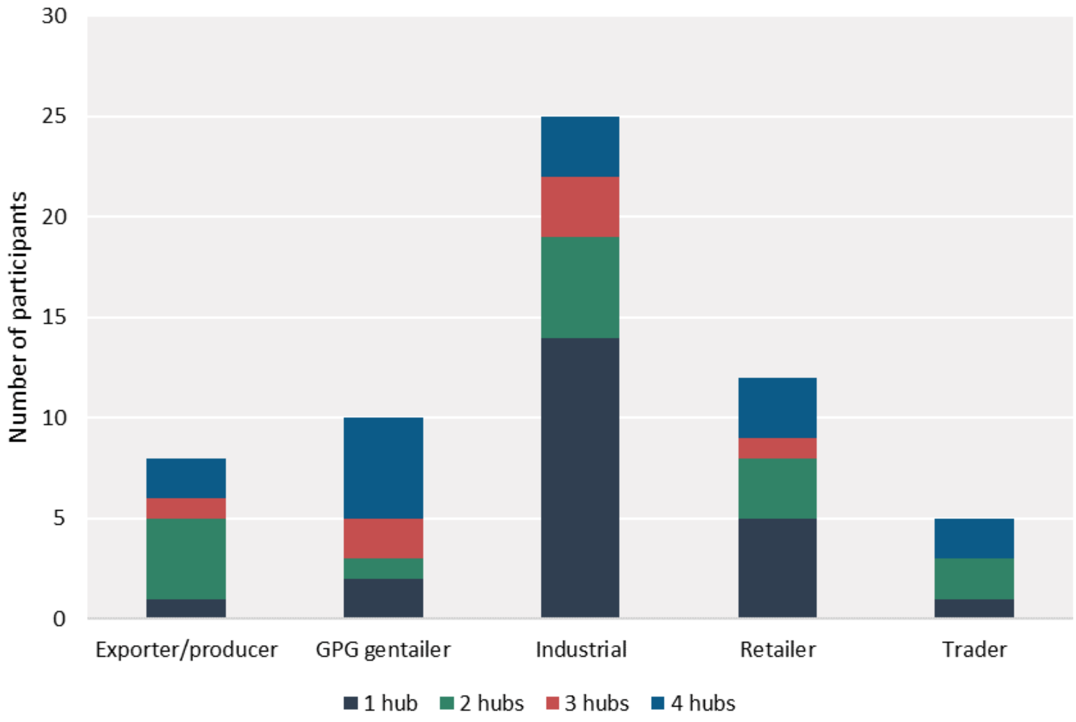

Source: AER analysis of DWGM and STTM data.

[26] AER, Weston Energy Pty Ltd - authorised gas retailer - revoked, Australian Energy Regulator, May 2022.

## 4.2 Participation across hubs likely reflects different business strategies

Participant groups differ in the spot markets they trade in across the east coast (Figure 12). The spread of participant groups across trading hubs does not indicate any significant barriers to entry that exist between these hubs; instead, it most likely reflects differences in business strategies between groups. Around 60% of participants operate in at least 2 hubs, usually the DWGM and Sydney STTM, likely due to their proximity to large downstream demand centres.

**Figure 12 Number of trading hubs in which participant groups were active during 2024**




Source: AER analysis of DWGM and STTM data.

GPG gentailers and traders are comparatively more likely to participate in 3 or 4 trading hubs. This may reflect their use of the spot markets to manage positions to meet retail and gas-powered generation demand at multiple downstream markets.

Industrial participants and retailers are more likely to participate in only a single hub. For retail participants, this hub is commonly the DWGM because Victoria has larger retail gas demand than other markets on the east coast. Industrial participants' choice of hub is more varied, appearing to be largely determined by the location of their facilities.

Most exporters and producers participate in 2 hubs, usually the DWGM and Sydney STTM, although some exporters and producers have expanded to the Adelaide and Brisbane markets as well. The focus on these 2 larger demand centres is probably due to the large volumes of gas exporters and producers seek to trade, in part to manage variance in their production. A few exporters and producers also noted that individual hubs could not always absorb the excess supply they had available.

## 4.3 Market concentration is declining

To determine participant concentration, we have considered their proportion of net buying and selling and estimated the Herfindahl-Hirschman Index (HHI). The HHI of the spot markets is derived from calculating the sum of the squared share of net buying and selling for all participants that year. HHI can range from zero (in a market with many firms with similar market share) to 10,000 for a monopoly.

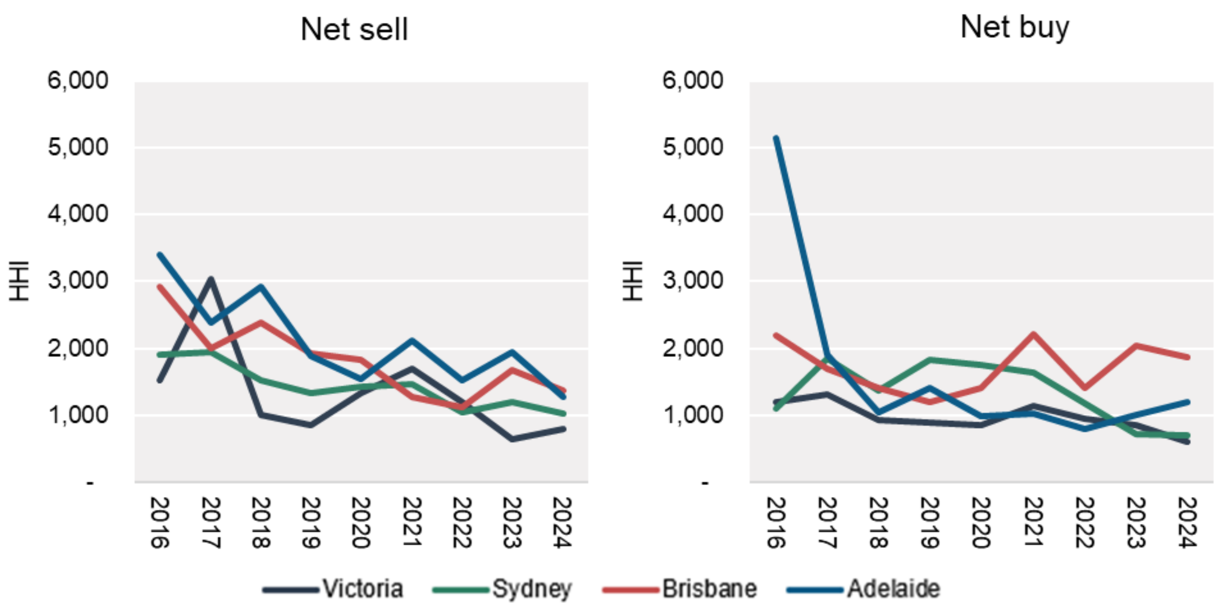
HHI is a commonly used measure of market concentration in competition analysis. However, in the context of the spot markets this measure should be interpreted with care because participants primarily use the spot markets to adjust their contracted position. Most participants are not solely reliant on the spot markets to directly buy or sell gas. Furthermore, net trade is determined by the level of gas that has been allocated at the clearing price, which means high levels of concentration in spot market selling may hide that additional gas could have been provided by other participants at a small marginal increase in price.

Nevertheless, HHI can still provide a useful measure of market concentration and insight as to how concentration is changing over time. Lower levels of concentration among buyers and sellers reduces the risk of liquidity shocks and gives participants greater certainty in using spot markets to trade physical gas.

Concentration in net buying and selling is relatively volatile year to year, but concentration has declined over time across all hubs as participation has increased (Figure 13). Given the size and growth of the Victorian and Sydney markets, there has been lower levels of concentration in recent years than in Brisbane and Adelaide. Between 2019 and 2021, Sydney saw a brief increase in concentration among gas buyers, which was almost entirely driven by the activity of Weston Energy. However, the market share of the top 3 buyers in Sydney decreased over the same period and participation generally increased. Hence, there was a sharp fall in concentration in 2022 after Weston Energy left the spot markets.

Although more participants use the spot markets, most participants typically only trade small amounts and the volume remains concentrated among a few large players. In 2024, the top 3 sellers still accounted for 40% to 50% of total volumes supplied across all trading hubs. However, since 2016 the top 3 sellers have often not been the same each year, and have varied from hub to hub, indicating a variety of participants flexibly adjusting their positions in response to broader market dynamics rather than a static market dominated by just a few participants.

**Figure 13 HHI by net trade proportion, 1 January 2016 to 31 December 2024**




Source: AER analysis of DWGM and STTM data.

## 4.4 Administrative complexities and prudential requirements may be barriers to increased participation

In our consultations, many participants referred to the administrative burden of understanding the complex mechanisms and procedures involved in participating in the spot markets as a potential barrier to entry or growth, as well as a general source of frustration and confusion. This includes setting up and operating trading rights and contract registrations, setting up systems to manage forecasts and deviations and understanding balancing mechanisms such as MOS and ancillary payments (chapter 5). On the other hand, some participants noted the complexity of the markets was necessary and inherent to the nature of the east coast gas system. Participants also acknowledged that they had few issues once their systems and processes were established – this was particularly the case for those operating in the markets for a longer period.

To help navigate this complexity, some retailers and industrial users indicated that smaller gas buyers would seek advice and direction from – or even outsource trading entirely to – external parties, such as traders. However, one smaller retailer noted that these services were not always available to buyers with relatively small demand.

A few participants suggested that more information and educational support would be helpful to navigate the complexities of the spot markets, which would be particularly beneficial to smaller players. For instance, it was suggested that participants would better understand and respond to changing market conditions if daily bid stacks and MOS outcomes were presented graphically and/or in an easily digestible format.

Prudential requirements were repeatedly raised by participants as the largest material barrier to further participation, which mirrors feedback we received on the GSH.

Participants suggested that the inability to pool credit requirements across the various facilitated markets, including the downstream spot markets and associated financial products, was administratively cumbersome. Additionally, in some instances they confirmed that this constrained the level of liquidity they could offer into the markets. Several participants mentioned the need to manage significant prudential requirements despite having equal credit and debit positions across multiple spot markets, which effectively gave them a net position of zero with AEMO. Combining prudential requirements across AEMO-facilitated markets has been explored in a previous government review of the east coast gas market and is being progressed.[27]

Some participants also suggested that reallocations, as used in the electricity market, would be a beneficial feature of the prudential system.[28] Reallocations allow a participant to net their prudential requirements in the physical trade against financial positions. In the gas markets, this may be particularly helpful for smaller players that are often more exposed to spot market trade and constrained by their credit requirements. For example, a small retailer entering an OTC derivative contract in Sydney with a large retailer to buy gas could net their financial and physical positions to reduce their credit requirement. This would mean the smaller retailer would only require credit to cover their hedged position while the large retailer would owe AEMO the value of the contract difference.

27 Energy Ministers' Meeting, Summary of measures: Priority reforms for a more secure, resilient and flexible east coast gas market, 2022.

28 AEMO, NEM Reallocations, Australian Energy Market Operator, October 2023.

# 5 Balancing and security mechanisms

To ensure system security and adequate physical flow of gas each day, the downstream spot markets need to balance complex interactions between supply, demand and transportation constraints in the physical trading of gas. To achieve this efficiently, both the STTM hubs and the DWGM have been designed to include mechanisms that ensure gas can be allocated quickly to meet imbalances in the most cost-efficient manner that is also transparent to market participants. These mechanisms incentivise participants to forecast their demand and supply accurately and can help give participants certainty around the price they will pay and receive for gas.

Key findings on balancing and security mechanisms in the spot markets include:

**MOS is largely offered by AGL, Origin and Energy Australia, but in some spot markets there has been significant increase in participation.** This may be putting downward pressure on costs.

**Changes to ancillary payments appear to have provided greater certainty,** but the system remains opaque and can be difficult for some participants to navigate.

**Capacity certificates have improved on the previous system for managing supply constraints on the DWGM.** However, the system remains largely untested and there is uncertainty on the value of these certificates.

## 5.1 Increased participation in MOS has been putting downward pressure on costs

MOS is a daily pipeline balancing service in the STTM hubs. It can take the form of supplying additional gas to the hubs or absorbing excess gas delivered to the hubs – providing balancing gas when deviations occur, ensuring system stability and market efficiency.

MOS offers are made by participants that have contracts with pipeline facilities to ‘park’ gas (on the pipeline) or ‘loan’ gas (from the pipeline). Based on these contracts, 2 types of MOS are offered:

- increase offers that increase flows on a pipeline to a hub
- decrease offers that reduce pipeline flows to a hub.

In the Sydney and Adelaide hubs, one pipeline can provide increase MOS while another provides decrease MOS on the same gas day. This occurrence is known as counteracting MOS (CMOS).

Participants are requested to provide monthly MOS offers ahead of the calendar month commencing and must specify the:

- type of MOS (increase or decrease)
- price (up to $50/GJ)
- quantity
- transmission pipeline.

MOS costs are recouped through payments and charges made by participants that deviated from their forecast schedule to cover a larger proportion of the monthly settlement surplus/shortfall.

MOS provides several benefits to market efficiency in managing demand and supply of gas into the downstream spot markets:

- **Greater transparency.** AEMO calls for offers from participants with eligible contracts to offer MOS each month. This provides a predictable costing scheme that is transparent and allows participants to observe potential MOS costs for the month ahead, and also see AEMO's estimated maximum requirement on an individual gas day for each service provided.
- **Accurate forecasting.** By recouping costs through deviation payments, participants are incentivised to minimise deviations from scheduled quantities, reducing financial risks and improving price signals for all market participants.

Like frequency control ancillary services in the NEM, compared with the total commodity cost of gas being traded in the hubs, MOS typically only accounts for a small proportion of the value of gas in the market (typically below 5% of the commodity cost of net traded quantities).

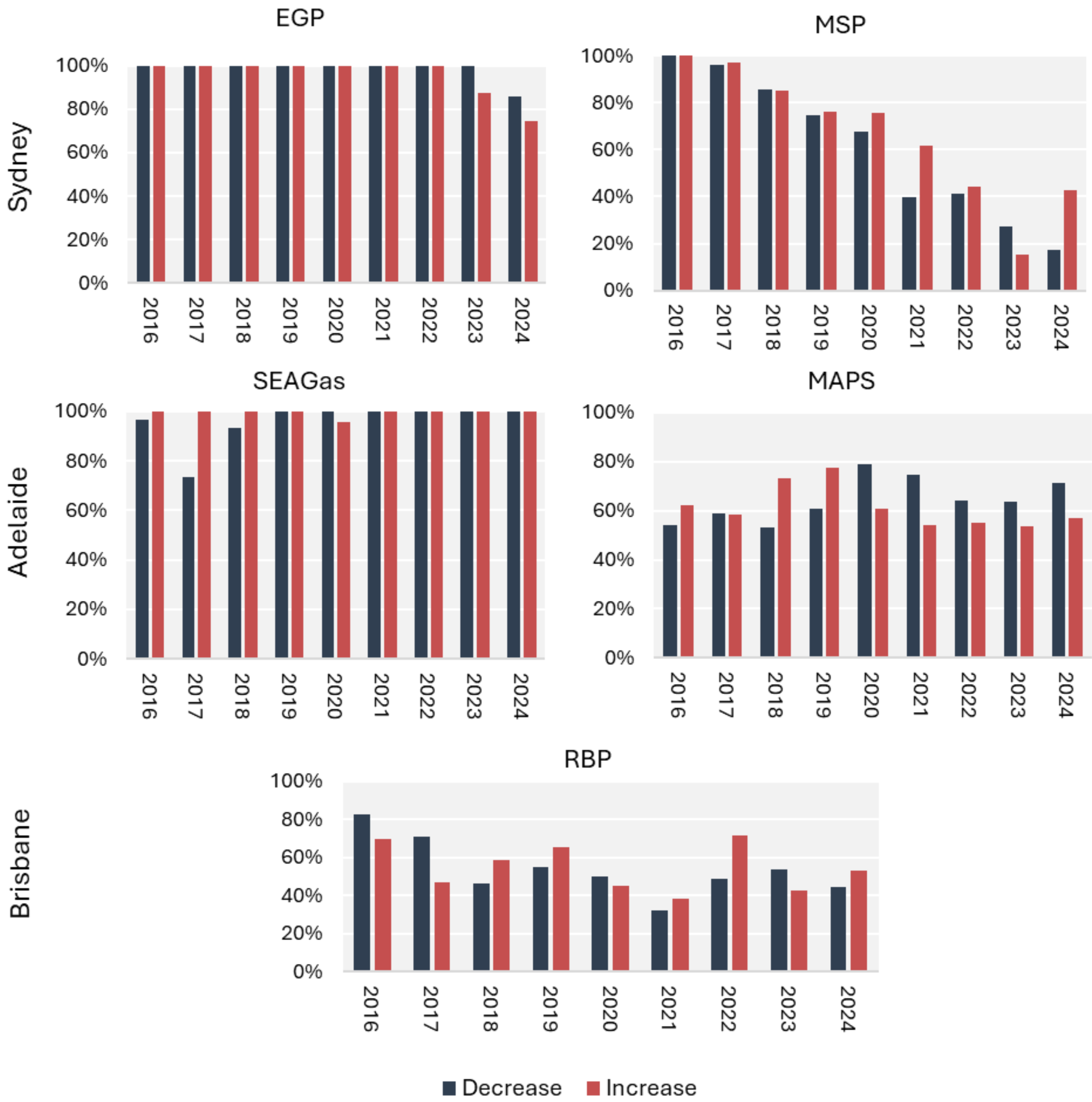
Higher levels of participation in offering MOS can create competition among participants in the prices offered to supply MOS. All things being equal, this should reduce MOS costs. Three large retailers have historically supplied MOS in the STTMs – AGL, Origin and Energy Australia. However, with rising participation in the spot markets since 2016, participation in providing MOS has generally increased over time. The proportion of MOS allocated by the 3 largest retailers has fallen across several pipeline facilities (Figure 14). Further increases in participation have also been observed across 2023 and 2024, with some relatively new market entrants, such as traders, starting to provide increase and decrease services.

For each region:

- **Sydney:** MOS services can be provided on the Moomba to Sydney Pipeline (MSP) and Eastern Gas Pipeline (EGP), pipelines that connect to the Sydney STTM. Participation in MOS on the MSP has grown substantially from 3 participants offering MOS in 2016 to 8 in December 2024. Beyond the 3 large retailers, all participant groups were offering MOS on the MSP in December 2024 – 2 GPG gentailers (Alinta and Shell), one industrial (Visy) and 2 traders (Eastern Energy and SGMT). The EGP has had less growth in participation, with MOS largely provided by the 3 large retailers. However, in the past 2 years MOS has also been offered by Shell and Eastern Energy.

- **Adelaide:** MOS can be provided on the SEAGas pipeline and Moomba to Adelaide Pipeline System (MAPS), which connect to the Adelaide STTM. On MAPS, MOS was historically offered largely by the 3 large retailers, an industrial (AB cement) and a gas-powered generator (Pelican Point). However, since 2018 participation has grown and MOS in 2024 is now also being offered by one GPG gentailer (Alinta), one trader (Eastern Energy) and one producer (Beach). On SEAGas, MOS had been offered by 5 participants – the 3 large retailers, one industrial (AB cement) and one gas-powered generator (Pelican Point), but participation has declined and in 2024 only the 3 large retailers offered MOS.
- **Brisbane:** MOS is provided on the Roma to Brisbane Pipeline (RBP) that connects to the Brisbane STTM. Participation in MOS has grown substantially from 4 participants offering MOS in 2016 to 7 in 2024. While AGL and Origin have consistently offered MOS, there have been several exits (Stanwell and Incitec) and several new entrants, including 3 GPG gentailers (Alinta, Shell and CleanCo) and 2 traders (Eastern Energy and SGMT).

**Figure 14 Proportion of MOS increase and decrease services allocated to AGL, Origin and Energy Australia, 1 January 2016 to 31 December 2024**

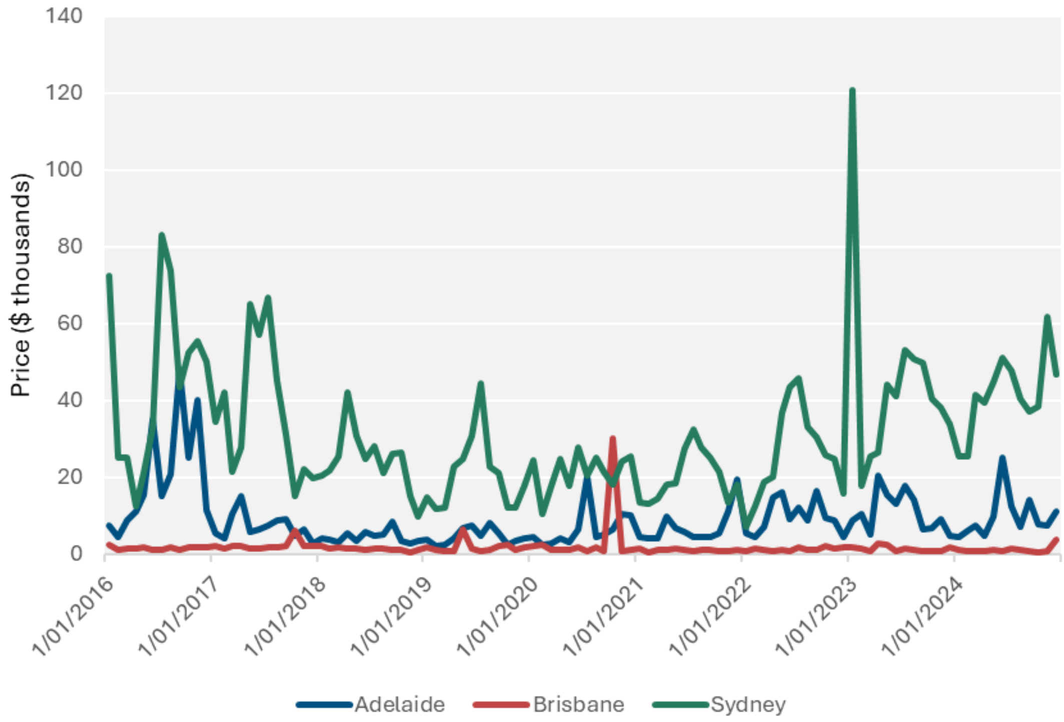



Note: The RBP only counts MOS allocated to AGL and Origin because Energy Australia does not provide MOS on this pipeline.
Source: AER analysis using STTM data.

Increased participation in offering MOS should increase competition and lower the prices offered for MOS. We have observed this increase in competition impacting prices on some pipelines, notably on the MSP. While the price of MOS may be decreasing over time, total MOS costs can still increase if the requirement for MOS increases.

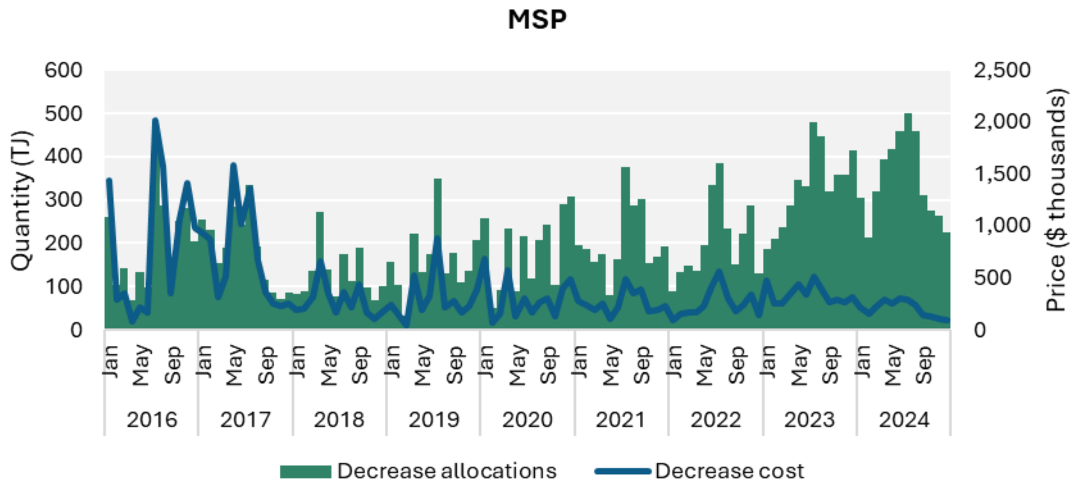
For instance, in Sydney there has been a significant rise in average MOS costs in recent years (Figure 15). This is largely due to increasing MOS on both the EGP and MSP, driven in part by a need for CMOS; however, the higher costs are largely attributable to the EGP (Figure 16). Lower levels of participation in offering MOS on the EGP appear to have contributed to lower levels of available MOS and, therefore, more being allocated from higher-priced offers. In contrast, on the MSP, higher levels of participation have contributed to a larger proportion of available MOS in lower price bands and total MOS costs have been declining even as MOS usage has increased.

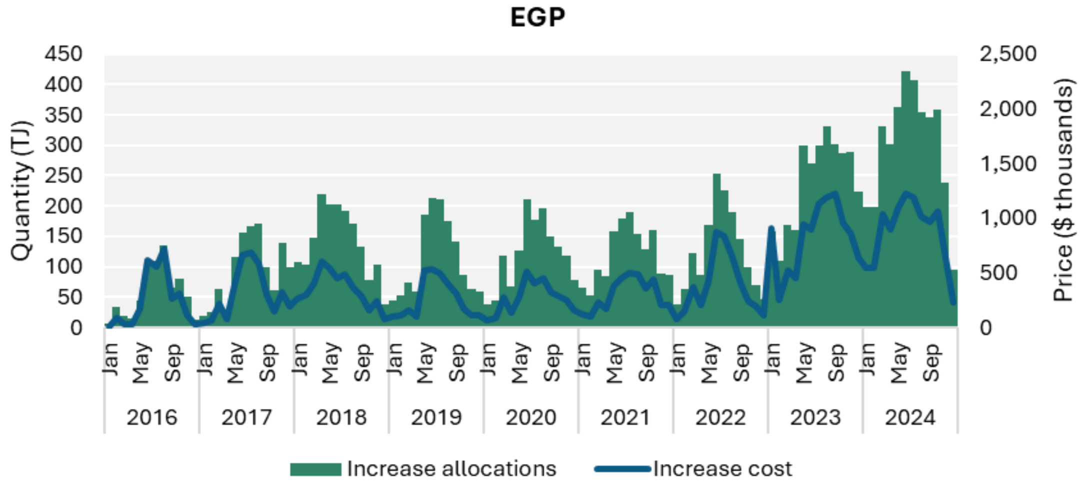
**Figure 15 Average daily MOS payments, 1 January 2016 to 31 December 2024**




Source: AER analysis using STTM data.

### Figure 16 MOS allocations and total cost on the MSP and EGP, 1 January 2016 to 31 December 2024




Source: AER analysis using STTM data.

Lower levels of participation in MOS and higher-priced offers make the STTMs more vulnerable to high-price events when there are significant disruptions in the market. The AER recently reported on 3 significant price variations in the Sydney STTM where MOS service payments exceeded $250,000. A large component of these costs was driven by increased CMOS and higher-priced MOS offers on the EGP compared with the MSP (Box 1).

### Box 1: High-price variations in the Sydney STTMs

MOS service payments in the Sydney STTM exceeded $250,000 three times in November to December 2024. Prior to these events, the significant price variation threshold has been triggered 8 times since 2014, making high-priced MOS events infrequent.

Across the 3 events, high MOS service payments were driven by a range of factors, including unplanned reductions in pressure, market participants over forecasting demand and pipeline renominations.

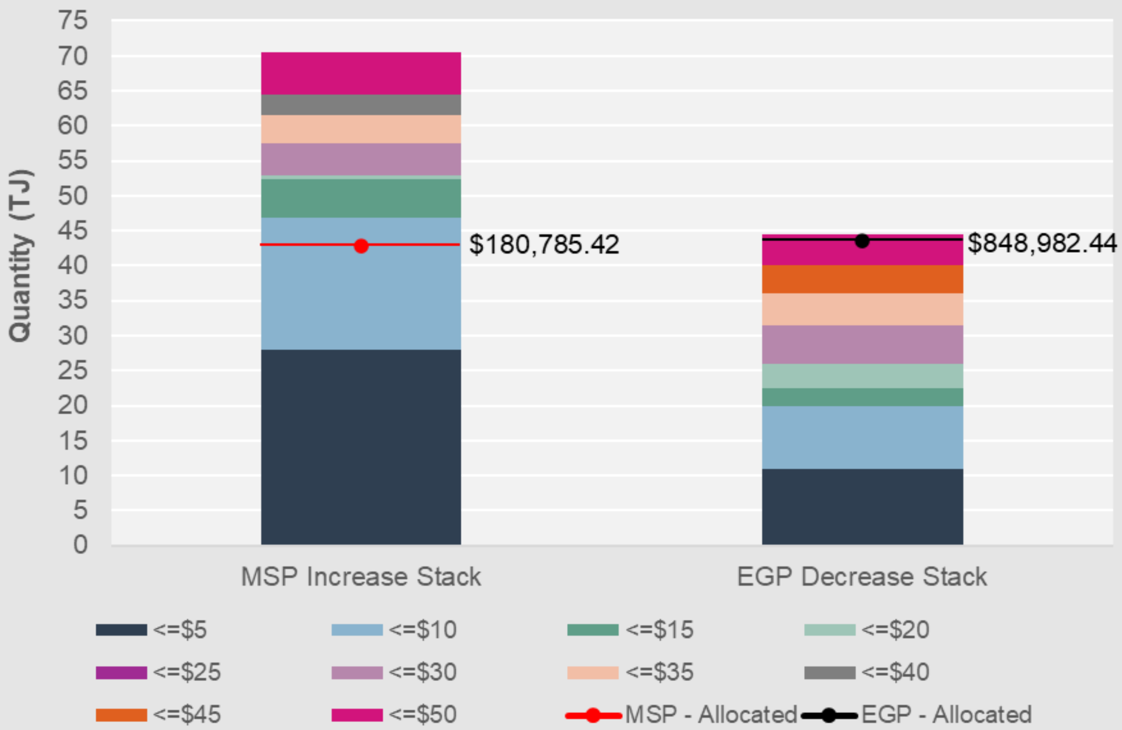
- On 28 November 2024, MOS service payments reached $1,029,767.86. Due to a reduction in operating pressure on the Sydney STTM, CMOS was required with increase

MOS on the MSP (42.8 TJ) being offset by a similar amount of decrease MOS on the EGP (43.6 TJ).

- On 14 December 2024, MOS service payments reached $305,682. Due to participant renominations from the MSP to EGP and a lack of demand to meet the supply, CMOS was required with 23 TJ of increase MOS on the MSP offset by a similar amount of decrease MOS on the EGP (26.5 TJ).
- On 20 December 2024, MOS service payments reached $322,998. This was primarily due to participants over-forecasting demand, leading to 28.8 TJ of decrease MOS on the EGP and 4.03 TJ of decrease MOS on the MSP.

For each of these events, the bulk of the high MOS cost was related to parking gas on the EGP as decrease MOS. Given the EGP receives higher-priced offers to supply MOS, this led to significant cost increases even when a similar quantity of MOS was required on the MSP.

**Figure 17 MOS stacks, allocation requirements and service costs, 28 November 2024**




Source: AER analysis using STTM data.

In consultation with participants, no major issues with the MOS system were identified and it was suggested that the system works effectively to incentivise accurate forecasting. There may be greater burden for deviation management falling on net buyers in the spot market, such as small retailers, that are more exposed to demand variations.

Many noted that participation in providing MOS would require expertise and resources, but it was also noted that once systems were set up it was relatively easy to navigate. Participants that reported providing MOS were typically larger GPG gentailers or producers and it was noted by some that their choice to provide MOS largely depended on whether they had access to park and loan transportation services and whether MOS was complementary to their portfolio.

Some participants that offer MOS noted that monthly offers to provide MOS services were not frequent enough and it would be beneficial if MOS offers could be adjusted more frequently. It was suggested that a more frequent process for offering MOS would allow participants to offer MOS with more accurate information on their market position. As a result, less risk would be priced into their offers, which would lower prices.

## 5.2 Reforms to DWGM balancing mechanisms appear to have improved participant certainty and transparency

On the DWGM, AEMO directly manages deviations in demand and supply due to transport constraints with ancillary payments that are provided to participants that are scheduled to provide additional gas when needed. These payments are provided through several charges known as 'uplift payments' levied against the participant(s) responsible for deviating from their demand forecasts and scheduled quantities (injections and withdrawals).

For instance, during a high-price event in 2017, an unplanned outage at Longford and high demand for gas-powered generation required AEMO to intervene in the market to increase supply and maintain system pressures. This involved AEMO issuing an ad-hoc injection schedule, instructing more expensive gas to be supplied from sources outside of Longford, resulting in ancillary payments made to participants that provided supporting injections of gas supply at higher cost.[29]

Recent reforms to the DWGM included the removal of the congestion uplift payment as part of funding for ancillary payments, leaving 3 categories:

- **DTS SP (transmission service provider) uplift,** which occurs when a transmission constraint is applied by AEMO in an operating schedule where the DTS SP has failed to fulfil its obligations under the service envelope agreement and some or all of the ancillary payments are attributable to the failure.
- **Surprise uplift,** which is allocated to market participants that have not followed their effective demand forecast or scheduling instructions for the preceding scheduling interval or have changed their demand forecast and/or have changed scheduling instructions for the upcoming scheduling horizon.
- **Common uplift,** which occurs where total uplift payments are payable in respect of a gas day and operating schedule and are not fully recovered by other uplift payment categories. The balance of the total uplift payments will be allocated to market participants in proportion to their adjusted withdrawals from the declared transmission system in respect of that gas day.

Congestion uplift charges occurred when a pipeline did not have the capacity to transport sufficient gas even if there was adequate forewarning of supply and demand conditions. Therefore, charges were levied on market participants that were scheduled to withdraw gas in excess of their allocated portion of the physical capacity of the system.

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[29] AER, Significant price variation report: Victorian gas wholesale market: Ancillary Payments, Australian Energy Regulator, 30 November 2017.

The removal of congestion hedge uplift aims to make the price signal cleaner in the DWGM by incorporating congestion hedge uplift into the market price. This allows the market price to reflect a greater proportion of the wholesale price of gas and improve market participants' ability to effectively manage risk.

Participants in consultation were largely supportive of the recent reform to remove congestion hedge uplift payments. They noted the changes had made processes simpler and provided more certainty around short-term dynamics. Despite this, some participants noted that the system overall was still fairly opaque, which made it hard to correctly interpret the cause of changes in prices and ancillary payments.

Reform to the DWGM has also recently included a new capacity certificate system to manage instances when multiple participants have equally priced bids. This capacity certificate system replaced the old authorised Maximum Daily Quantity and Authorised Maximum Daily Quantity credit certificates. Key differences are listed in Table 3.

**Table 3 Key differences and similarities between the old and new regimes**

| Previous Authorised Maximum Daily Quantity regime | Capacity certificates regime |
|---|---|
| • Protection from congestion uplift (burden of paying for managing congestion falls on participants without capacity rights).<br>• Curtailment protection (flow gas when other participants cannot).<br>• Credit certificates impart long-term rights.<br>• Tie-breaking rights. | • Congestion uplift removed for all participants.<br>• No protection from curtailment.<br>• Rights can be acquired for a shorter period, allowing more flexibility. Auctions held at least twice a year.<br>• Tie-breaking rights remain. |

The new system aims to:

- improve the ability of market participants to obtain capacity certificates to manage scheduling risk through tie-breaking benefits
- create a level playing field for all market participants to obtain capacity certificates through primary auctions, which allows them to be allocated to those that value them the most and promotes efficient use of pipeline capacity
- encourage more efficient allocation of pipeline capacity by allowing market participants to buy a set of entry and exit capacity certificates, which gives greater price and volume certainty to their preferred gas transportation pathways
- improve and simplify current arrangements, which may encourage new entrants and promote competition in upstream and downstream markets and inter-regional trade.[30]

The AER has previously investigated the role of capacity certificates as part of the high-price event that occurred in Victoria in June 2024 due to tight supply and high demand

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30 AEMC, DWGM improvement to AMDQ regime, final decision, Australian Energy Market Commission, 12 March 2020.

conditions.[31] Participants reported mixed views on the value of the certificates (for the south-west entry point) and highlighted the rarity of their use. However, it was also noted that shifting reliance on production from Longford to western Victoria may increase their value. A secondary market for these certificates had yet to emerge, with some participants consulted saying they may hold some more than they typically use for option value.

In consultation, several participants noted that capacity certificates appeared to be working well and offered a more transparent and open process than the previous system. However, several participants also noted that the system was complex to understand and manage and estimating prices in the auction can be confusing. Like previous findings from the AER, the value of capacity certificates also appeared unclear to some participants. However, this was largely because, for those participants, the certificates had not been tested by events that warranted them.

The AER will continue to monitor the use of capacity certificates and development of a secondary trading market for the Wholesale gas competition report in 2026.

31 AER, Significant price variation report: 19 & 21 June 2024 High Ancillary Payments Victorian Declared Wholesale Gas Market, Australian Energy Regulator, 21 August 2024.

# 6 How participants use the downstream spot markets

Growing levels of participation, particularly from exporters and producers and traders, appears to be creating competitive pressure on prices in the downstream spot markets. Despite this growing competition, prices have risen considerably in the downstream spot markets in response to tight supply and demand dynamics and international volatility. Participants appear to have varied levels of exposure to spot market prices and ability to hedge against spot price volatility.

A variety of participants can find arbitrage opportunities between spot markets and move gas to where it is most valued. There appears to be some incentives to use spot gas for gas-powered generation, but most participants will use a mix of spot market gas and storage facilities to manage short-term variations in demand for GPG or high electricity prices.

Key findings on participant use of the spot markets include:

**Increased participation has created competitive pressures on gas offers.** GPG gentailers remain the most influential in setting prices across spot markets, but continued growth in participation from exporters and producers and traders, particularly in Victoria and Sydney, appears to have increased competitive pressures.

**Participants vary in the proportion of gas they source directly from the spot markets.** Participants with a larger proportion of net demand to their total demand may be taking on greater spot price risk and would need to use other options to hedge against this.

**Trader activity is increasing, and small price spreads between spot markets suggest significant arbitrage is occurring.** The spot markets appear to be supporting significant arbitrage opportunities for exporters and producers and GPG gentailers, as well as traders. While arbitrage opportunities still exist between markets, on average the price spread is relatively low between hubs.

**Participants may use spot markets and storage facilities to manage short-term variations in demand for GPG or high electricity prices.** The AER intends to investigate the connections between gas and electricity further as part of its Wholesale gas competition report in 2026.

## 6.1 Pricing behaviour

Market participants' bidding behaviour provides valuable insight into competition levels in the spot markets and overall trends contributing to or affecting competitive outcomes. While detailed bidding analysis is outside the scope of this focus report, we have considered 2 measures of seller behaviour in offering gas into the spot markets:

- **Scheduled offer prices** provide an indication of how much gas was offered and scheduled into the downstream spot markets. When gas is offered at $0 it means a participant was effectively happy to take whatever price the market cleared at, while offers above $0 may not be scheduled depending on the clearing price.[32] In a competitive market for trading spot gas, you may expect to see a higher proportion of lower cost marginal offers, as participants looking to trade gas compete for a lower price.
- **Price setting** shows which participant's marginal offer determined the clearing price for gas on that day. This can provide insight into changing behaviour between groups in terms of who is influencing prices. It can also indicate competitive pressure – where multiple participants are setting prices on a given day (measured as price setting above 100%), there will be less opportunity for a single participant to influence the clearing price.

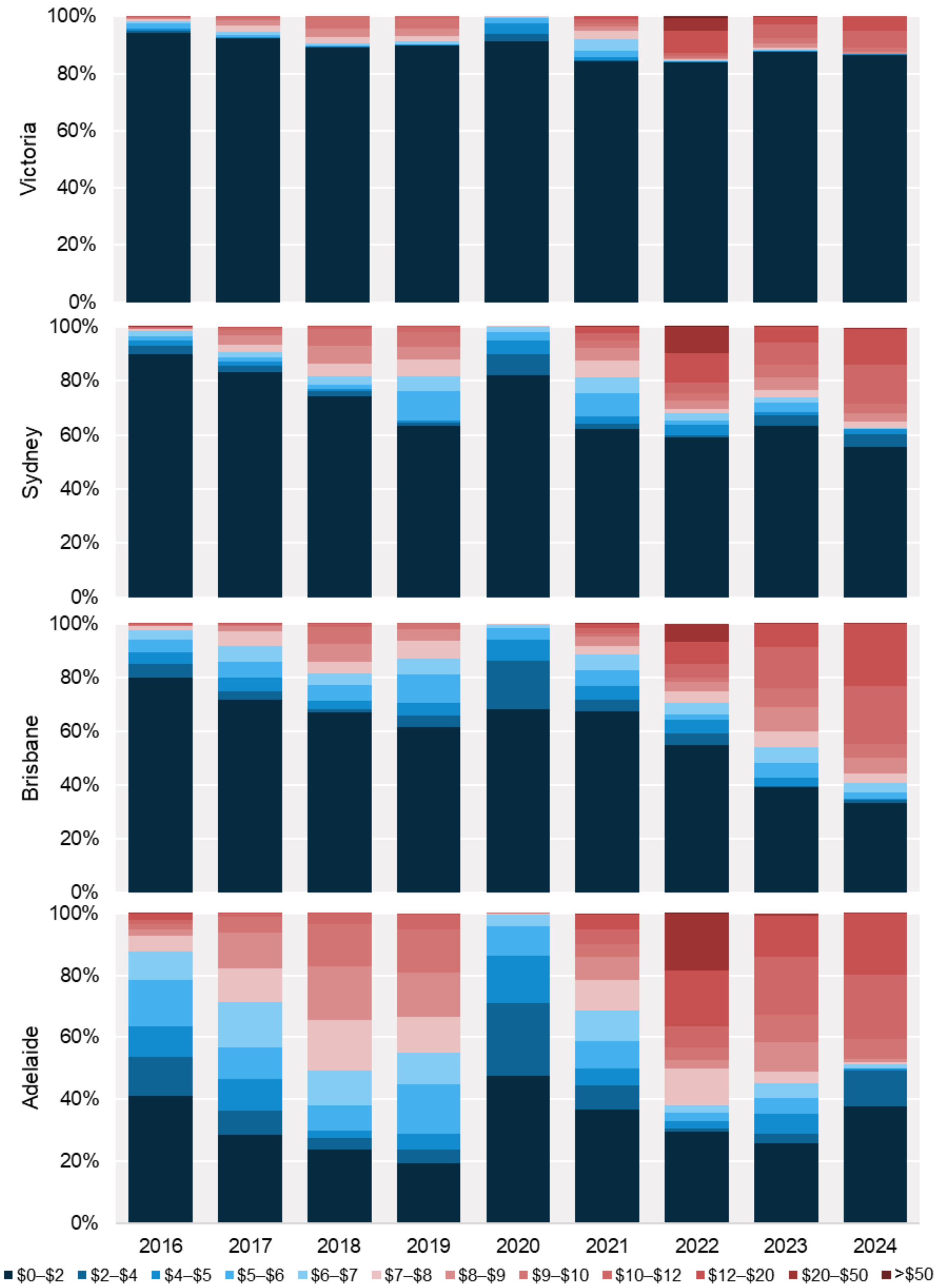
For scheduled offers, there has been a decline in the proportion of $0 offer prices since 2016 in Victoria, Sydney and Brisbane (Figure 18). In Victoria this trend has been less significant, which likely reflects higher volumes of contracted gas flowing into Victoria than in the STTMs, which would be offered at $0 to $2.

Declining $0 scheduled offer prices has partly been driven by the growth of participation from exporters and producers and traders in the spot markets that are offering gas above $0. This may be because these participants are more likely to be operating in the market opportunistically and less likely to have retail or generation demand downstream requiring certain supply. In 2024, around 70% of scheduled offers into the STTMs by exporters and producers were for offers above $0 to $2, while for traders 96% were for offers above $0 to $2. In Sydney this trend has also been driven by a steady decline in GPG gentailer scheduled offers at $0 to $2 and relative increase in offers above this price. In Adelaide this trend has also been driven by a decline in $0 to $2 scheduled offers by GPG gentailers and industrials.

Since the market volatility observed in 2022, there has also been a shift to larger proportions of gas offered above $10 across all downstream spot markets, which is generally consistent with the higher price levels observed across the east coast gas markets compared with prior years.

32 As lower priced offers take priority in the scheduling process, offering at $0 effectively ensures those gas quantities are scheduled unless there is more supply offered at $0 than demand on a given day. This is generally unlikely to occur, as those quantities offered are typically at or below the demand level of the participant(s) offering the supply they need scheduled.

**Figure 18 Scheduled offers by price band, 1 January 2016 to 31 December 2024**




Note: The DWGM price bands were calculated for the 6 am market schedule. The STTM price bands were calculated for the D-1 schedule.
Source: AER analysis of DWGM and STTM data.

Price setting above 100% has grown significantly in all spot markets, likely reflecting higher levels of participation and, as a result, competition in setting the price (Figure 19).

In Victoria, Sydney and Adelaide, this growth is driven by increased participation from traders and exporters and producers and a decline in the level of price setting by GPG gentailers that historically were the most influential in setting prices.

In 2021 and 2022 price setting above 100% was at its peak in Victoria and Sydney, driven in a large part by increased price setting from exporters and producers. This likely reflects peak levels of net trading around this time in response to signficant short-term pressures from high international gas prices, high gas demand in southern markets, high gas-powered generation and supply constraints.[33]

### Figure 19 Price setter by participant group, 1 January 2016 to 31 December 2024


Source: AER analysis of DWGM and STTM data.

Price setting offers by different participant groups can be a sign of increased competition. Our analysis has found that:

- Price setting over 100% has occurred the most in Sydney and in 2024 was at 146%, which may reflect increased competition. Sydney also has the highest levels of price

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33 AER, State of the Energy Market 2022, Australian Energy Regulator, September 2022, p. 124.

setting by traders, exporters and producers. In 2024 traders set prices 39% of the time and exporters and producers set prices 45% of the time.

- Price setting in Victoria has declined since 2023, alongside declining price setting by exporters and producers and comparatively less price setting from traders compared with other regions. In 2024 Victoria had the lowest level of price setting among hubs.
- In Brisbane, exporters and producers and traders have also played a larger role in setting prices in recent years, while in Adelaide, GPG gentailers remain the most influential.

## 6.2 Exposure to spot prices

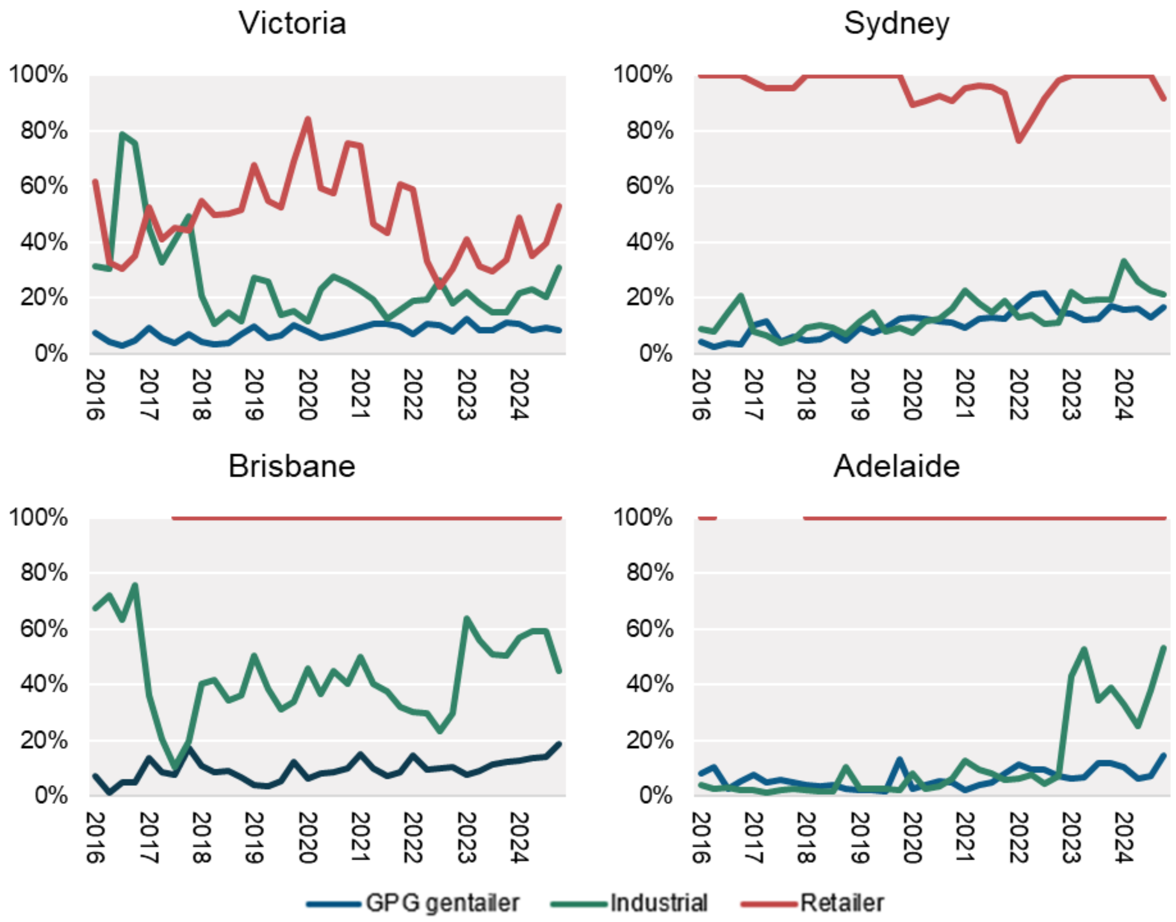
Most gas is traded on the east coast under long-term gas contracts that allow participants to hedge their position and reduce exposure to price volatility. However, securing a bilateral agreement at a reasonable price and good conditions may be challenging, particularly for smaller participants that are less connected to the gas markets and looking to trade smaller volumes of gas. High levels of spot price exposure may be cause of concern if participants do not have adequate options to hedge their positions in the market.

For this report we have not directly assessed exposure to spot market prices because a participant may be using contracting outside of the spot markets to hedge against the price risk. For instance as noted in Chapter 3, participations may be using financial products such as ASX futures or OTC products. The usage of financial products and how they operate alongside other mechanisms to hedge spot prices is something the AER will be able to consider in greater detail with the financial information it intends to collect as part of its new wholesale gas market monitoring powers.

Nonetheless, we can assess the proportion of gas that a participant sourced directly from the spot market by looking at the proportion of their demand above their own scheduled supply, i.e. the proportion of net demand to total demand. This can provide an indication of which participants may be taking on greater spot price risk and may need to use other options to hedge against this. This is particularly important to consider for participant groups with downstream retail or scheduled electricity generation demand, and therefore with less flexibility to be opportunistic in their level of buying in the spot markets.

Our analysis shows that among groups with large downstream demand – GPG gentailers, industrials and retailers – there are varying levels of net buying across the downstream spot markets. Despite this, smaller retailers and industrials appear to engage in the highest proportion of net buying (Figure 20).

**Figure 20 Quarterly proportion of net demand to total demand by participant group, 1 January 2016 to 31 December 2024**




Source: AER analysis of DWGM and STTM data.

Key findings for each participant group include:

- **GPG gentailers tend to have the lowest proportion of net buying, with typically 70–80% of their demand hedged with their own supply, and this is consistent across most participants.** We understand this is due to GPG gentailers with known and large retail and generation demand that requires access to large long-term GSAs to provide long-term supply security.
- **The level of net buying among industrials varies considerably in each downstream spot market.** In the Victoria and Sydney STTMs, industrials have had around 80% of their demand hedged with their own supply. In Adelaide, net buying is considerably higher, reaching around 50–60% in recent years. In Brisbane there has historically been very low proportions of net buying, driven largely by the closure of Incitec Pivot's Gibson Island Fertiliser Facility in Queensland.[34] This large reduction in total demand left a group of smaller industrials with low total demand and relatively higher levels of net buying.

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[34] Australian Manufacturing, Incitec Pivot to close its Gibson Island manufacturing operations, accessed 9 May 2025.

- **Retailers are almost 100% net buying in the STTMs.** While this suggests some retailers may be highly exposed to spot prices, they may also have contractual arrangements to hedge these risks. The slight reduction in net buying in Sydney was driven by the exit of Weston Energy. In Victoria, retailers have significantly lower proportions of net buying, particularly in the past 2 years.

  There is also a strong seasonal component in Victoria, with retailers increasing their proportion of net buying during summer months and decreasing during winter months. This suggests retailers in Victoria may be contracting at higher levels than in the STTMs and can adjust their position to expected seasonal variation in spot prices. It may also reflect retailers using spot markets to refill storage capacity during summer months.

## 6.3 Spot markets appear to be supporting efficient arbitrage opportunities

The downstream spot markets provide participants the opportunity to arbitrage across major demand centres on the east coast and move gas to where it is valued most in response to short-term market dynamics.

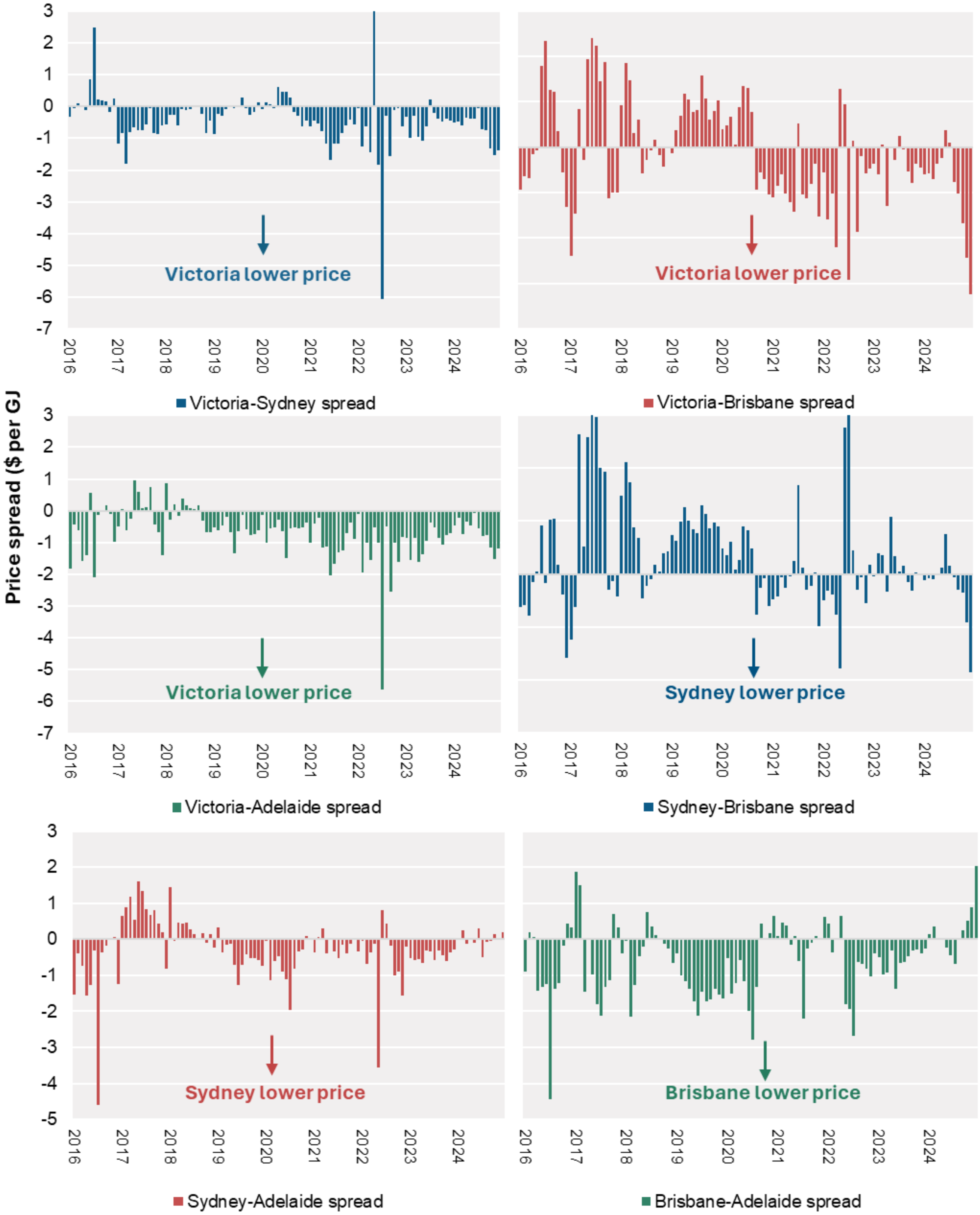
Traders have become increasingly active on the downstream spot markets since 2019, likely in part due to opportunities to move gas between markets to arbitrage prices. The increase in trader activity also coincides with the introduction of the DAA, which has provided traders with access to cheap, short-term transport capacity and facilitates arbitrage.

However, the downstream spot markets appear to be supporting arbitrage and other profitable opportunities for a wider range of participants. For instance, during consultation a few exporters and producers and GPG gentailers noted their involvement in arbitrage and that decisions to buy and/or sell gas can be made in response to favourable prices. As noted in chapter 4, exporters and producers and GPG gentailers typically operate in multiple if not all 4 markets and so would be well-positioned to take advantage of arbitrage opportunities as they emerge, especially if they already have contracted pipeline capacity available.

To measure the opportunity for arbitrage between the downstream spot markets, we considered the average price difference between each pair of spot markets since 2016 (Figure 21). Overall, this shows that the price spread in downstream spot markets is often less than $1 between markets, suggesting significant arbitrage likely already occurs and little additional opportunity exists given the costs of transport would likely be higher than this. For instance, long-term firm transportation on key north–south pipelines is typically priced between $1 and $2 per GJ per day and short-term transport would typically include a premium on top of this.[35] However, arbitrage may still be possible where participants use DAA capacity that typically clears at $0. In consultation, several participants noted using the DAA in conjunction with spot markets to find arbitrage opportunities.

35 AER, Wholesale gas market focus report - Day Ahead Auction, Australian Energy Regulator, October 2024.

**Figure 21 Average monthly price spreads between downstream spot markets, 1 January 2016 to 31 December 2024**




Note: The price spread measures the difference between daily spot prices of spot market hub pairs and averaged for the month.
Source: AER analysis of DWGM and STTM data.

Between individual markets there is greater variation in the spread of prices. While price differences across the spot markets sometimes follow a seasonal pattern, they largely appear to fluctuate more rapidly or follow a longer-term trend:

- Since 2021 Victoria has largely had lower prices on average than the other downstream spot markets, which may reflect the overall size of the market, and higher levels of liquidity putting downward pressure on prices. Given the DWGM market price does not incorporate VTS charges, this may also influence the lower prices relative to the STTMs. Occasionally the price difference can be closer to $2, suggesting opportunities likely regularly exist to arbitrage cheaper gas available in Victoria.
- Prior to 2021 Brisbane tended to have lower prices than the other downstream spot markets, particularly during 2019 and 2020. This may be due to Brisbane being relatively close in proximity to large gas fields at Roma, Queensland, and benefiting from lower prices during this time due to the LNG netback price falling below domestic prices.[36]
- Adelaide has largely had higher prices than all other markets since 2016. While this suggests opportunities to arbitrage with the Adelaide market exist, these price differences are relatively consistent and significant. This suggests there may be structural issues blocking cheaper gas from flowing into Adelaide. This may be due to the smaller size and liquidity in the market, which would reduce the arbitrage opportunity as well as transportation barriers. Some participants in consultation noted that transportation access to the Adelaide hub was more variable, which could impact available arbitrage opportunities. Notably, trader activity in Adelaide has been low compared with the other hubs, with only one of the 5 traders participating there in recent years.

## 6.4 DAA supports trading opportunities on the downstream spot markets but could be better aligned

During consultation, several participants noted that DAA transportation complemented their trading activity in the downstream spot markets.

However, one issue that may be limiting the DAA's ability to support downstream spot market activity is a misalignment between the STTM and DAA schedules. As STTM bids and offers must be submitted before DAA capacity is made available, market participants must schedule into the STTM without knowing whether DAA capacity will be available to support those commitments. If capacity turns out to not be available, the participant would either need to use contracted pipeline capacity, which would generally be more expensive and potentially render the intended trade uneconomical or incur deviation charges on the STTM.

Multiple participants noted in consultation that misalignment between the STTM and DAA schedules was a notable frustration or risk, with one even reporting that it had been a factor in their decision not to use the DAA. However, some participants reported that they were comfortable accepting this risk of occasionally having to pay more than planned for transportation. It was suggested guidelines on how to use the DAA in conjunction with

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36 AER, Wholesale markets quarterly – Q3 2020, Australian Energy Regulator, November 2020.

STTMs would be helpful to let market participants, including pipeline operators, better understand and manage the risks involved.

Some participants also raised concerns about transportation constraints becoming more severe in the future. Stakeholder feedback in the AER's inaugural Pipeline monitoring and transparency report[37] found that contracts were also becoming less flexible over time, hampering participants' abilities to respond to price signals and arbitrage opportunities in the spot markets.

## 6.5 Gas spot markets and electricity generation

The rapid responsiveness of gas-powered generators makes them suitable for meeting peak electricity demand and offsetting variability in wind and solar generation. While in recent years there has been an overall decline in GPG demand across states, GPG demand is projected to grow in the coming years and increase more rapidly in the coming decades unless new renewable sources of firming capacity can be found to replace it.[38]

Most participants' gas demand for GPG will be sourced under GSAs. However, participants may also use spot markets and storage facilities to manage short-term variations in demand for GPG or high electricity prices.

In consultation, several GPG gentailers suggested that the flexibility of intra-day trading on the DWGM was beneficial to managing GPG demand variation in comparison to the day-ahead design of the STTMs. However, this difference in design was also understandable given the greater responsive of demand to weather variability in Victoria that needed to be managed. One participant also noted that market carriage on the DWGM was allowing them to adapt better to intra-day changes to demand as transportation contracts needed for contract carriage to the STTMs tend to be more rigid.

One GPG gentailer provided some suggestions for potential improvement to the design of the spot markets to better support gas-powered generation:

- better aligning the day-ahead STTM schedule with the NEM pre-dispatch time – currently, the STTM schedule is ahead of the NEM pre-dispatch and alignment would allow fuel to be purchased after electricity needs are known so participants can better respond to high demand periods
- moving to a price-based withdrawal system rather than a price taker withdrawal system on the DWGM for large loads – the current system creates uncertainty around price that can at times disincentivise buying gas for generation.

Each of these suggestions would require considerable reform to the current systems, and consideration of the trade-offs, benefits and costs of the change would be needed. For instance, moving to a price taker withdrawal system would require consideration of the greater burden put on GPG gentailers to manage compliance with deviations, which could also lead to issues with system security.

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37 AER, Pipeline monitoring and transparency report, Australian Energy Regulator, 2025.

38 AER, State of the Energy Market 2024, Australian Energy Regulator, November 2024, p. 163.

Given the significant and complex interconnections between GSAs, transportation, storage and the facilitated markets, the AER will investigate these suggestions and further analyse gas and electricity connections as part of its Wholesale gas competition report in 2026.