AUSTRALIAN COMPETITION & CONSUMER COMMISSION

Gas inquiry 2017–2025

Interim report

July 2022

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Australian Competition and Consumer Commission
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Acronyms

ACQ	Annual contract quantity
ADQ	Average daily quantity
C&I	commercial and industrial
CPI	Consumer Price Index
CSG	coal seam gas
CTP	capacity trading platform
DAA	day-ahead auction
DQT	downward quantity tolerance
DWGM	Declared Wholesale Gas Market
EOI	Expression of interest
FID	financial investment decision
FSRU	floating storage and regasification unit
GPG	gas powered generation/generator
GSA	gas supply agreement
GSOO	Gas Statement of Opportunities
GTA	gas transportation agreement
JKM	Japan Korea Marker
LNG	liquefied natural gas
MDQ	maximum daily quantity
NGL	National Gas Law
NGR	National Gas Rules
RIS	Regulation Impact Statement
SPAs	sale and purchase agreements
STTM	Short-term trading market
WAP	weighted average price

Organisation	
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIE	Australian Industrial Energy
APPEA	Australian Petroleum Production and Exploration Association
COAG	Council of Australian Governments (cessation in May 2020)
GBJV	Gippsland Basin Joint Venture
ICE	Intercontinental Exchange
RBA	Reserve Bank of Australia
Pipelines	
AGP	Amadeus Gas Pipeline
CGP	Carpentaria Gas Pipeline
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
PCA	Port Campbell to Adelaide Pipeline
QGP	Queensland Gas Pipeline
RBP	Roma to Brisbane Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
VTS	Victorian Transmission System
LNG plant	
GLNG	Gladstone LNG
APLNG	Asia Pacific LNG
QGC	Queensland Curtis LNG

Units	
MMBtu	Million British Thermal Units–see Glossary, Units of Energy
GJ	Gigajoule
PJ	Petajoule
TJ	Terajoule

Overview

This is the July 2022 interim report of the Australian Competition and Consumer Commission's (ACCC's) inquiry into gas supply in Australia (the Inquiry).

This report sets out our usual reporting on the supply outlook, the domestic price outlook, commercial & industrial (C&I) user experience, transportation and storage, as well as Stage 2 of our in depth examination of upstream competition and the timeliness of supply.

This report also addresses the Treasurer's request in his letter of 6 June 2022, in which he asked us to ensure the factors influencing prices in gas markets (domestic and export) are made fully transparent and to bring to the Government's attention any need for regulatory change to ensure electricity and gas markets function properly for the benefit of all Australians.

Australia is a country with relatively abundant gas resources. Gas produced in the east coast is supplied to both domestic users in the east coast gas market - C&I users, gas powered generators (who also retail gas), and retail and small business customers - and overseas buyers in Asia through sales of LNG.

Much of the gas produced in the east coast is produced by the LNG exporters. On an aggregate basis, the LNG exporters and their associates had influence over close to 90% of the 2P reserves in the east coast in 2021, through a combination of their direct interests in 2P reserves, joint venture and exclusivity arrangements. This may increase the risk of coordinated conduct and increase the market power of the LNG exporters.

As part of our regular 6 monthly reporting in the Gas Inquiry 2017-2025, we report on the expected supply-demand balance for the following year, using the Australian Energy Market Operator's (AEMO's) demand estimates from its Gas Statement of Opportunities, issued in March each year.

For our supply side reporting, we use compulsory information gathering powers under Part VIIA of the *Competition and Consumer Act 2010* (CCA) to collect information from domestic gas producers, LNG exporters and gas retailers/generators.

We collected information from these market participants up to mid-February 2022 on their forecast gas production and sales and price offers for 2023. Gas production and sales volumes estimates were also confirmed and updated with gas producers and retailers in May 2022.

We spoke to C&I users between March and June 2022 about their experiences seeking gas supply for 2023, as well as current pricing in the domestic spot markets in May/June 2022. C&I users have expressed great concern about the impact of recent price rises, if they continue. Some users noted closure of operations was becoming a very real possibility in the short term and more significant demand destruction was likely over the longer term. In June 2022, Advance Bricks announced it was closing its manufacturing operations employing over 20 people due to gas price rises and Australian Textile company Flickers is also reported to be facing closure.[1]

[1] Gillian Aeria, Rising gas prices blamed as Advance Bricks says its oven will go cold after 82 years in Stawell, ABC Wimmera, 17 June 2022, https://www.abc.net.au/news/2022-06-17/gas-prices-advance-bricks-energy-crisis-regional-jobs/101161446; Whitson, Rhiana, Australia's gas crisis is worse than you might think. Industries warn thousands could lose their jobs and consumers will pay more, ABC News, 3 June 2022, https://www.abc.net.au/news/2022-06-03/gas-crisis-threatens-manufacturers-jobs-and-rising-prices/101114712

As shown in chart O.2 below, the east coast of Australia is forecast to produce 1981 PJ of natural gas in 2023. Much of this gas will be exported to overseas markets in Asia under long term contracts. In 2023, 1299 PJ of gas is forecast to be exported under long term contracts with overseas buyers (Sale and Purchase Agreements, SPAs). The remaining 'excess' gas[2] LNG exporters in Queensland expect to produce, above their contractually committed volumes, can be supplied either to the domestic market or to overseas markets. Since 2018, we have observed that LNG exporters have exported at least half - and more frequently, around 70% - of their excess gas to overseas spot markets.

The domestic east coast gas market uses a relatively small proportion of the total east coast gas production each year. For 2023, AEMO forecasts that domestic east coast gas demand will be around 571 PJ, requiring approximately 29% of all the gas expected to be produced for the year.

However, if all the excess gas of LNG exporters is sold in overseas markets then the domestic east coast gas market is likely to be 56 PJ short of gas needed to meet forecast demand for 2023. This is a worse situation than that which occurred in 2017, when both the ACCC and AEMO predicted a shortfall of gas for the following year, and which led to the Australian Government at that time:

- commencing the Australian Domestic Gas Security Mechanism (ADGSM) process for determining whether 2018 would be a shortfall year
- ultimately entering into a Heads of Agreement (HoA) with LNG exporters, under which LNG exporters agreed to make excess gas available to the domestic market prior to exporting it.

The ADGSM is an export control mechanism, which allows the Minister for Resources to determine if the following calendar year is likely to be a shortfall year in the domestic market and, if it is, apply export controls on the LNG exporters to limit the amount of gas they can export as LNG.

The HoA has been replaced twice since 2017. A well-functioning HoA should ensure that LNG exporters make gas broadly and transparently available to all domestic C&I users (and gas retailers) at demonstrably competitive prices, in volumes and for periods suitable to buyers' needs, and with sufficient notice.

In its current form, LNG exporters have committed to offer uncontracted gas to the domestic market on ‘competitive market terms’ and ‘with reasonable notice’ before offering it to the international market, and to have regard to prices they could reasonably expect to receive for uncontracted gas in overseas markets and domestic spot markets.

Since 2017 and following the signing of the first HoA, there has largely been sufficient gas forecast to be supplied into the east coast gas market to avoid a shortfall. However, our estimates have forecast an increasingly tight supply outlook and we have observed that LNG exporters have:

- exported the majority of their excess gas into LNG spot markets overseas
- forecast to withdraw increasing amounts of gas out of the domestic market since 2021 (having previously supplied more gas into the market than they withdrew through gas supply contracts with domestic producers).

[2] Consistent with the approach taken in earlier reports, we refer to the gas that LNG exporters expect to have in excess of their contractual commitments under both domestic contracts and the long term SPAs as 'excess gas'. It is referred to as 'excess gas' because it is not contractually committed and could therefore be supplied into either the domestic market or the international LNG market. It is, however, worth noting that LNG exporters have informed us that they expect to export the vast majority of this gas as spot cargoes or additional LNG sales.

In the current environment of high international energy prices (including gas and LNG), tight LNG markets, broader supply chain problems, geopolitical instability, inflation and uncertain demand for GPG domestically, we support the Australian Government placing greater focus on energy security.

Both the HoA and the ADGSM are due to expire on 1 January 2023.

Given this, the current domestic and international energy environment and the forecast supply outlook we support the recent announcement by the Minister for Resources that the Australian Government will renegotiate the HoA and renew the ADGSM beyond 1 January 2023. We consider that the ongoing operation of these arrangements will be needed to ensure sufficient gas is supplied into the domestic market to meet demand.

We also recommend that the Australian Government strengthen both arrangements and welcome the Minister for Resources' announcement that the Australian Government will also review the ADGSM. Additionally, The ACCC welcomes the Minister's recent announcement to extend the ADGSM to 2030.[3]

A summary of some of the key limitations in the current ADGSM are set out in box O.1 below.

Box O.1: Summary of ADGSM limitations

There are a number of potential shortcomings in the ADGSM which should be considered as part of the Australian Government's announced review.

Flexibility in initiating or applying the ADGSM

Currently, the Minister for Resources can only initiate the ADGSM in the year before a domestic shortfall year.

The Guidelines and DISER indicate the timing of the Minister's notification will occur ideally by 1 July but no later than 1 October. This means the entire duration of the ADGSM process could take between three and six months before any export controls would take effect.

The Total Market Service Obligation calculation

The Total Market Security Obligation (TMSO) is the proportion of a domestic supply shortfall that the Minister considers should be met by imposing export controls on LNG projects that are in net-deficit.

In its 2020 review of the ADGSM, DISER found that the TMSO may not be able to recover sufficient domestic gas to address a potential market shortfall. This is due to the 'net-deficit' component only enabling export restrictions on volumes of gas where exporters are drawing more gas from the domestic market than they are putting in.

Treatment of gas as third party export compatible gas

Prior to determining the TMSO, the Minister determines each LNG Project's net market position and whether each LNG Project is likely to be in net-deficit or a net-contributor to the domestic market in the forthcoming calendar year.

An LNG Project will be regarded as being in net-deficit in the forthcoming calendar year if its Total gas used is greater than the sum of its Own gas and Third party export compatible gas.

The current application of the ADGSM could see export controls only applying to one LNG Project, and this may be to the LNG project with the least amount of excess gas (requiring them to breach their contractual obligations).

As already noted, supply conditions in the east coast market are expected to deteriorate significantly in 2023, with a shortfall of 56 PJ now expected. This is equivalent to around 10% of domestic demand and is the largest projected supply shortfall we have forecast since the Inquiry commenced in 2017. LNG exporters are expected to contribute to the shortfall in 2023 by withdrawing 58 PJ more gas from the domestic market than they expect to supply

3 https://www.minister.industry.gov.au/ministers/king/media-releases/extending-adgsm-2030-secure-domestic-gas-supply

into the market.[4] They also expect to export the vast majority of their 167 PJ of 'excess gas'. In total, the LNG exporters expect to export 1,441 PJ of gas in 2023, which is significantly more than what they have exported in previous years.

Our supply outlook also shows it is highly likely that a significant proportion of the LNG exporters' excess gas will be needed in the domestic market to avoid a shortfall. As an immediate measure, we therefore recommend that the Minister initiate the first step of the ADGSM process, to:

- formally determine whether 2023 will be a shortfall year
- work with LNG exporters to supply more gas into the domestic market in 2023 over the latter half of 2022, so that the domestic market doesn't commence the 2023 supply year facing a material shortfall in supply.

We also strongly encourage LNG exporters to act immediately to increase their supply into the east coast gas market.

There is a significant risk to the east coast's energy security in 2023 with a projected shortfall in supply of 56 PJ

The east coast gas market is facing a 56 PJ shortfall in supply in 2023, signifying a substantial risk to Australia's energy security. This shortfall is a significant deterioration in conditions relative to the 2022 forecast and suggests a bleaker outlook for 2023 than AEMO projected in its latest Gas Statement of Opportunities (GSOO). This could place further upward pressure on prices and result in some manufacturers closing their businesses, and some market exit has already occurred.

The supply shortfall in 2023 is 54PJ higher than the shortfall projected at the same time last year for 2022. This is primarily due to a 52 PJ increase in forecast demand by GPG and a 24 PJ increase in LNG exporters' export forecasts, which are offset partially by a 23 PJ reduction in forecast demand by residential and C&I users (predominantly relating to C&I users). The effects of these changes are concentrated in the southern states (NSW, Victoria, South Australia, Tasmania and the Australian Capital Territory) where gas resources have been diminishing for some time and where the majority of C&I users are located, with a 54 PJ shortfall is forecast.

In Queensland, where the LNG exporters and their production and export facilities are located, and where the majority of future reserves and resources are, a 2 PJ shortfall is expected.

The LNG exporters are expected to contribute to the supply shortfall in 2023 by withdrawing 58 PJ more gas from the domestic market than they expect to supply into it. As shown in chart O.1, domestic third party purchases (from other gas producers who supply into the domestic market) will increase to 214 PJ while sales to the domestic market are expected to fall to half the volume actually supplied in 2017.[5]

Between 12 August 2021 and 16 February 2022 LNG exporters sold 22 additional or spot cargoes for a total of 81 PJ. In this time, they contracted to supply the domestic market

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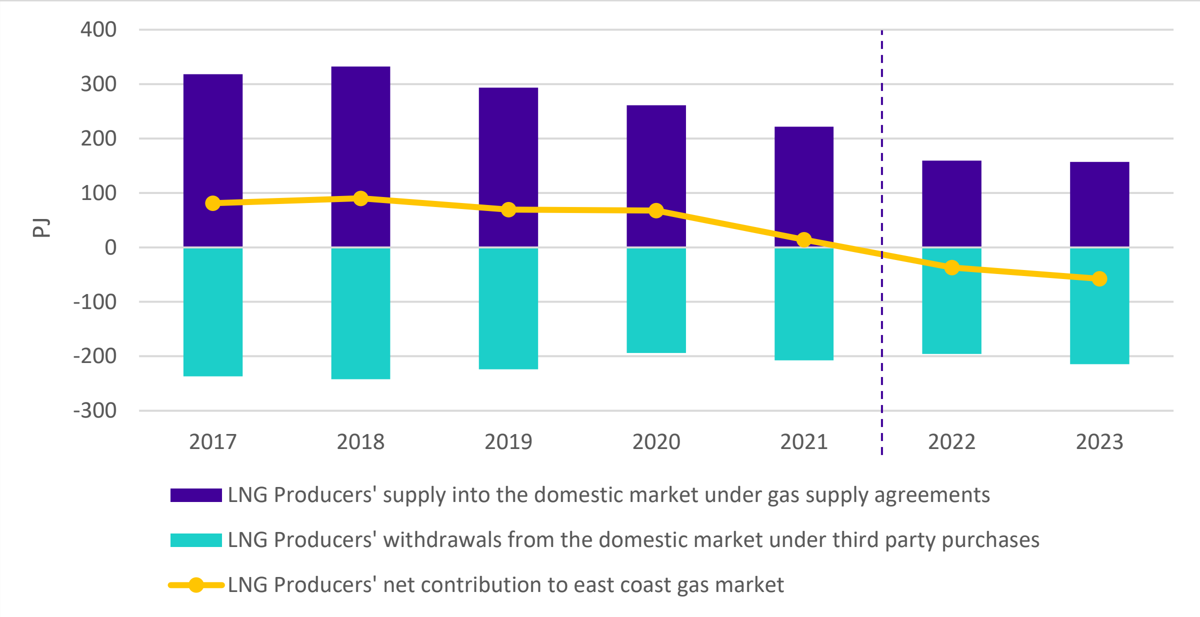
4 We emphasise that our net contribution calculation is based solely on the LNG exporters' supply into the domestic market under GSAs, and withdrawals from the domestic market under purchases from third parties. Our approach does not consider whether these purchases from third parties are 'third party export compatible gas' as defined in the ADGSM and as the question of determining if gas in 'third party export compatible gas' is a matter for the Minister for Resources under the ADGSM Guidelines, the ACCC has not collected information from parties that would help determine this question.

5 The purchase and supply of gas by LNG exporters from and into the domestic market respectively can be attributed to LNG producers balancing the time and location at which they supply or source gas to meet their supply obligations. As noted in footnote 2, we do not estimate net contributions based on the operation of the ADGSM.

23.5 PJ on a short term basis, however 8 PJ of this was contracted to other LNG exporters. Over this period, LNG exporters did not contract any gas for domestic supply with a term length of 1 year or greater.

Chart O.1: LNG exporters' net contributions to the east coast gas market



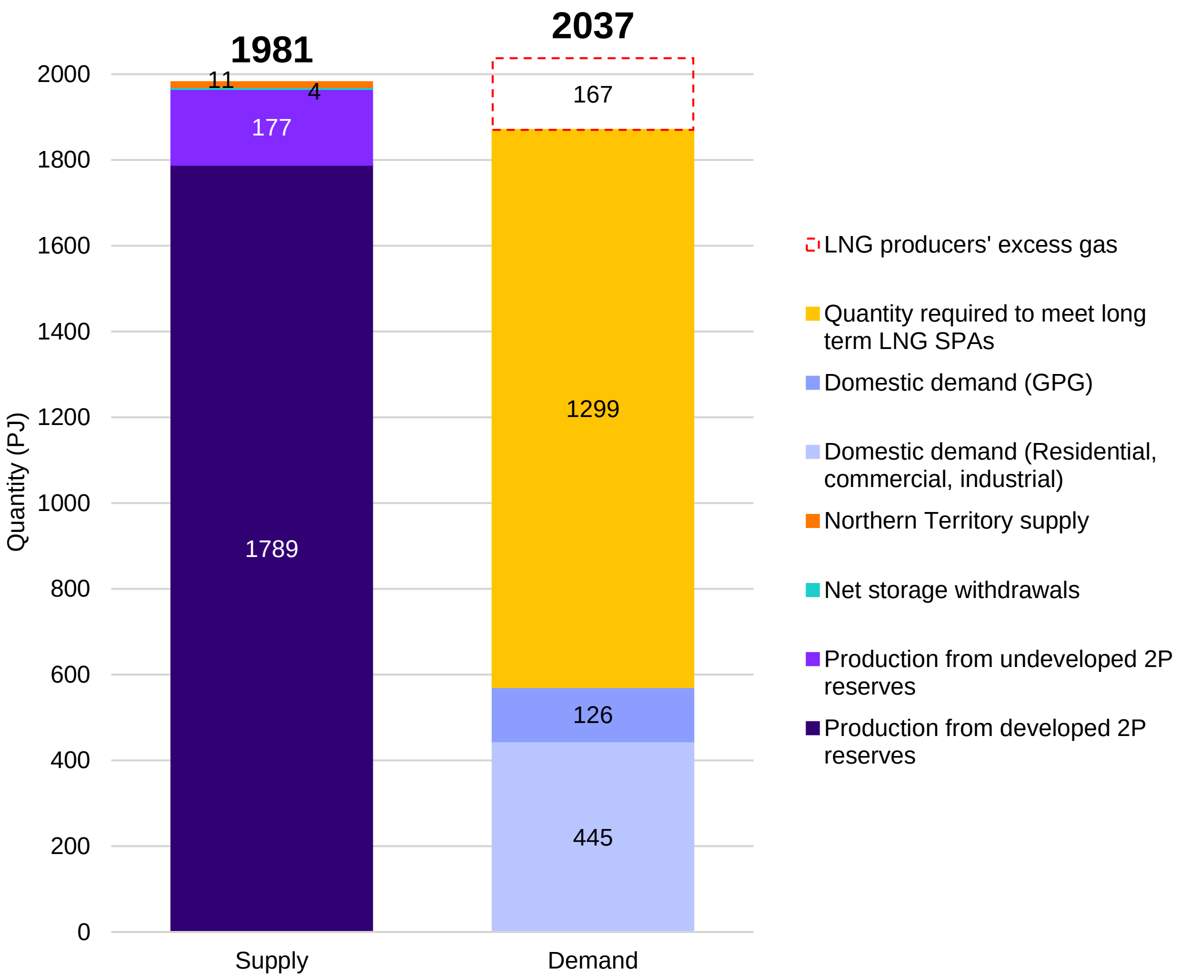
The forecast 56 PJ shortfall shown in chart O.2 below is likely to result if LNG exporters decide to export all the gas that they expect to have in excess of their contractual commitments (167 PJ) as they did in 2021. This would be a 65% increase in forecast spot sales relative to 2022.

To address the projected shortfall in 2023 significant additional volumes of gas will need to be:

- produced in the east coast from gas fields that are already connected to the market
- produced in the Northern Territory and transported via the Northern Gas Pipeline (NGP) into the east coast
- withdrawn from storage and/or
- diverted by LNG exporters into the domestic market.

However, these possible means of addressing the shortfalls are in large part dependent on the decisions of the LNG exporters and all but the last measure are likely to have only a small impact on the forecast shortfall.

Chart O.2: Forecast east coast supply-demand balance in 2023



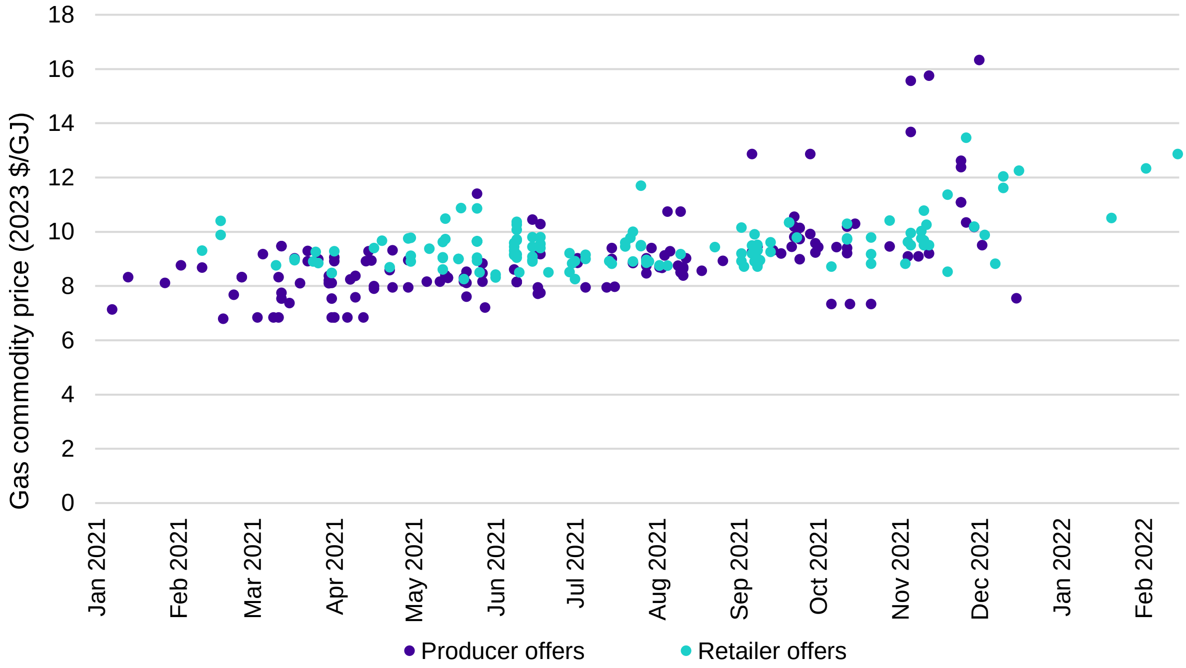
It is very likely that to avoid the forecast shortfall in the east coast gas market in 2023, LNG producers will need to divert a significant proportion of their excess gas into the domestic market. This has led us to recommend that the Minister for Resources initiate the first step of the ADGSM process, and also strongly encourage LNG exporters to act immediately to increase their supply into the east coast gas market.

Users are receiving offers at higher prices with less flexibility

Prices offered for supply in 2023 increased over the course of 2021, accelerating from around August 2021, as shown in chart O.3. Prices offered around $16/GJ, made between November and December 2021, are the highest we have observed since early 2017.

Weighted average prices offered by producers for 2023 supply have climbed above $10/GJ, and for the first time quantity weighted average producer prices have exceeded those offered by retailers.

Chart O.3: Gas commodity prices (2023$/GJ) offered in the east coast gas market for 2023 supply



Global gas and oil prices increased sharply in the second half of 2021 and prices offered by producers for supply in Queensland largely tracked this increase.

Prices offered to users in southern states also increased in the latter part of 2021 but were lower than Queensland prices.

The average price payable for 2023 supply in recent Gas Supply Agreements (GSAs) in the southern states is expected to be $9.25/GJ for supply by producers, and $10.01/GJ for supply by retailers. The average price under GSAs with producers in Queensland is expected to be $7.37/GJ.

Users reported LNG exporters were making price offers linked to the ACCC's export parity price series (the LNG netback price series) for the first time and expressed concern that this had only occurred once LNG netback prices were high. Many users were reluctant to sign up to these prices, due to the inherent uncertainty they saw in these price mechanisms.

We are very concerned at reports of even higher prices being offered to C&I users in April and May 2022, with reports of gas price offers as high as $21.20/GJ. We are also concerned with the extremely high prices observed in domestic spot markets since May 2022 (Section 2.2), along with high LNG prices, which may flow through to long term contract prices.

While in previous years some users engaged directly with domestic spot markets to help secure their gas needs and pay lower prices, they have been exposed to significantly higher prices since our last report. They are also now facing increasingly volatile domestic spot markets. Managing spot market trades and acquiring the necessary pipeline transportation services, as well as effectively hedging price risks, can be particularly difficult for smaller firms.

Similarly, spot market volatility can also impact customers of some retailers, as can be seen by the recent market suspension of Weston Energy by the Australian Energy Market Operator, which supplied gas obtained via spot markets.[6]

Concerns about supplier behaviour reported in the January 2022 interim report have intensified. Users report suppliers are unwilling to negotiate offers and are offering reduced flexibility in non-price terms.

A well-functioning HoA with LNG exporters could ensure that LNG exporters make gas broadly and transparently available to all domestic C&I users (and gas retailers) at demonstrably competitive prices, in volumes and for periods suitable to buyers' needs, and with sufficient notice.

While further improvements have been made by LNG exporters in demonstrating compliance with the HoA, we remain concerned that some LNG exporters are not engaging with the domestic market in the spirit in which the HoA was signed. Even if some behaviour might be argued to be technically compliant, there remain instances where some suppliers are not engaging with the domestic market in ways that are likely to result in supply agreements being reached and market conditions improving. In particular, we are concerned:

- with instances of LNG exporters not providing counteroffers to parties that bid into EOIs
- that reasonable notice does not appear to always be provided to domestic market participants
- that an LNG exporter is offering gas to the domestic market at prices it cannot reasonably expect to receive when selling uncontracted gas to the international market.

There remains significant scope for LNG exporters to learn from ACCC concerns about the behaviour of other LNG exporters, based on our examination of material provided to us to demonstrate HoA compliance. We will provide a summary of all our findings on compliance directly to each LNG exporter to provide further guidance and encourage improved HoA compliance.

Transport and storage costs will become increasingly relevant to many gas users

The forecast 54 PJ shortfall for southern states in 2023 means the net amount of gas transported south will likely need to increase over the course of the year. There is currently sufficient capacity on the relevant facilities to enable this.

Over the longer term, changes in the location of gas supply and demand centres will continue to affect the demand of gas transportation and storage services. The relative decline of production in the southern states will further increase the need to transport gas from Queensland and, to some extent, the Northern Territory to meet demand.

This growing dependence on the infrastructure of a small number of operators is concerning given the monopoly pricing previously observed by the ACCC largely persists. Since our last report, most transportation prices have moved in line with inflation, maintaining monopoly pricing.

Where gas must travel on multiple pipelines, the transportation costs can be significant. For example, the standing price for transporting gas from Wallumbilla to southern demand

6 AEMO suspended Weston Energy from trading in all hubs of the Short Term Trading Market and the Victorian Domestic Wholesale Gas Market with effect from 24 May 2022, due to Weston being unable to meet the liquidity requirements to trade in these markets.

centres can range from $2.24 to $2.58/GJ which is a significant proportion of commodity gas prices. The cost of transporting gas from the Northern Territory is significantly higher.

The regulatory reforms for gas pipeline regulation announced in April 2022 should improve transparency by pipeline operators and should strengthen the relative bargaining position of shippers.

The local monopolies enjoyed by pipeline operators are also a feature of gas storage infrastructure. Storages are also expected to play an increasingly important role in meeting peak demand periods throughout the year. The Dandenong LNG storage facility plays an important role in meeting intraday peak periods for retailers and other major users, as well as system security more generally. AEMO recently contracted 60TJ of LNG reserve (storage capacity) on 20 January 2022 to counteract the threat to system security in the Victorian Transmission System.

Ensuring sufficient supply in the east coast market is critically dependent on measures to improve competition and encourage timely supply

Recent events across the east coast's gas and electricity markets have shown the consequences of having insufficient gas supply to meet demand and ineffective upstream competition. Concerningly, supply conditions in the east coast gas market are expected to deteriorate further in 2023, with a significant supply shortfall now expected. This is expected to occur against the backdrop of a highly concentrated upstream market, with competition posing little constraint on the behaviour of producers.

In January 2021 we announced our intention to undertake a review of upstream competition and the timeliness with which gas is brought to market. This review is being undertaken in response to concerns raised throughout the Inquiry about the degree of concentration in this part of the market and the structural and behavioural factors that may be impeding competition or limiting gas supply. The need for the review has been reinforced by:

- the pricing behaviour we have observed over the course of the Inquiry and our review of suppliers' pricing strategies, which indicates that competition is posing little constraint on producers' pricing decisions[7]
- the C&I user surveys we have undertaken, which have consistently raised concerns about the lack of effective upstream competition and the adverse effect this has on selling practices, gas prices and non-price terms and conditions in GSAs.

Stage 1 was completed in January 2022 and focused on the structural factors that may be impeding competition or the timeliness of supply. We found that:

- Greater diversity and more timely supply could be encouraged through changes to government processes for releasing acreage and approving, monitoring and enforcing compliance with work programs.
- Upstream competition and the timeliness of supply could be significantly improved by reducing the infrastructure, regulatory and capital barriers faced by producers, including by introducing a light-handed third party access regime for upstream infrastructure.

Stage 2 has focused on the degree of concentration in the part of the market and the behavioural factors that may be impeding competition or the timeliness of supply. Our key findings of this stage of the review are that:

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[7] See ACCC, Gas inquiry 2017-2025 interim report, January 2021, p. 8 and ACCC, Gas inquiry 2017-2025 interim report, July 2021, p. 11.

- The upstream market is highly concentrated and dominated by the three LNG exporters and their associates. In 2021, the three LNG exporters and their associates had influence over close to 90% of the 2P reserves in the east coast, through a combination of their direct interests in 2P reserves, associates, JVs and exclusivity arrangements. This highlights the effective control that the LNG exporters have over the supply and development of gas in the east coast, as well as competition in the domestic market.
- JVs can adversely affect competition if participants do not put in place and adhere to robust ring-fencing arrangements that prevent the sharing of commercially sensitive information,[8] with other projects in which JV participants have an interest. A JV participant can also have the incentive and opportunity to exploit their position in a JV to delay the development of gas if it improves the participant's competitive position in other projects.
- Joint marketing by incorporated and unincorporated JVs is more prevalent than we expected, with the LNG exporters and some other producers engaging in joint marketing in the domestic market without authorisation. This results in a material reduction in the number of producers competing to supply gas into the domestic market.[9]
- Exclusivity provisions in GSAs entered into between domestic producers (as sellers) and LNG exporters (as buyers) are restricting the ability of domestic producers to compete to supply gas into the domestic market. These provisions can also reduce the incentive that domestic producers have to develop gas over time and result in development decisions being based on the requirements of the LNG exporters, rather than the domestic market.
- Mergers and acquisitions of other producers, tenements or interests in JVs by larger producers, can result in a reduction in producers competing to supply gas into the market and slow the progress of gas development.

Together with the high degree of concentration in this part of the market, these arrangements contribute to a lack of effective upstream competition in the east coast. They may also increase the risk of coordinated conduct and increase the market power of the LNG exporters. This is concerning, given the supply conditions that are expected to prevail in the east coast in 2023 and beyond, and the reliance that will be placed on the LNG exporters to supply more gas into the domestic market.

Entering into these types of arrangements without authorisation risks breaking the restrictive trade practices provisions in Part IV of the CCA if they amount to cartel conduct, or have the purpose, effect or likely effect of substantially lessening competition.

While in the past producers may have considered that these arrangements would not substantially lessen competition, in a concentrated and tight market the effect on competition can be heightened. We will continue to review some of these arrangements and, where appropriate, consider enforcement action.

Producers should also consider whether they could implement changes to their arrangements to help improve competition and the timely supply of gas to the market as a matter of priority.

Future work of the inquiry

We expect to provide our next interim report in January 2023. Consistent with the 2017 direction from the then Treasurer to conduct a wide-ranging inquiry to improve transparency

8 For example, the JV's pricing and supply decisions.

9 In this report, the term 'joint marketing' is used to refer to arrangements that limit individual participants in a JV (incorporated or unincorporated) from separately and independently marketing gas for supply into the domestic market. See chapter 5 for more information.

and monitor gas supply, and the most recent letter from the current Treasurer to monitor and report on prices and the supply of gas, we will provide updates on:

- the prices offered and agreed for gas supply for 2023
- the gas supply outlook for 2023 and the longer term outlook to 2034
- the C&I gas user experience
- the pricing and utilisation of transportation and storage services.

We will continue publishing the LNG netback price series, and make information available and policy recommendations where we consider it appropriate and necessary.

Our priorities over the next 12 months will be to:

- continue our review of upstream competition, in particular how producers make decisions about when to bring gas to market and any potential competition concerns under the CCA
- assist the Australian Government as appropriate as it reviews the ADGSM and renegotiates the HoA
- assist in the ADGSM process to determine if 2023 is likely to be a shortfall year, should the government commence that process
- monitor and report on compliance with the HoA signed with LNG exporters
- monitor and report on the implementation of the Gas Code of Conduct
- commence our examination of competition in the supply of gas to C&I users.

1. Supply and demand outlook

Key points

- The east coast gas market is facing a 56 PJ shortfall in supply during 2023[10] and is a significant risk to energy security. This shortfall is equivalent to around 10% of expected domestic demand in 2023.
    - This is a substantial deterioration in conditions relative to the 2022 forecast[11] and suggests a bleaker outlook for the market in 2023 than AEMO projected in its March 2022 Gas Statement of Opportunities (GSOO).
    - The projected shortfall for 2023 could place further upward pressure on prices and result in some C&I customers shutting down.
- The projected shortfall in 2023 is 54 PJ higher than the shortfall projected at the same time last year for 2022. This deterioration can largely be attributed to an increase in forecast demand, with:
    - AEMO projecting a 52 PJ increase in GPG demand
    - LNG exporters expecting to export 24 PJ more gas in 2023
    - a 23 PJ reduction in residential and C&I demand only partially offsetting these increases.
- At a regional level, the southern states (NSW, Victoria, SA, ACT and Tasmania) are expected to experience a 54 PJ shortfall in 2023, due to declining production in the south and a projected increase in demand from gas powered generators. In Queensland there is expected to be a shortfall of 2PJ.
- Additional supply from the Northern Territory and non-LNG controlled storage could help to alleviate some, but not all, of the projected shortfall in the east coast. It is highly likely that LNG exporters would need to divert more gas into the domestic market to avoid a shortfall in 2023. However, in 2023 LNG exporters have forecast to:
    - withdraw 58 PJ more gas from the domestic market than they expect to supply into it, and
    - export the vast majority of the gas they have in excess of their contractual commitments (167 PJ) as spot cargoes or additional LNG sales.
- The effective operation of both the Heads of Agreement (HoA) and Australian Domestic Security Mechanism (ADGSM) will be required to ensure LNG exporters supply more gas into the domestic market and maintain Australia's energy security.
- The ACCC:
    - recommends that the Australian Government initiate the ADGSM process for establishing whether 2023 will be a shortfall year and work with LNG exporters to supply more gas into the domestic market in 2023 over the latter half of 2022, so that the domestic market doesn’t commence the 2023 supply year facing a material shortfall in supply
    - supports the Minister for Resources' announcement that the Australian Government renegotiate the HoA and renew the ADGSM, both of which are due to expire on 1 January 2023, to ensure energy security in the east coast gas market in 2023 and beyond
    - welcomes the Minister for Resources' announced review of the ADGSM and recommends that the Australian Government strengthen both the ADGSM and HoA.
- Recent announcements by market participants and the Australian Government of additional gas production, infrastructure developments and investments suggest additional gas could be supplied into the market in the medium to longer-term. However, this will not occur in time to alleviate the shortfall in 2023.

[10] All demand estimates within this chapter are based on the 'Progressive Change scenario' in AEMO's 2022 GSOO.

[11] All comparisons to 2022 in this chapter are based on forecasts that appeared in our July 2021 interim report.

1.1. Introduction

This chapter provides an overview of the short term supply and demand outlook for the east coast gas market as a whole and for two regions: Queensland and the southern states. It also sets out the results of our analysis of the forecasts for demand and supply made in 2020 for 2021 compared with what actually occurred in that year and outlines a number of recent market developments that could affect supply in the medium to longer term.

The short term outlook focuses on the 2023 supply year and compares:

- total forecast demand, which includes domestic demand (i.e. residential, commercial & industrial (C&I) and GPG demand) and the quantities of gas required by the LNG exporters[12] to meet their long term LNG SPA commitments[13] and expected spot cargoes, with
- total forecast supply, which includes production from 2P developed and undeveloped reserves, net storage withdrawals, and expected gas flows from the Northern Territory into Queensland.

The domestic demand forecast used in this chapter is based on AEMO's March 2022 GSOO Progressive Change scenario (see Box 1.1 for more detail).[14] Supply and LNG demand data was obtained directly from producers in response to compulsory information notices issued in February 2022:

- Producers provided forecast production quantities from developed and undeveloped 2P reserves, possible reserves, contingent and prospective resources and forecast flows from the Northern Territory into Queensland.
- Cooper Basin producers provided forecasts of how much of their gas is expected to flow into Queensland and the southern states.
- The LNG exporters provided forecasts of LNG demand under their long term Sale and Purchase Agreements (SPAs) and under LNG spot cargoes or additional LNG sales.

In May 2022 we contacted LNG exporters, domestic producers and retailers to confirm this supply and LNG demand data and made some revisions to reflect the updated forecasts.

Consistent with the approach taken in earlier reports, we refer to the gas that LNG exporters expect to have in excess of their contractual commitments under both domestic contracts and the long term SPAs as 'excess gas'. It is referred to as 'excess gas' because it is not contractually committed and could therefore be supplied into either the domestic market or the international LNG market. It is, however, worth noting that LNG exporters have informed us that they expect to export the vast majority of this gas as spot cargoes or additional LNG sales.

12 The three LNG exporters are APLNG, GLNG and QCLNG.

13 Quantities required to meet long-term LNG export contracts are based on LNG exporters' expectations as at May 2022. The quantity actually supplied under these contracts in 2023 may vary due to, for example, flexibility provisions in contracts, the execution of additional contracts or unexpected LNG plant maintenance.

14 AEMO, Gas Statement of Opportunities (GSOO) [online document], 2022.

Box 1.1: Demand scenarios in AEMO's 2022 GSOO

In prior GSOOs AEMO has presented a Central scenario, which we have used for domestic demand forecasts. In its most recent GSOO, AEMO has presented two potential Central scenarios: the Progressive Change and the Step Change scenarios. In 2023, there is only a 12 PJ difference between the domestic demand forecasts arising under these two scenarios. Domestic demand under the Progressive Change scenario is forecast to be 562 PJ, while under the Step Change scenario it is forecast to be 550 PJ.

Although the difference is relatively small in 2023, AEMO noted in the 2022 GSOO that "urgent action would be needed to put south-eastern regions on the Step Change path by next winter".[15] There are no signs as yet that this action is being taken. We have therefore decided to take a more conservative position by using the Progressive Change scenario for our 2023 domestic demand forecast. While we have decided to use the Progressive Change scenario for the short term outlook, we intend to have regard to both scenarios when we examine the longer-term outlook in our next interim report.

1.2. The east coast gas market is forecast to have a supply shortfall in 2023 and domestic energy security will be at risk

Chart 1.1 sets out the forecast supply-demand balance in the east coast for the 2023 supply year. It shows that domestic and LNG export demand in the east coast (2037 PJ) is projected to exceed supply (1981 PJ) in 2023, resulting in a **supply shortfall of 56 PJ**.

This is a significant deterioration in conditions relative to what we projected for 2022 at the same time last year and presents a real risk to Australia's energy security. It is also a bleaker outlook for 2023 than what AEMO presented in its latest GSOO (published in March 2022), with AEMO projecting that conditions would be tight on peak days (particularly in the south-east), but on an annual basis there should be sufficient gas to meet demand.[16]

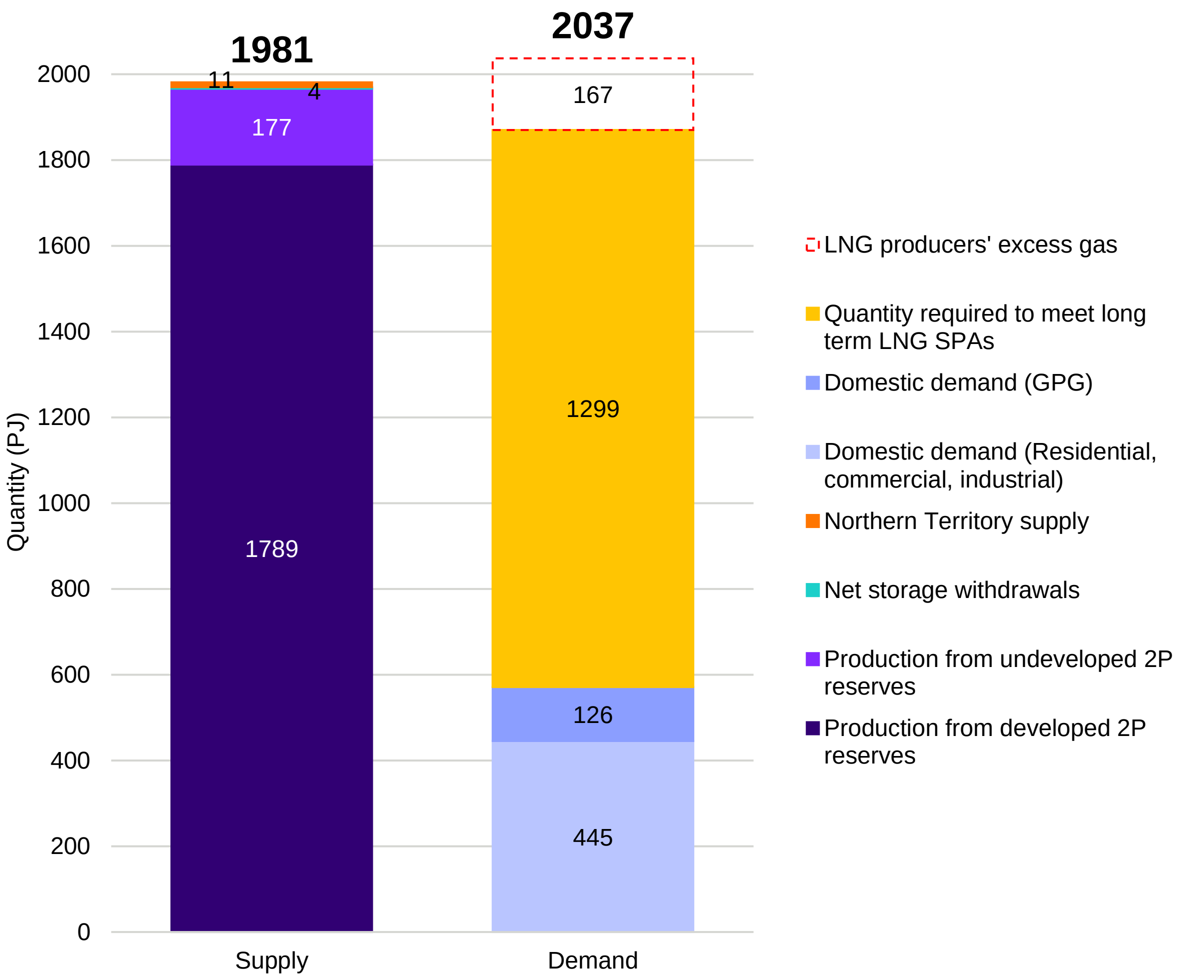
We have worked with AEMO to understand the source of the difference in our forecasts and it would appear that our production from 2P reserves forecasts are around 59 PJ lower than AEMO's. This difference primarily stems from discrepancies between the forecasts provided by producers in the Cooper and Otway basins to AEMO and those provided to us under compulsory information notices issued under the CCA. We have discussed this with the producers in question and expect that going forward they will provide AEMO with information that is consistent with what they provide the ACCC (subject to any differences arising as a result of time at which the ACCC and AEMO request information from the producers).

In any case, the outlook for 2023 is very concerning and is likely to place further upward pressure on prices, which could result in some C&I users no longer being able to operate. It could also lead to demand having to be curtailed. These effects are likely to be felt most acutely by gas users in the southern states, but given the interconnected nature of the market could also affect users in Queensland.

15 AEMO, Gas Statement of Opportunities (GSOO) [online document], 2022, p. 11

16 AEMO, Gas Statement of Opportunities (GSOO) [online document], 2022, p. 66.

Chart 1.1: Forecast east coast supply-demand balance in 2023



Source: ACCC analysis of data obtained from gas producers as at May 2022 and the domestic demand forecast (Progressive Change scenario) from AEMO's March 2022 GSOO.

Note: Totals may not add up due to rounding.

1.2.1. How do the 2023 forecasts differ from the 2022 forecasts?

The deterioration in the outlook for 2023 can largely be attributed to a 54 PJ increase in forecast demand, with the largest changes being made to:

- AEMO's GPG forecasts, which are 52 PJ higher in 2023 than what it forecast for 2022. This increase follows a detailed review by AEMO of the accuracy of its GPG forecasts, with AEMO noting in its latest GSOO that its forecasts have consistently under-estimated demand over the last five years (primarily as a result of generator outages and weather events).[17]
- LNG exporters' export forecasts, which are 24 PJ higher in 2023 than what was forecast for 2022 across LNG SPAs and expected spot cargoes.

These increases in demand have been partially offset by a 23 PJ reduction in AEMO's residential and C&I forecasts, with C&I users accounting for the majority of the projected fall.

[17] AEMO, Gas Statement of Opportunities (GSOO) [online document], 2022, p. 73.

In contrast to the increase in demand, supply is expected to be approximately the same as in 2022. While total supply is roughly the same overall, there has been an increase in supply from 2P reserves (11 PJ), which is expected to be offset by a reduction in storage withdrawals (8 PJ) and flows from the Northern Territory (4 PJ).

1.2.2. What impact are LNG exporters likely to have on the 2023 outlook?

The LNG exporters will significantly influence the 2023 supply-demand balance in the east coast, with LNG exports forecast to reach 1456 PJ in 2023. Table 1.1 shows the contribution of the LNG exporters to the supply-demand balance in 2023.

Table 1.1: LNG exporters 2023 forecast supply-demand balance (PJ)

	2023
Supply available to LNG exporters	
Production + storage withdrawals	1409
3rd party domestic purchases	214
Total supply LNG exporter	**1623**
Contracted and uncontracted demand for LNG exporters' gas	
Domestic GSAs (contracted)	157
Long term LNG SPAs (contracted)	1299
Excess gas (uncontracted)	167
Total demand	**1623**
ACCC's calculation of LNG exporters' net contribution to the east coast (Domestic GSAs - 3rd party domestic purchases)	
Domestic GSAs	157
3rd party domestic purchases	214
Net contribution	**-58**

Source: ACCC analysis of data obtained from LNG exporters as at May 2022 and the domestic demand forecast (Progressive Change scenario) from AEMO's March 2022 GSOO.

Note: Totals may not add up due to rounding. The quantity required to meet the contractual obligations under the long-SPAs includes the feed gas required to produce LNG (such as fuel). In 2023, this usage is expected to total 101 PJ.

While LNG exporters expect to have sufficient gas to meet their contractual obligations under domestic GSAs and long-term LNG SPAs in 2023 (1623 PJ versus 1456 PJ), they expect to export the vast majority of their uncontracted gas (167 PJ) as spot cargoes or additional LNG sales. This is consistent with what we observed for 2021, with 99% of the uncontracted gas that was forecast for 2021 (100 PJ) exported as spot cargoes and as additional sales under long term SPAs (see section 1.6).

The LNG exporters also expect in 2023 to:

- supply 2 PJ less gas into the domestic market than they did in 2022, with the overall volume of gas contracted to be supplied into the domestic market being less than half of what was supplied into the domestic market by LNG exporters in 2017 and 2018
- withdraw an additional 19 PJ from the domestic market through purchases from third parties.

In net terms, the LNG exporters expect to withdraw 58 PJ from the domestic market in 2023. This is a further deterioration in the LNG exporters' net contribution to the east coast market, as highlighted in Chart 1.2.

Of the three LNG exporters, QCLNG and GLNG are net withdrawers, while APLNG is a net contributor.

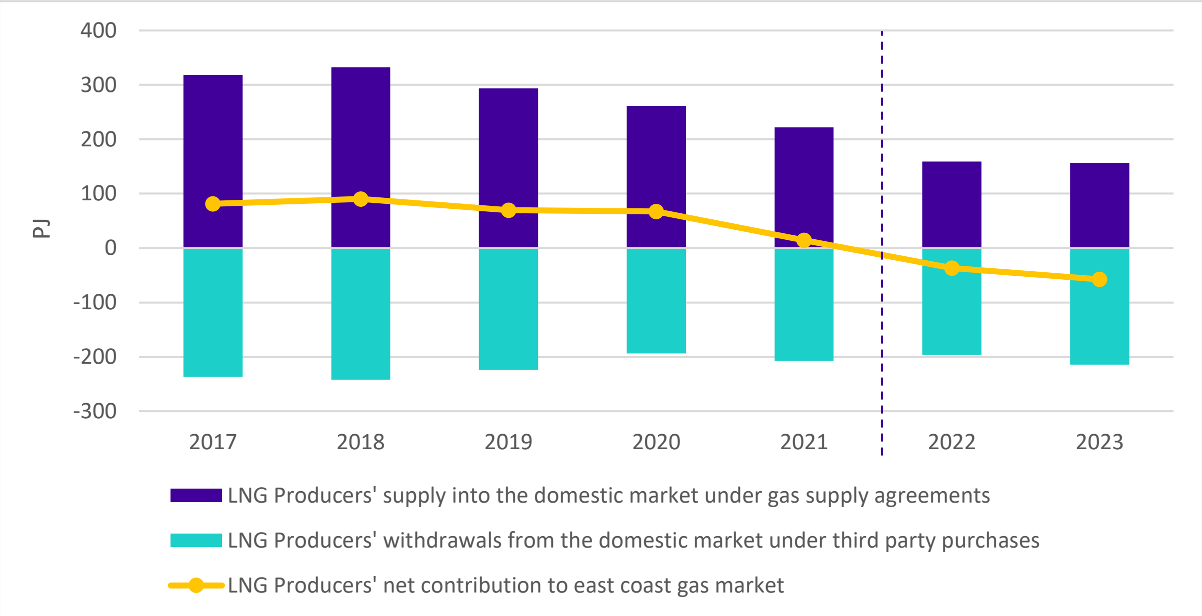
Consistent with our previous interim reports, we have taken the approach that any domestic gas produced by a third party and purchased by an LNG exporter is a withdrawal from the domestic market and provides an appropriate picture of the current state of the domestic east coast gas market.

Our approach to calculating the LNG exporters' net contribution to the domestic market differs from the ADGSM's net-deficit test. For example, LNG exporters have stated that some of the gas that we have included as withdrawals from the domestic market should be treated as 'third party export compatible gas' for the purposes of the ADGSM. Under the ADGSM, this would have the effect of reducing the extent an LNG exporter was in net-deficit.

We emphasise that our net contribution calculation is based solely on the LNG exporters' supply into the domestic market under GSAs, and withdrawals from the domestic market under purchases from third parties. Our approach does not consider whether these purchases from third parties are 'third party export compatible gas' as defined in the ADGSM and, as the question of determining if gas in 'third party export compatible gas' is a matter for the Minister for Resources under the ADGSM Guidelines, the ACCC has not collected information from parties that would help determine this question.

The treatment and definition of third party export compatible gas would be an appropriate matter to consider as part of the review of the ADGSM announced by Minister King.[18]

Chart 1.2: LNG exporters' net contributions to the east coast gas market



Source: ACCC analysis of data obtained from LNG exporters as at May 2022.

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18 Joint media conference with Minister for Climate Change and Energy Chris Bowen and Minister for Resources and Northern Australia, 9 June 2022

Box 1.2: Limitations of the ADGSM

The ADGSM was introduced in 2017 following a forecast gas supply shortfall in the eastern domestic gas market in AEMO's March 2017 GSOO. It is an export control mechanism, which allows the Minister for Resources to determine if the following calendar year is likely to be a shortfall year in the domestic market. If it is, the Minister can apply export controls on the LNG exporters to limit the amount of gas they can export as LNG.

There are a number of potential shortcomings in the ADGSM which should be considered as part of the Australian Government's announced review.

Flexibility in initiating or applying the ADGSM

Currently, the Minister for Resources can only initiate the ADGSM in the year before a domestic shortfall year. To initiate the first step of the ADGSM, the Minister must issue a notification of their intention to consider whether the forthcoming calendar year will be a domestic shortfall year.

The Guidelines and DISER indicate the timing of the Minister's notification will occur ideally by 1 July but no later than 1 October. This means the entire duration of the ADGSM process could take between three and six months before any export controls would take effect.

The Total Market Service Obligation calculation

The Total Market Security Obligation (TMSO) is the proportion of a domestic supply shortfall that the Minister considers should be met by imposing export controls on LNG projects that are in net-deficit.

In its 2020 review of the ADGSM, DISER found that the TMSO may not be able to recover sufficient domestic gas to address a potential market shortfall. This is due to the 'net-deficit' component only enabling export restrictions on volumes of gas where exporters are drawing more gas from the domestic market than they are putting in.

To address this, DISER recommended the Australian Government consider changing the TMSO in a way that enables the recovery of gas beyond that currently permitted under the 'net-deficit' test.

DISER's recommended change, described as a '50/50 hybrid', allocates:

- half of the identified shortfall volume to applicable LNG projects on a pro-rata basis against LNG production capacity
- the remaining half of the shortfall, split in a way that is inversely proportional to the domestic gas contributed by each project.

Treatment of gas as third party export compatible gas

Prior to determining the TMSO, the Minister determines each LNG Project's net market position and whether each LNG Project is likely to be in net-deficit or a net-contributor to the domestic market in the forthcoming calendar year.

The net market position is a measure of the extent to which an LNG Project is drawing from, or adding to, the quantity of gas to the domestic market over the forthcoming calendar year.

An LNG Project will be regarded as being in net-deficit in the forthcoming calendar year if its Total gas used is greater than the sum of its Own gas and Third party export compatible gas.

An LNG Project will be regarded as a net contributor if it is not in net-deficit.

The larger the quantity of gas that is considered to be either Own gas or Third party export compatible gas for an LNG Project, the smaller the net-deficit (if any) will be and the less gas (if an) that an LNG Project can be required to redirect into the domestic market.

The current application of the ADGSM could see export controls only applying to one LNG Project, and this may be to the LNG project with the least amount of excess gas (requiring them to breach their contractual obligations).

1.2.3. What are the downside risks to the 2023 supply-demand balance?

As noted in prior reports, GPG demand represents a key risk to the outlook as it is highly volatile and difficult to forecast. While AEMO has revised its GPG forecasts, GPG demand is inherently difficult to forecast because it is critically dependent on weather and conditions in the electricity market. There is therefore still a risk that GPG demand could be higher than forecast, which would exacerbate the shortfall.

Another risk on the demand side is that C&I demand will be higher than forecast. In the latest GSOO, AEMO has projected that C&I demand in the east coast will fall by around 12.5 PJ in 2023. If this reduction in demand does not eventuate, then the shortfall could be higher than forecast.

The other key risk on the supply side stems from the reliance on production from undeveloped 2P reserves. As we have noted in prior reports, supply from this source is considered less certain because additional investment is typically required to bring production online. While this remains a risk, it is worth noting that the risk has declined somewhat, with a smaller proportion of supply expected to come from undeveloped 2P reserves in 2023 than was expected in 2022 (9% in 2023 compared to 11% in 2022).

1.2.4. How could the supply shortfall be alleviated?

To address the projected shortfall in 2023 significant additional volumes of gas will need to be:

- produced in the east coast from gas fields that are already connected to the market
- produced in the Northern Territory and transported via the Northern Gas Pipeline (NGP) into the east coast
- withdrawn from storage, and/or
- diverted by LNG exporters into the domestic market.

Producers in the east coast have informed us that they expect to produce an additional 72 PJ from possible reserves and 12 PJ from contingent resources in 2023, the majority of which is expected to be produced by the LNG exporters. As we have noted in prior reports, supply from these sources is highly speculative, which is why these estimates have not been included in the outlook. If this production is realised, it is possible that it could address the projected shortfall. However, given the majority of this gas is held by LNG exporters, it is more likely that the additional volumes will be exported.

Another potential source of supply is the Northern Territory. Suppliers in the Northern Territory have informed us that they have currently only contracted to supply 11 PJ of gas in the east coast in 2023, which is lower than what has been supplied in prior years. It is possible that more than 11 PJ of Northern Territory-produced gas could flow into the east coast to help alleviate the projected shortfall.[19]

The maximum amount of additional gas that could potentially be supplied from this source will be constrained by the 38 PJ p.a. capacity of the Northern Gas Pipeline (NGP). This means an extra 27 PJ of gas could *theoretically* be supplied from the Northern Territory in 2023, but this is not enough on its own to address the projected shortfall. While the

[19] Central Petroleum has recently announced that it has entered into agreements providing for the supply of non-firm gas into the Brisbane, Sydney and Melbourne facilitated markets. We also understand from discussions with suppliers that further contracting for 2023 could occur in the second half of the year. It is possible therefore that additional gas from the Northern Territory could flow into the east coast to help alleviate the projected shortfall.

Central Petroleum ASX announcement and media release (May 2022) 'Gas Sales Commence into the East Coast Trading Markets' [online document], Central Petroleum.

theoretical maximum amount of gas that could be supplied into the east coast via the NGP is 38 PJ p.a. the maximum amount of gas that has actually been supplied from the Northern Territory into the east coast to date has only reached 34 PJ p.a.[20]

Gas currently held in storage is another potential source of supply that could help to alleviate some of the projected shortfall. As outlined in Box 1.3, there is expected to be around 50 PJ of gas in underground storage facilities in Queensland and the Cooper Basin at the end of 2022. This could potentially be supplied into the domestic market. However, over 45% of this gas is owned by GLNG and could be exported or it could be kept in storage to meet future contractual commitments with domestic or overseas customers.

While it is possible that supply could be supplemented from these other sources, there are limits on how much gas could be supplied from the Northern Territory, and most of the other gas is controlled by the LNG exporters.

Avoiding the shortfall forecast for 2023 is likely to require the LNG exporters to supply more gas into the domestic market. This could be done by diverting some of their uncontracted gas into the domestic market. As noted above, LNG exporters expect to have 167 PJ of gas in excess of their contractual obligations in 2023 and while they currently expect to export the vast majority of this gas as spot cargoes or additional LNG sales, they are not yet bound to. A reasonable portion of this gas could therefore be diverted into the domestic market to avoid the projected supply shortfall.

Both the ADGSM and the HoA can be used to address the shortfall and help ensure domestic energy security.

Under the ADGSM, it is up to the Minister for Resources to decide whether to commence the process in the ADGSM to determine if the following year will be a shortfall year that can lead to export controls ultimately being imposed. Our analysis shows that the east coast gas market is expected to face a shortfall in 2023, and the LNG exporters are collectively in a position to address this shortfall through redirecting a portion of it to the domestic market. Accordingly, the ACCC recommends that the Minister initiate the first step of the ADGSM process: to formally determine if 2023 will be a shortfall year and to work with LNG exporters on more gas being supplied into the domestic east coast gas market in 2023.[21]

A well targeted HoA could ensure that LNG exporters make gas broadly and transparently available to all domestic C&I users (and gas retailers) at demonstrably competitive prices, in volumes and for periods suitable to buyers' needs, and with sufficient notice. Under the current HoA, LNG exporters have agreed that they will not offer uncontracted gas to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the domestic market.

Like the ADGSM, a new HoA could help to encourage the LNG exporters to divert some of the 167 PJ of uncontracted gas that they have indicated they will export into the domestic market. However, the current HoA is due to expire on 1 January 2023 and we have observed a number of deficiencies in how the HoA is working in practice and compliance with the reporting obligations (see Section 2.3).

The ACCC therefore supports the Australian Government renegotiating the HoA and recommends that the government strengthen the terms of the new HoA, particularly the compliance reporting obligations. The Australian Government should also explore any available early commitments with LNG exporters to supply forecast gas production to the domestic market well ahead of the gas being produced.

20 ACCC, Gas inquiry 2017-2025 interim report, July 2020, p. 38.

21 See subsection 7 (2) of the Customs (Prohibited Exports) (Operation of the Australian Domestic Gas Security Mechanism) Guidelines 2020 (the Guidelines).

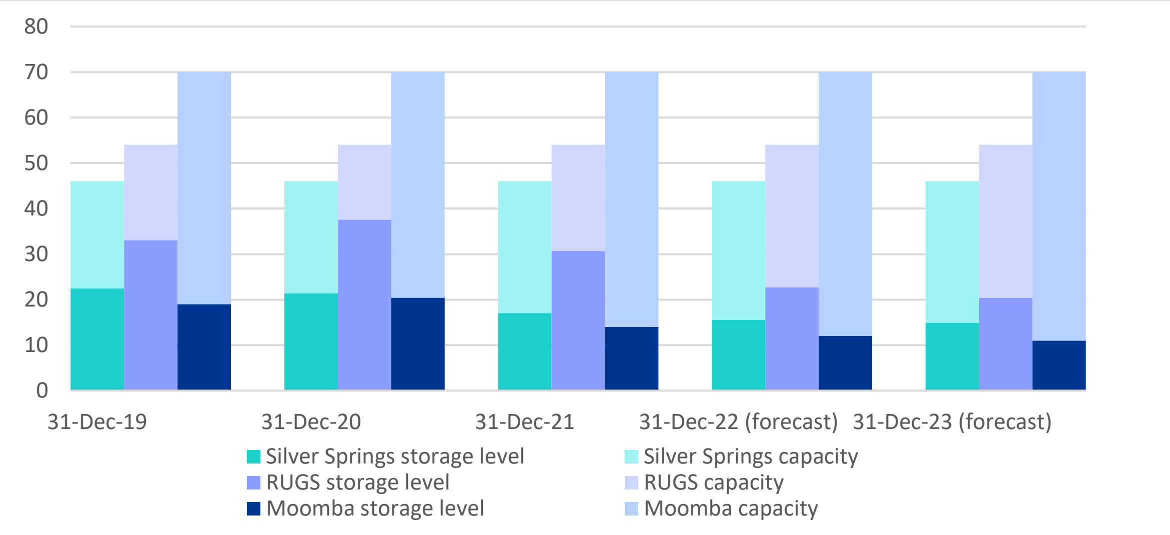
The ADGSM is also due to expire on 1 January 2023. Given that conditions in the east coast market are expected to continue to deteriorate over the medium to longer term and that domestic energy security will continue to be a risk, the ACCC supports the Minister for Resources' announcement that the ADGSM will be extended and reviewed. The ACCC also recommends that the Australian Government strengthen this mechanism. In this regard, we note that the Department of Industry, Science, Energy and Resources provided advice to the (then) Australian Government in 2020 to make changes to how the ADGSM operates and how export controls would be applied to LNG exporters.

Box 1.3: Storage levels in Queensland and South Australia

Chart 1.3 sets out actual storage levels between 2019 and 2021 and forecast storage levels for these facilities for 2022 and 2023 in:

- GLNG's Roma underground storage facility (RUGS)
- AGL's Silver Springs storage facility
- the Cooper Basin JV's Moomba storage facility.

Chart 1.3: Storage levels in Queensland and South Australia



Source: ACCC analysis of data obtained from gas producers as at May 2022.

Note: The above chart does not include figures for the Iona, Dandenong, or Newcastle gas storage facilities.

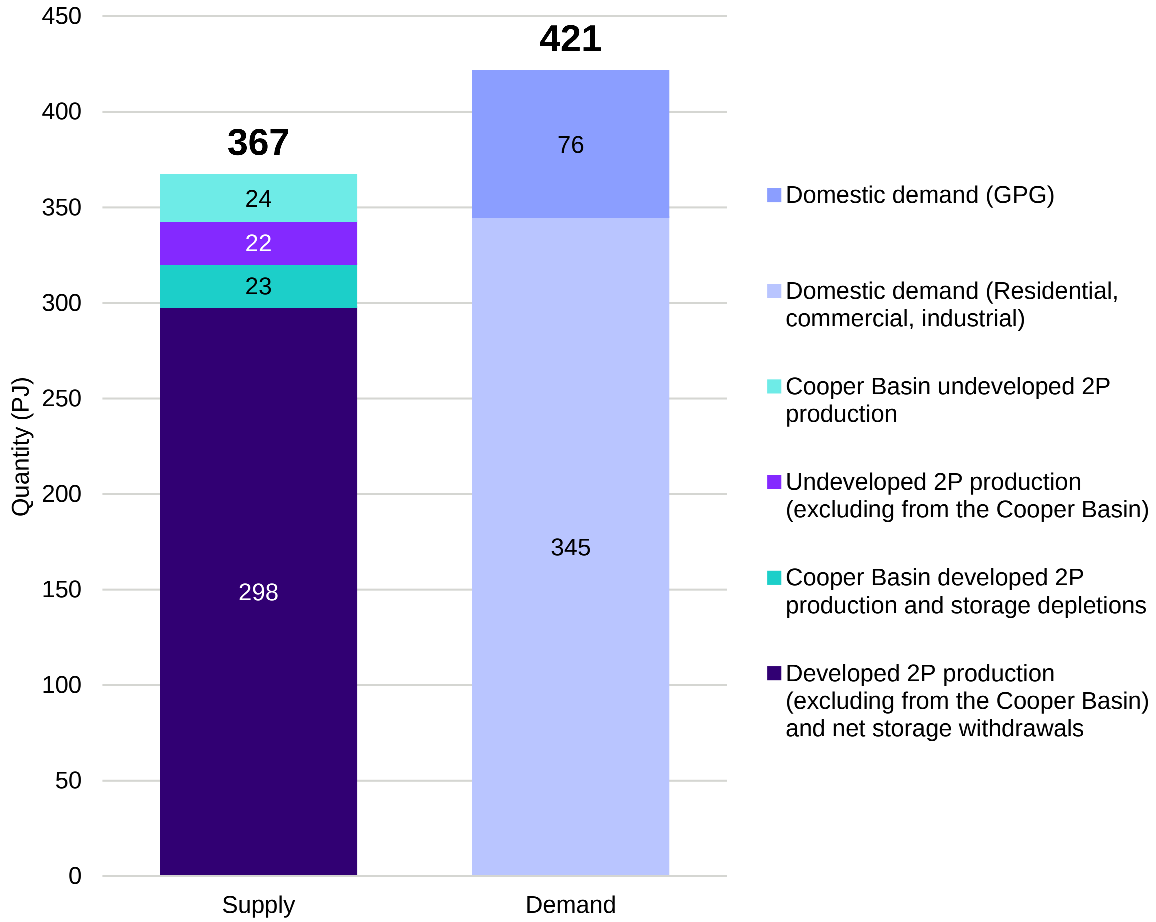
The chart shows that by the end of 2022 there is expected to be around 50 PJ of gas in these storage facilities, which could potentially be used to help alleviate the projected shortfall. It also shows that GLNG accounts for the majority of this gas, with the Roma storage facility expected to have around 23 PJ of gas in storage at the end of 2022.

Separately, but relatedly, AGL is evaluating the role of the Newcastle LNG storage facility in NSW in its portfolio and is not expecting to store any volumes there in 2023.

1.3. Substantial volumes of gas will be required to avoid a shortfall in the southern states in 2023

Chart 1.4 sets out the forecast supply-demand balance in the southern states for 2023. It shows that demand in the southern states (421 PJ) is forecast to exceed supply (367 PJ) by 54 PJ in 2023. This represents a further (almost tenfold) deterioration in conditions relative to what was forecast for 2022 at an equivalent time last year, when a shortfall of 6 PJ was forecast.

Chart 1.4: Forecast supply-demand balance in the southern states in 2023



Source: ACCC analysis of data obtained from gas producers as at May 2022 and the domestic demand forecast (progressive scenario) from AEMO's March 2022 GSOO.

Note: Totals may not add up due to rounding.

The deterioration in the supply-demand outlook stems from both an increase in demand and a reduction in supply, with:

- demand forecast to be 32 PJ higher than was forecast for 2022, primarily as a result of an increase in AEMO's GPG demand forecast, which is 35 PJ higher than its forecast for 2022, while its forecast for other sources of domestic demand is 3 PJ lower
- supply forecast to be 16 PJ lower than was forecast for 2022, primarily as a result of a 41 PJ reduction in forecast supply from 2P undeveloped reserves in the southern states. This is expected to be offset to some extent by a 19 PJ increase in supply from 2P developed reserves and a 5 PJ increase in forecast supply from the Cooper Basin.

Like the outlook for the east coast market as a whole, the key risks to the supply-demand balance in the southern states in 2023 are that:

- GPG will be higher than forecast
- supply from undeveloped 2P reserves, which is forecast to account for 7% of production in the south (excluding flows from the Cooper Basin), will be lower than forecast.

While the risk associated with GPG is expected to be lower following the revisions that have been made to AEMO's forecasts, it still represents a key risk, because the demand for gas by GPGs is critically dependent on weather and conditions in the electricity market.

In our January 2022 report, we noted that AIE had indicated that supply from the Port Kembla LNG import terminal could potentially commence in mid-2023 and that GB Energy had indicated that supply from the Golden Beach project could also commence in 2023. AIE has since advised that the Port Kembla project could now potentially commence from late 2023. GB Energy has also advised that supply from the Golden Beach project is unlikely to commence until 2024. Other sources of supply will therefore be required to address the supply shortfall in the southern states in 2023.

One other potential source of supply that has not been included in Chart 1.4 is production from possible reserves and contingent resources. Producers in the southern states have informed us that they expect to produce 1 PJ of gas from possible reserves in 2023, while Cooper Basin producers expect to produce less than 1 PJ of gas from possible reserves and 9 PJ from contingent resources. As outlined above, there is a significant degree of uncertainty surrounding this source of supply. However, even if it was to be produced and supplied in the south, the volumes are too small to avoid a shortfall. Gas will need to be transported from the north to the southern states to alleviate the projected shortfall. The expansion of both the South West Queensland Pipeline and the Moomba to Sydney Pipeline should help facilitate this.[22]

While there is likely to be sufficient pipeline capacity to bring gas south, AEMO has found that pipeline and storage capacity in the southern states are likely to be insufficient on peak winter days in 2023. Specifically, AEMO has found that under one-in-20 year demand conditions, small, infrequent supply shortfalls could occur in 2023.[23] To mitigate these shortfalls, AEMO noted that on-schedule completion of committed pipeline upgrades, greater operational management of LNG storage, and demand-side solutions are likely to be required.[24] We agree with these observations and note that without these measures in place, conditions could be even worse than projected in the southern states in 2023. Further information on gas transport and Victorian gas storage facilities can be found in Chapter 4.

1.4. Conditions will be tight in Queensland in 2023

Chart 1.5 sets out the expected supply-demand balance in Queensland (including supply from the Northern Territory) for 2023. Conditions are forecast to be very tight, and there will be a small shortfall of 2 PJ in 2023 if LNG exporters decide to export all of their excess gas. This is a minor deterioration from what was forecast for 2022 at the same time last year, when a 3 PJ supply surplus was projected.

The deterioration in conditions is largely due to the 21 PJ increase in forecast demand, which is expected to be countered somewhat by a 16 PJ increase in supply. The increase in demand is primarily a result of a 17 PJ increase in AEMO's GPG forecasts and a 24 PJ increase in the amount of gas that LNG exporters expect to export under LNG SPAs and spot cargoes. The increase in demand from these two sources is expected to be partially offset by a 20 PJ contraction in residential and C&I demand, with AEMO projecting that C&I customers in Queensland will account for around 75% of this contraction. While not stated in the GSOO, the reduction appears to be related to the closure of Incitec Pivot's Gibson Island plant at the end of 2022, which was announced in November 2021.[25]

22 AEMO, Gas Statement of Opportunities, March 2022, p. 58.

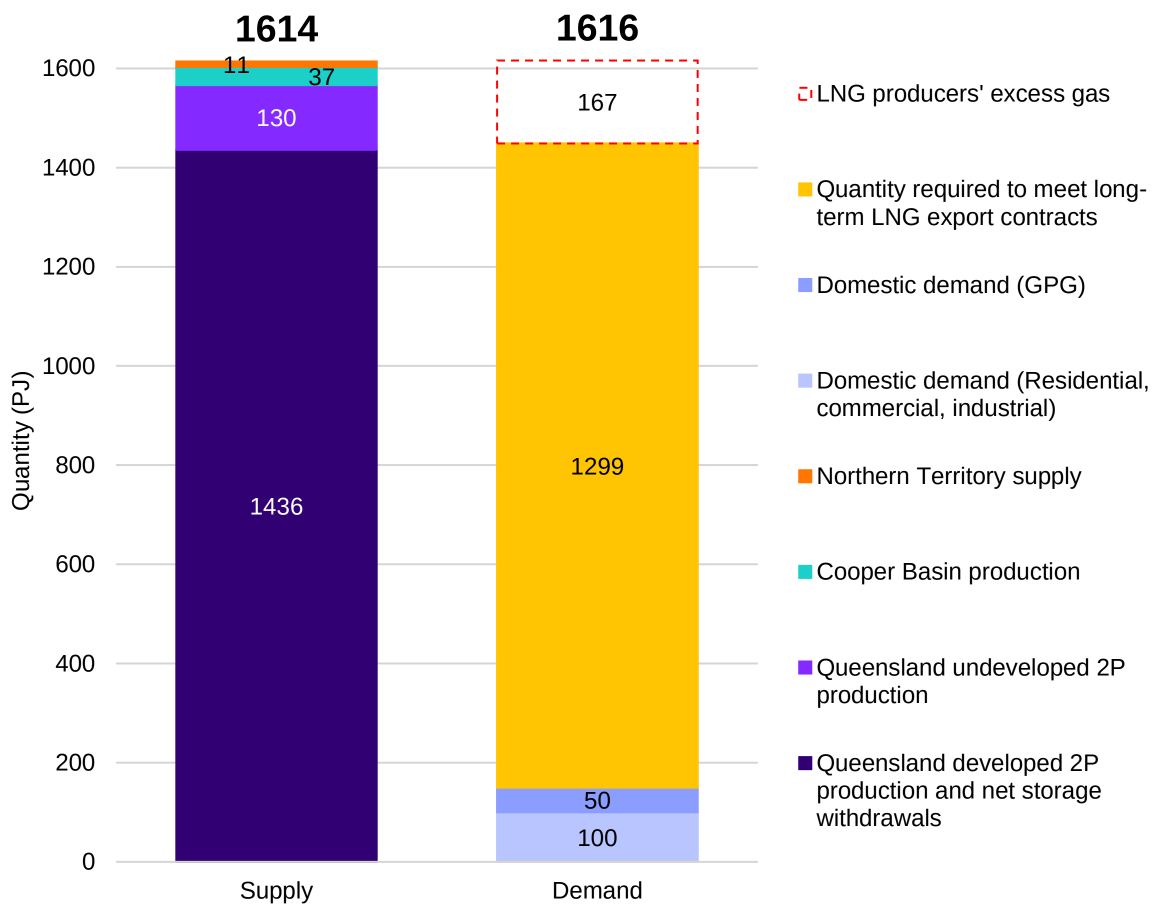
23 ibid, pp. 9-11.

24 ibid, pp. 62-63.

25 Incitec Pivot website (2021), 'Gibson Island manufacturing operations to cease at end of 2022', Incitec Pivot, 8 November 2021, accessed 4 May 2022.

On the supply side, production from 2P developed reserves is expected to be 33 PJ higher in 2023 than what was forecast for 2022, while supply from other sources is expected be 23 PJ lower. Production from 2P undeveloped reserves, for example, is expected to be 9 PJ lower, while net storage withdrawals are expected to be 6 PJ lower and flows from the Northern Territory are expected to be 4 PJ lower. Information provided by the Cooper Basin producers also indicates that flows from this basin into Queensland will be 4 PJ lower in 2023.

Chart 1.5: Forecast supply-demand balance in Queensland in 2023



Source: ACCC analysis of data obtained from gas producers as at May 2022 and the domestic demand forecast (Progressive Change scenario) from AEMO's March 2022 GSOO.

Note: Totals may not add up due to rounding.

Like the east coast forecast, the key risks to the supply-demand balance in Queensland in 2023 are that:

- GPG demand and/or C&I demand will be higher than forecast
- supply from 2P undeveloped reserves, which are subject to a greater degree of uncertainty than supply from 2P developed reserves, will be lower than forecast.

While not included in Chart 1.5, Queensland producers have informed us that they expect to produce an additional 70 PJ of gas from possible reserves and 3 PJ of gas from contingent resources in 2023, most of which is expected to be produced by the LNG exporters. Cooper Basin producers also expect to produce less than 1 PJ of gas from possible reserves and 9 PJ from contingent resources in 2023. As outlined above, these sources of supply have not been included in the outlook because there is a significant degree of uncertainty surrounding the development of these sources of supply. If this supply is realised, it could result in additional gas being supplied into the market, but as already noted it is also equally possible that this gas would be exported given it is largely controlled by the LNG exporters.

1.5. 2021 actual production and demand compared to forecasts

Table 1.2 compares the supply and demand forecasts made in 2020 for 2021[26] with what actually occurred in 2021.[27,28] It shows that in 2021 supply was 28 PJ (~2%) lower than forecast, while demand was 27 PJ (1%) higher than forecast. While by their very nature forecasts can be different from what is ultimately realised, the differences outlined in Table 1.2 underscore the key risks to the 2023 supply-demand outlook when there is little buffer between the supply forecast and demand forecast.

Table 1.2: Differences between forecast and actual supply and demand, 2021

Component	Forecast (PJ)	Actual (PJ)	Difference (Actual - Forecast)	
			PJ	%
Supply				
Queensland	1543	1526	-17	-1%
Cooper Basin	81	95	14	18%
Southern states	374	343	-30	-8%
Net storage withdrawals	13	18	5	38%
NT supply	19	18	-1	-5%
Total supply	**2029**	**2001**	**-28**	**-1%**
Demand				
Residential	194	196	2	1%
C&I	259	259	0	0%
GPG	71	98	27	38%
Long-term LNG SPAs	1304	1328	24	2%
LNG exporters' excess gas and LNG spot sales	100	75	-25	-25%
Total demand	**1929**	**1956**	**27**	**1%**

Source: ACCC analysis of information provided by suppliers; AEMO.

Note: This chart does not include forecast losses (or unaccounted for gas). For 2021, AEMO forecast that losses would total 17PJ in the east coast. AEMO does not provide figures for actual losses. Totals may not add up due to rounding.

The majority of the difference on the supply side occurred in the southern states, with actual production being 28 PJ lower than forecast. This can largely be attributed to the technical issues experienced at the Orbost processing plant, which resulted in supply from the Sole field being much lower than forecast. In the north, actual production in Queensland and

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26 The 2021 forecasts are based on the forecasts that appeared in our July 2020 interim report, which were revised in response to updated information. The revisions were set out in our January 2021 interim report. See https://www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2025/gas-inquiry-january-2020-interim-report and https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202021%20interim%20report_3.pdf.

27 Consistent with the approach taken in earlier reports, the analysis in this table is based on supply information (including information on production, net storage withdrawals and flows from the Northern Territory) provided by producers. Domestic demand information (including information on residential, C&I and GPG demand) is based on information from AEMO, while export demand information is based on information from the LNG exporters.

28 A comparative analysis of actual supply and demand from 2017 to 2020 can be found in our July 2021 interim report.

actual flows of gas from the Northern Territory were also lower than forecast, but this was offset by higher production from the Cooper Basin and greater withdrawals from storage.

On the demand side, most of the difference can be attributed to GPG, which was 27 PJ higher than forecast. In its most recent GSOO, AEMO noted that this was caused in part by the Callide Power Station outage in Queensland and the Yallourn coal mine floods in Victoria,[29] both of which impacted coal generation availability and led to increased GPG demand. In contrast, residential, C&I and total LNG export demand (across LNG SPAS and spot sales) were broadly in line with forecasts.[30]

The other interesting point to note from Table 1.2 is that 99% of the LNG exporters' uncontracted gas (100 PJ) was exported through a combination of spot cargoes (75 PJ) and higher than forecast supply under the long-term LNG SPAs (24 PJ).

1.6. Recent market developments suggest more gas could be brought to market in the medium to longer term

While the supply-demand outlook for 2023 has deteriorated, there have been some positive developments over the last six months that could result in more gas being supplied to the domestic market and greater security of supply over the medium to long-term. These include:

- the announced expansion of the Kipper and Turrum fields in the Gippsland Basin[31]
- the accelerated development of GB Energy's Golden Beach storage project
- the decision by APA to expand the South West Pipeline in Victoria[32]
- further progress on the development of Venice Energy's and AIE's proposed LNG import terminals.[33]

The Australian Government also announced funding for a number of natural gas, carbon capture and storage, and hydrogen projects in the 2022-23 budget.

Further detail on these developments is provided below.

1.6.1. Gippsland Basin expansion

Esso announced in March 2022 that it will spend $400 million to expand production from the Kipper field and move forward with its plans to enlarge the Turrum field.[34] Esso has stated that the expansion could add as much as 200 PJ of gas between 2023 and 2027 if both fields are developed and deliver the expected volumes of gas. While development of the Kipper field has been approved and is expected to supply around 30 PJ by 2023, a final decision on the development of the Turrum field is not expected to be made until mid-2022.[35] This increased production has been incorporated into our forecast for 2023.

29 AEMO, Gas Statement of Opportunities, March 2022, pp. 73-74.

30 ACCC (2020) Gas Inquiry 2017-2025 Interim Report: July 2020, section 1.2, pp. 18-21; ACCC (2021) Gas Inquiry 2017-2025 Interim Report: July 2021, section 1.6, pp 24-26.

31 Australian Financial Review (2022), 'Esso plans $400m gas production expansion' [online document], Australian Financial Review.

32 The Australian Pipeliner (2022), '$60 million expansion of the South West Pipeline' [online document], The Australian Pipeliner.

33 Offshore Energy (2022), 'Venice Energy speeds up Outer Harbor LNG construction' [online document], Offshore Energy.

34 Australian Financial Review (2022), 'Esso plans $400m gas production expansion' [online document], Australian Financial Review.

35 NS Energy (2022), 'ExxonMobil, BHP to invest $291m to further develop Kipper gas field' [online document], NS Energy.

1.6.2. Cooper Basin expansion

In June 2022 Santos and its joint venture partner Beach Energy announced that they have committed to a program of works which aims to deliver an additional 15 TJ of gas per day from the Cooper basin to the east coast market by the end of 2022.[36] Santos anticipates the program of works to produce around 1.1 PJ in 2022 and 5.8 PJ in 2023 across both JV parties.[37] This increased production has not been incorporated into our supply-demand balance for 2023, and may go some way to alleviating the forecast shortfall.

1.6.3. Cooper Energy expansion

Cooper Energy have reported higher than expected gas production from the Orbost Gas Processing Plant. This indicates that there could be additional gas supply coming into the east coast gas market in 2023 which could partially address the predicted shortfall.[38]

Separately, Cooper Energy have also announced that they have acquired the Orbost Gas Processing Plant from APA for $270 - 330 million.[39]

1.6.4. Golden Beach project

The Australian Government has agreed to provide GB Energy a $32 million loan to accelerate the development of the Golden Beach gas production and storage project. This project is expected to produce gas for the domestic market over a two-year period before converting to an underground gas storage facility. The capacity of the storage facility is expected to be around 12.5 PJ, which will help boost storage capacity in the southern states.[40]

GB Energy currently expect first gas from the Golden Beach project in mid-2024.

1.6.5. APA's South West Pipeline

APA has announced a $60 million expansion of the South West Pipeline in Victoria, which is expected to come online in 2023. This expansion will involve the construction of an additional compression facility and is expected to increase the security of supply in Victoria.[41] This investment is in addition to the $270 million expansions of the South West Queensland Pipeline and the Moomba to Sydney Pipeline, which were announced in 2021.

1.6.6. Australian Government funding

In the Federal Budget handed down in March 2022, the Australian Government provided $48 million in funding for projects to support the National Gas Infrastructure Plan's priority actions. The projects that have been provided funding include:[42]

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36 Santos (2022), 'Additional Cooper basin rig to boost gas supply' [online document], Santos.

37 Santos have noted in correspondence that "“This is a forward looking statement that is subject to risk factors associated with the oil and gas industry and does not represent a guarantee or prediction of future performance, and involves known and unknown risks, uncertainties and other factors, many of which are beyond Santos’ control, and which may cause actual results to differ materially from those expressed in the statement".

38 Cooper Energy (2022), 'Guidance and operations update' [online document], Cooper Energy.

39 Cooper Energy (2022), 'Acquisition of the Orbost Gas Processing Plant', [online document], Cooper Energy.

40 Australian Financial Review (2022), '$32m federal loan to boost east coast gas' [online document], Australian Financial Review.

41 The Australian Pipeliner (2022), '$60 million expansion of the South West Pipeline' [online document], The Australian Pipeliner.

42 Department of Industry, Science, Energy and Resources (2022), 'Accelerating priority natural gas infrastructure projects' [online document], Department of Industry, Science, Energy and Resources.

- Central Petroleum's Range Project in Queensland, with APA awarded funding to accelerate the development of the gas infrastructure required to bring this project online
- Transition Energy's Gas Infrastructure Hub project in the Bowen Basin
- Lochard Energy's Heytesbury underground gas storage project, which will result in an expansion of gas storage capacity in Victoria
- APA's Surat Hub project, Stage 2 East Coast Gas Grid expansion and South West Pipeline expansion, which together will result in the expansion of capacity on a number of key pipelines in Queensland, NSW and Victoria
- a feasibility study into the most efficient infrastructure to deliver natural gas from Beetaloo to the east coast market.

In addition to these projects, the Australian and Northern Territory Governments announced in early April that they had agreed to provide $872 million in funding to accelerate gas production from Beetaloo.[43]

1.6.7. LNG import terminals

Venice Energy announced in March 2022 that it is accelerating the development of its $250 million LNG import terminal in Port Adelaide, with construction expected to commence in the second half of 2022.[44] This follows a decision by the South Australian Government to approve the development of the facility, making it the second LNG import terminal to have received the relevant approvals in Australia.

AIE's Port Kembla import terminal has recently completed its site preparation phase. The project is scheduled to be completed by mid-2023, with imports to commence in 2024.[45]

There have been no major public updates since our last interim report on any of the other LNG import terminals proposed in the east coast gas market.

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43 ABC (2022), ''NT and federal government sign off on funding deal to accelerate Beetaloo Basin gas production' [online document], ABC.

44 Offshore Energy (2022), 'Venice Energy speeds up Outer Harbor LNG construction' [online document], Offshore Energy.

45 Australian Industrial Energy (2022), ''Demolition Phase Completed' [online document], Australian Industrial Energy, and direct communication with AIE.

2. Domestic Price Outlook

Key points

- In late 2021/early 2022 the prices being offered in the domestic east coast gas market for 2023 supply contracts (Gas Supply Agreements, GSAs) were below those being paid in international spot markets for LNG, and below prices in domestic spot markets. However, the ACCC is concerned at the recent extreme price increases observed in spot markets in Australia and overseas, and their implications for future contract prices in the east coast gas market.
- Prices reported in this chapter relate to information we collected from gas suppliers (producers and retailers) up to 16 February 2022. We have also looked at more recent public information in relation to prices in the domestic facilitated gas spot markets.
- Prices offered for 2023 supply by both gas producers and gas retailers[46] increased over the second half of 2021, mostly within the range of $8/GJ to $16/GJ.
    - Prices offered for 2023 supply by gas producers increased from a range of $6.79/GJ - $11.40/GJ in the first half to 2021 to between $7.33/GJ and $16.33/GJ in late 2021 and early 2022.
    - Over this period, prices offered by retailers also increased from $8.25 - $10.87/GJ to $8.52 - $13.46/GJ.
    - Quantity weighted average prices offered by producers was $10.49 between September 2021 and February 2022, compared to $9.75 for prices offered by retailers. This is the first time we have observed average producer offers priced higher than average retail offers.
- Prices offered for 2023 supply were mostly higher than offers made at the same time for supply in 2022. LNG exporters made a small number of offers for 2022 supply at significantly higher prices, between $20/GJ and $25/GJ.
- The expected LNG netback price for 2023 supply increased sharply in the second half of 2021 and has increased further since February 2022. Prices offered by producers for supply in Queensland largely tracked expected LNG netback prices higher. However, prices offered for supply in southern states were lower.
- The number of offers to the domestic market for 2023 supply is higher compared to the number of offers we observed at the same time last year. However, these offers have resulted in significantly fewer GSAs being entered into.
- Prices payable under Gas Supply Agreements (GSAs) executed by producers between September 2021 and February 2022 for supply to southern states in 2023 averaged $9.25/GJ. Average prices payable under GSAs executed by retailers over the same period was at $10.01/GJ.
- A well functioning HoA with LNG exporters could ensure that LNG exporters make gas broadly and transparently available to all domestic C&I users (and gas retailers) at demonstrably competitive prices, in volumes and for periods suitable to buyers' needs, and with sufficient notice.
- We continue to have concerns that under the current HoA some LNG exporters are not engaging with the domestic market in the spirit in which the HoA was signed.
    - In some instances, some LNG exporters are not counteroffering to parties that bid into EOIs.
    - Reasonable notice does not appear to always be provided to domestic market participants, such that offers cannot in practice culminate in a supply agreement.
    - An LNG exporter is offering gas to the domestic market at prices it cannot reasonably expect to receive when selling gas to the international market.

[46] This includes retailers like Origin, AGL and EnergyAustralia, which retail both electricity and gas, primarily to retail and small business consumers and small to medium C&I users. Users will often prefer to obtain gas from retailers, so that transportation, risk/hedging and management of daily fluctuations is gas usage is looked after by the retailer rather than the user.

2.1. Introduction

This chapter presents information on wholesale gas commodity prices in the east coast gas market for supply in 2023.[47]

Specifically, the ACCC reports on:

- prices offered and bids received by gas producers and retailers (section 2.3.1)
- prices offered in Queensland and the southern states relative to expected LNG netback prices (section 2.3.2)
- prices agreed by gas producers and retailers (section 2.3.1)
- the level of flexibility agreed by producers and retailers (section 2.4.1).

The above reporting is based on information received in response to compulsory information notices, and reflects offers, bids and contracts agreed up to 16 February 2022.

This chapter also assesses compliance with the Heads of Agreement between the east coast LNG exporters and the Australian Government (section 2.4.2).

This is the first report where we analyse wholesale gas commodity prices for supply in 2023. Our completed analysis of wholesale gas commodity prices for supply in 2022 is in Appendix A.

Prices reported in this chapter reflect wholesale gas commodity prices in offers, bids and gas supply agreements (GSAs) which have a term of at least 12 months, an annual contract quantity (ACQ) of at least 0.5 PJ, and are made or entered into at arm's length. A complete explanation of the ACCC's approach to reporting on prices is presented in appendix B.

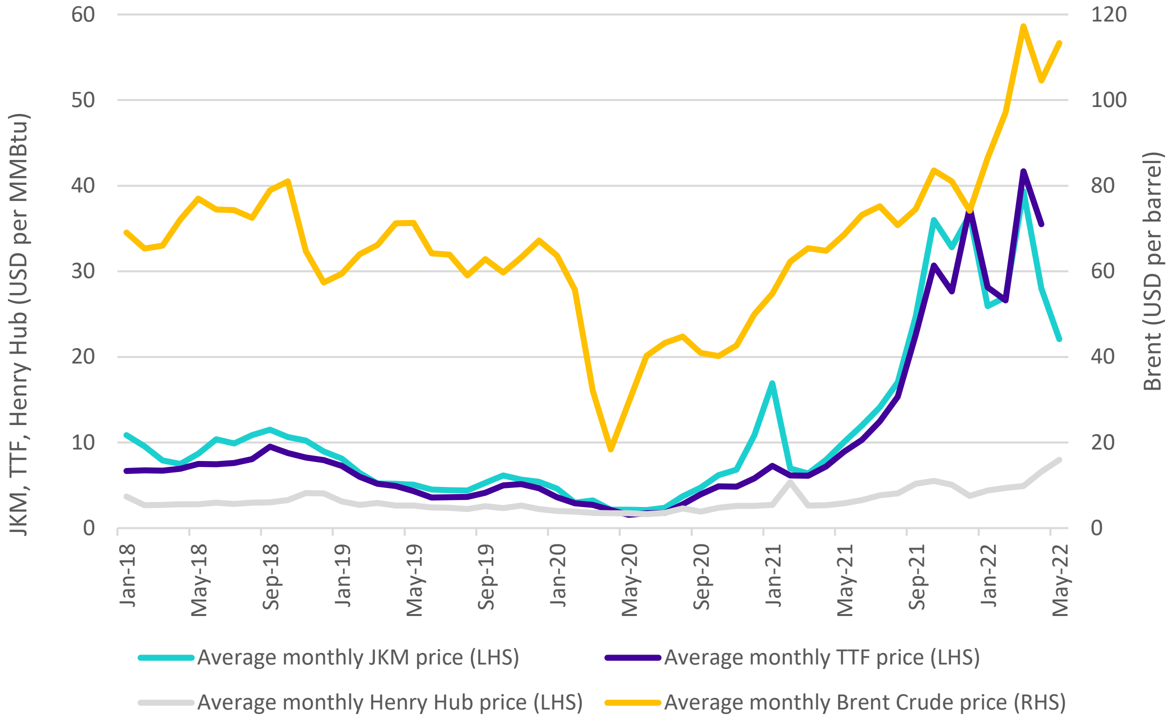
Where the ACCC reports on an average price in this chapter, it is a quantity-weighted average wholesale gas commodity price.

2.2. Recent trends in international oil and LNG prices and domestic short term market prices

In our previous interim report, we considered the changes of international LNG and oil prices, as well as the domestic short term markets given their influence on GSA prices in the east coast gas market. We have continued reporting on these prices given the ongoing volatility and uncertainty experienced in global markets.

[47] The east coast gas market consists of Queensland, New South Wales, Victoria, South Australia, the Australian Capital Territory and Tasmania.

Chart 2.1: Historical Brent Crude and International gas prices



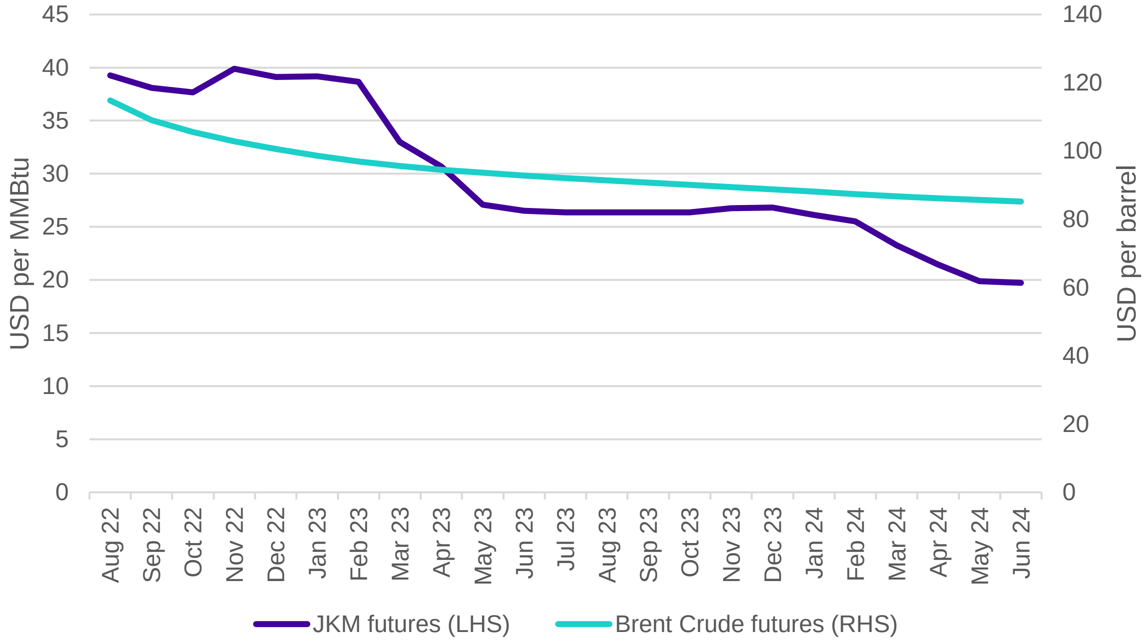
Source: ICE (JKM), Argus (TTF), S&P Global Platts (Henry Hub), EIA (Brent Crude), ACCC analysis.

Chart 2.1 presents historical prices for Brent crude and international gas markets. As discussed in previous inquiry reports and our LNG netback price series review, LNG prices influence domestic suppliers' opportunity cost of supplying gas to the domestic market and therefore influence domestic prices. Our review of supplier pricing strategies found that oil prices have also been a key factor in domestic pricing in recent years.

Since September 2021, Brent crude prices have continued to increase, reaching a high in May with an average daily price of USD110. JKM, following a record high in September 2021, experienced extreme daily volatility. Prices fell to USD26 per MMBtu in January before again reaching a record high in March. Since March, prices for JKM have fallen to around USD22 per MMBtu.

European and Asian gas markets have been highly correlated, with TTF and JKM tracking closely. Henry Hub prices have also increased, though not in line with other international markets. Henry Hub reached a monthly average price of USD7.98 in May 2022.

Chart 2.2: Forward estimates of JKM, Brent Crude

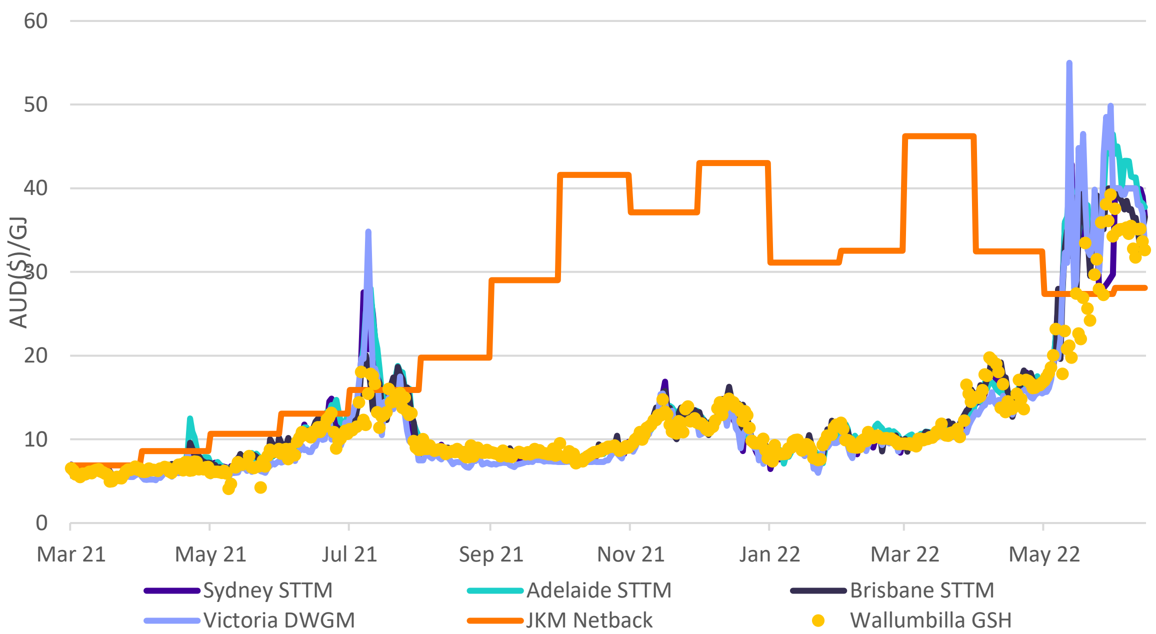


Source: Bloomberg, ACCC analysis.

Note: JKM futures (calculated as at 29 June) & Brent futures (calculated as at 30 June) are presented as monthly averages.

Chart 2.2 sets out the estimated forward prices for JKM and Brent Crude calculated as at end June 2022. Both JKM and Brent Crude are forecast to remain elevated over the next two years. The JKM price is expected to remain particularly high over the second half of 2022. This is likely due to strong forecast demand over the European and Asian winter, and tight LNG supply.

Chart 2.3: Domestic short term market prices



Source: AEMO, ACCC (JKM netback), S&P Global Platts.

Following domestic prices exceeding LNG netback in July 2021, which we reported on in our January 2022 report, domestic prices de-linked from LNG netback and did not experience the rapid price increases seen in international gas markets.

Domestic prices however began increasing from the end of March 2022, exceeding falling LNG netback prices in May 2022. This has been driven in part by cold weather, electricity generator outages and high international prices for coal and gas.

AEMO introduced price caps of $40/GJ in Sydney and Brisbane markets following the retailer of last resort event caused by Weston Energy's suspension from trading on 24 May 2022.[48] AEMO also imposed a price cap of $40/GJ in Victoria beginning 31 May 2022 due to sustained high prices in the previous week causing the cumulative price threshold to be reached.[49]

We are concerned that higher international and domestic prices may flow through to long term GSAs in the domestic market.

2.3. Prices offered for supply in 2023 have increased, influenced by significant increases in LNG netback

In reporting on offers made and bids received by suppliers, we included only those offers and bids that contain clear indications of price, quantity, supply start and end dates, and estimate the price for each offer and bid using the approach outlined in appendix B.

The analysis of offer and bid prices in this chapter is intended to provide an indication of price trends over time. As explained in appendix B, the prices of individual offers and bids are not necessarily comparable as they can differ in non-price aspects, such as delivery location, quantity, contract term and contract flexibility. Offer and bid pricing in some instances may also reflect seasonal price fluctuations, linkages to prices of other commodities (such as oil), price expectations over the length of the contract (not only the supply year in discussion) or, in the case of GPG, conditions in the electricity market.

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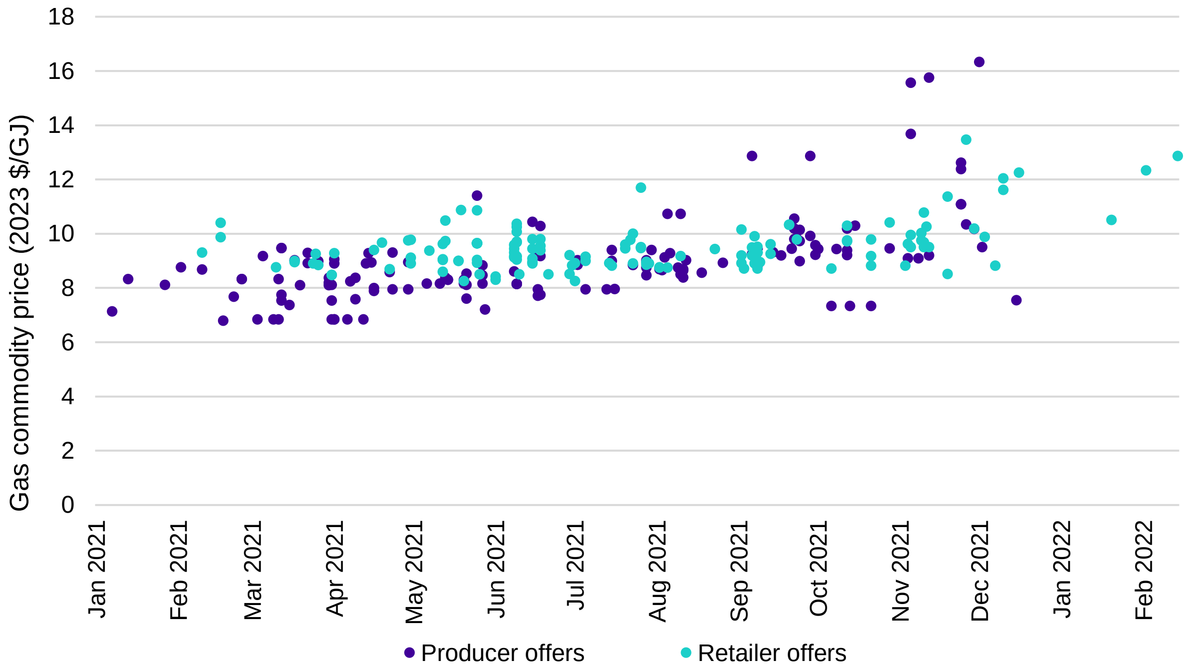
48 Rule 428(1)(d) of the National Gas Rules requires AEMO to put in place an administered price cap for a hub if AEMO becomes aware that a Retailer of Last Resort (RoLR) will assume responsibility for customers of an STTM User at the hub with effect from that gas day, and AEMO determines that to be a minor retailer of last resort event in accordance with the STTM Procedures.

49 The cumulative price threshold is $1,400/GJ and is calculated as the sum of the marginal clearing price over 35 consecutive scheduling intervals (7 gas days). If the CPT is breached, the market price is capped at the Administered Price Cap, currently $40/GJ.

2.3.1. Prices offered for supply in 2023 increased throughout 2021

Chart 2.4 shows offers made by producers and retailers for 2023 supply over the period from 1 January 2021 to 16 February 2022.

Chart 2.4: Gas commodity prices (2023$/GJ) offered in the east coast gas market for 2023 supply



Source: ACCC analysis of offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA.

Prices offered for supply in 2023 have increased over the course of 2021, with price increases accelerating from around August. Prices offered around $16/GJ between November and December 2021 are the highest prices we have reported for supply since our April 2019 interim report. In that report we observed retailers offering prices above $16/GJ in early 2017 for 2019 supply.

We are very concerned at anecdotal reports of even higher prices being offered to C&I users in April and May 2022, with reports of offers as high as $21.20 (Section 3.3). We are also concerned with the extremely high prices observed in domestic spot markets since May 2022 (Section 2.2), along with high LNG prices, which may flow through to long term contract prices. The price data in this chapter includes prices for offers up to 16 February 2022, prices offered or in GSAs entered into after this time will be reported in our January 2022 interim report.

The number of offers for 2023 supply is materially higher than the number of offers for 2022 supply we reported in our July 2021 report. Producer offers increased from 87 offers for 2022 supply to 149 offers for 2023 supply. Retail offers to C&I users have also increased from 110 offers for 2022 supply to 115 offers for 2023 supply, over comparable timeframes.

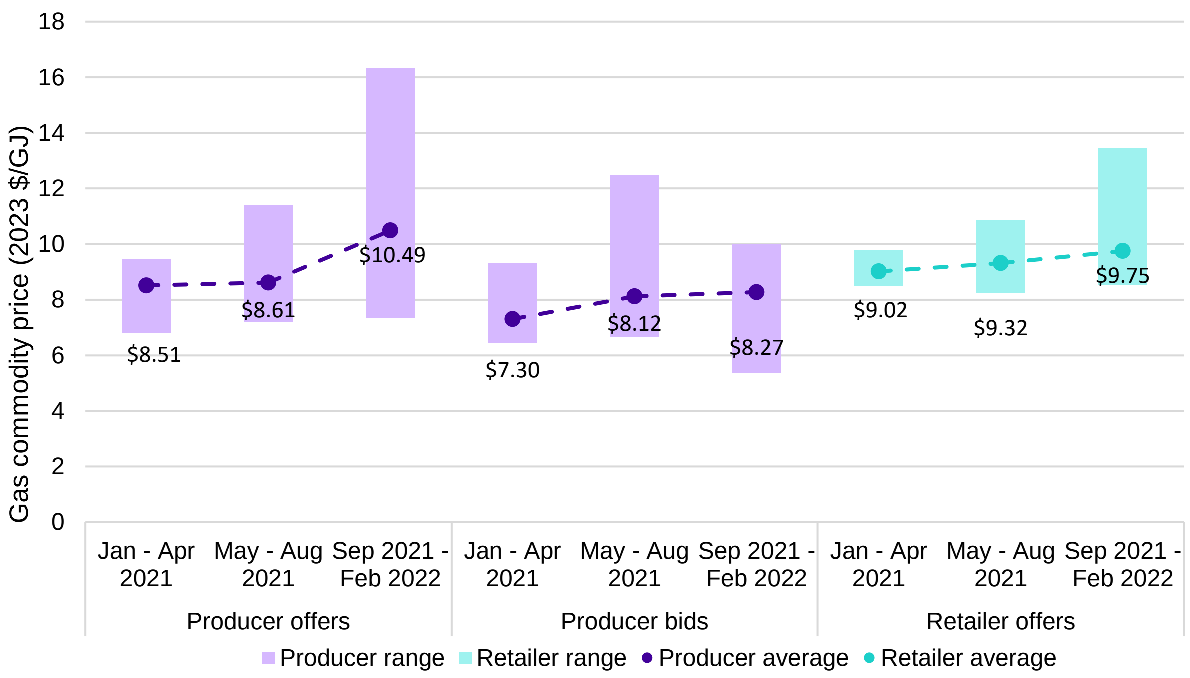
There were only three offers made for 2023 supply at the beginning of 2022. This reduction in offers is consistent with market behaviour observed in previous reports and may reflect a slowdown in business activity over the Christmas/New Year holiday period.

Chart 2.5 compares the quantity-weighted average price of offers made and bids received by producers (for all buyers) and by retailers (for all C&I users) for gas supply in 2023 in three periods:

- January 2021 to April 2021
- May 2021 to August 2021
- September 2021 to February 2022

Offers are those prices offered by a producer or retailer to a gas consumer while bids are those prices that a user has proposed to pay to a producer. (Retailers typically supply to retail small business, household users and small to medium C&I users who typically aren't in a position to counterbid to an initial offer by the retailer).

Chart 2.5: Gas commodity prices (2023$/GJ) offered and bid in the east coast gas market for 2023 supply



Source: ACCC analysis of offer information provided by suppliers.

Note: Quantity-weighted average prices are displayed below the price range. Bids made to retailers were excluded from the chart because an insufficient number of bids were made to retailers by C&I users.

Between September 2021 and February 2022, quantity weighted average prices for offers from producers increased 22% from the previous period. Similarly, prices offered by retailers increased, though to a lesser extent.

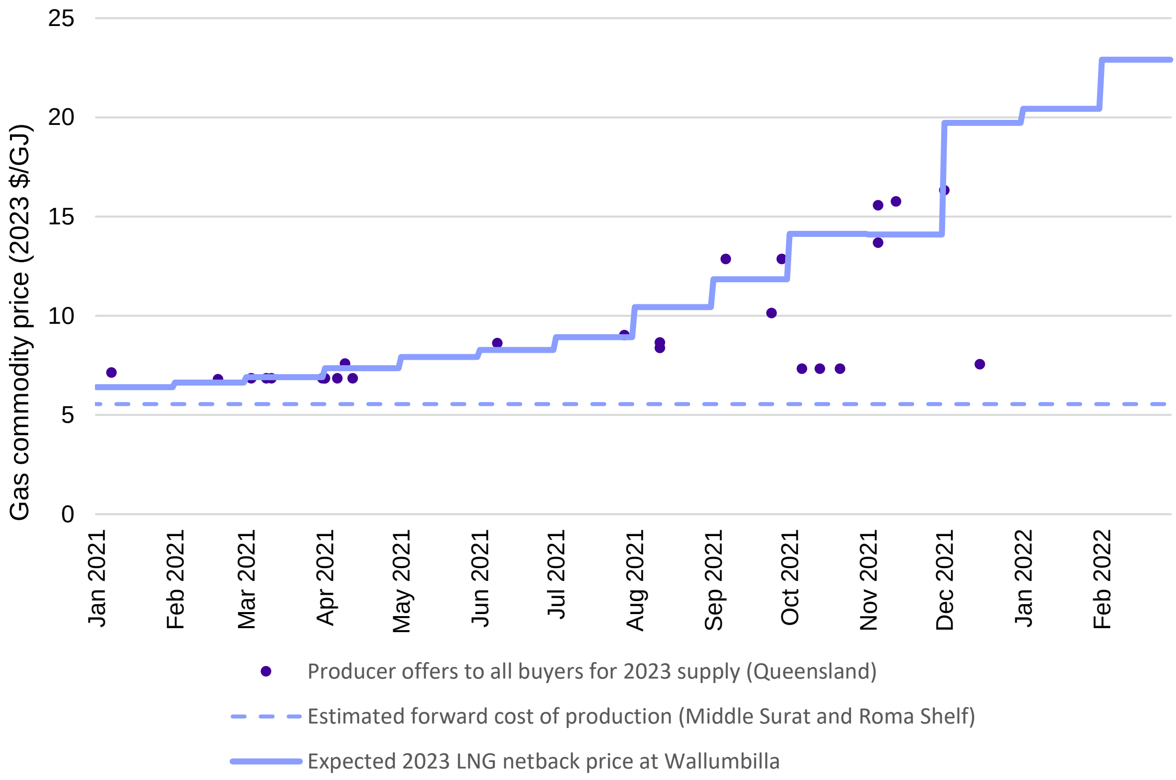
Quantity weighted average prices offered by producers exceeded those offered by retailers between September 2021 and February 2022. This is the first time we have observed average producer prices exceeding average retail prices since our inquiry began.

The quantity weighted average prices of bids received by producers increased slightly between September 2021 and February 2022 compared to the previous period. This occurred in an environment of significantly less bids which fell by around 60%.

2.3.2. Most prices offered in Queensland tracked the significant increases in LNG netback prices higher

Chart 2.6 compares offers made by producers for supply in Queensland in 2023 between 1 January 2021 and 16 February 2022 (as at the time the offer was made).

Chart 2.6: Gas commodity prices (2023$/GJ) offered by producers to all buyers for 2023 supply compared to expectations of LNG netback (Queensland)



Source: ICE, Argus, ACCC analysis of other information provided by suppliers.

Note: The above chart only includes offers that relate to contracts with a term of 1–3 years. Offers that specify pricing mechanisms linked to oil prices have been excluded.

From January 2021 to February 2022 expected LNG netback prices for 2023 supply have increased by close to 360%, reaching $22.91/GJ on average in February.

Prices offered by producers for supply in Queensland have largely tracked LNG netback prices higher. The clear outliers to this trend are the four producer offers beginning in October 2021 priced below $10/GJ. These offers reflect negotiations between two parties, in which one party is constrained through contractual obligation from offering the gas to the domestic market more broadly. This obligation is the result of exclusivity provisions set out in a GSA. We have considered the impact of exclusivity provisions on competition in our review of upstream competition and timeliness of supply set out in Chapter 5.

Alongside increases in the prices offered set out in Chart 2.6, we have observed additional LNG exporter EOI processes with price guidance referencing the ACCC LNG netback price series as a comparable marker for what these producers would be willing to accept for 2023 supply.

As well as increases in the price of offers made by producers for 2023 supply, the second half of 2021 saw a similar increase in the price of offers made for 2022 supply. These offers, set out in Appendix A, show two distinct trends.

- Offers by LNG exporters tracked significantly higher, with offers around $20 to $25/GJ reported, alongside significant rises in expected LNG netback prices.
- Offers by other producers increased, though not in line with expected LNG netback prices.

In our most recent C&I user survey, some users noted they had received offers above what it would cost them to switch their plant operations the use of alternative fuels, such as biomethane or diesel. Spot exposed manufacturers have also considered ceasing operations (Chapter 3). If high international and domestic spot prices persist and flow through to long term contracts, the prospect of C&I closure and longer-term demand destruction look increasingly likely.

Box 2.1: Incitec Pivot Limited

On 8 November 2021, Incitec Pivot Limited (IPL) announced that it will close its Gibson Island fertiliser manufacturing plant effective from December 2022. IPL stated the reason for the closure decision was the inability "to secure affordable gas supply beyond the end of our current gas contract".[50]

On 7 February 2022, the ACCC received a direction from the then Assistant Treasurer to examine IPL's gas tender process for its Gibson Island plant.[51] We have used information on bids and offers received from producers in response to compulsory information notices, in addition to information voluntarily provided by IPL to conduct this examination.

IPL's current GSA used to supply its Gibson Island plant was executed in mid-2019 for supply from early 2020 to late 2022. The contract price agreed to at the time was at a discount to contemporaneous market prices.

In late 2021, IPL conducted a request for proposal (RFP), approaching 13 parties seeking to contract 13.8 PJ/a of supply from mid-2023 to mid-2027. The RFP process resulted in 7 parties offering gas for supply for periods between 2023 to 2027. However, many of the offers provided a lower volume than IPL's total annual volume requirements and fell short of the duration requirements.

The prices offered in response to the RFP and the subsequent bidding process varied due to different pricing mechanisms. While IPL did not receive the price discounts it had received in previous contracts, the prices it was offered were in line with contemporaneous domestic market prices.

IPL proceeded to negotiate with three of the offering parties, however these negotiations did not result in IPL entering any new GSAs for the Gibson Island plant.

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50 Incitec Pivot Limited, 'Gibson Island manufacturing operations to cease at end of 2022', 8 November 2021, https://www.incitecpivot.com.au/about-us/about-incitec-pivot-limited/media/gibson-island-manufacturing-operations-to-cease-at-end-of-2022

51 Letter from the Hon Michael Sukkar MP to Rod Sims, 7 February 2022, https://www.accc.gov.au/system/files/Letter%20from%20the%20Hon%20Michael%20Sukkar%20MP%20to%20Rod%20Sims%20-%20gas%20inquiry.pdf

2.3.3. Prices offered in the southern states trended towards the seller alternative levels in mid-2021 following it higher to end 2021

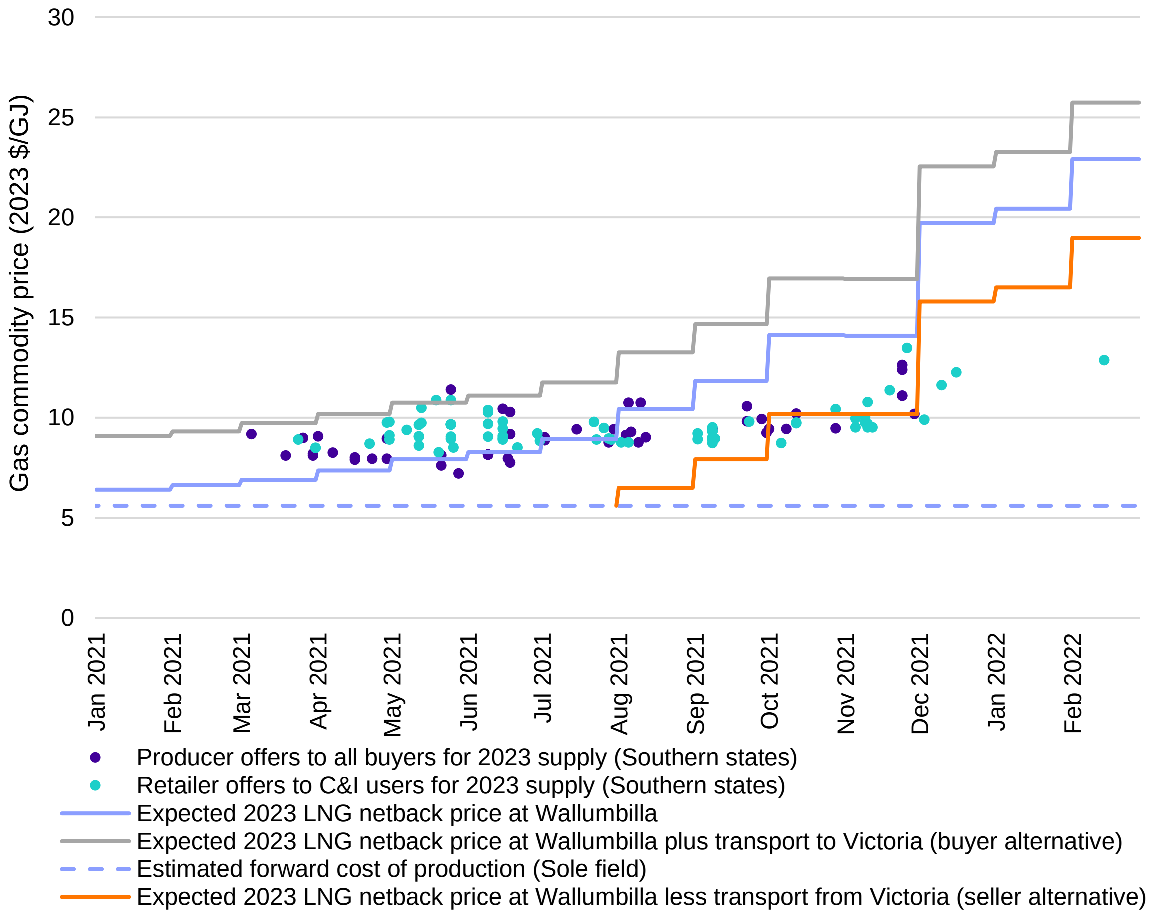
Chart 2.7 compares offers by producers and retailers in the southern states for 2023 supply made between 1 January 2021 and 16 February 2022 with:

- expectations of 2023 LNG netback, and the buyer and seller alternative prices, as at the time the offer was made
- the estimated forward costs of production for marginal gas production in the southern states.

As noted in previous reports, prices in the southern states in a well-functioning market are expected to fall between:

- the buyer alternative (representing a ceiling in negotiations) – the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location
- the seller alternative (representing a floor in negotiations) – the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla (from the south) or the forward cost of production

Chart 2.7: Gas commodity prices (2023$/GJ) offered by producers to all buyers, and retailers to C&I users for 2023 supply against expectations of LNG netback (southern states)



Source: ICE, Argus, ACCC analysis of other information provided by suppliers.

Note: The above chart only includes offers that relate to contracts with a term of 1–3 years. Offers that specify pricing mechanisms linked to oil prices have been excluded.

Throughout the first half of 2021, prices offered in the southern states for 2023 supply primarily fell between the expected LNG netback price and the buyer alternative. Following sharp increases in the expected LNG netback price in the second half of 2021, offers in the southern states increased, though not as high as producer offers in Queensland.

Prices offered in the southern states in the second half of 2021 trended towards the seller alternative, clustering around $10/GJ, before tracking the seller alternative higher. Due to the reduced number of offers in the beginning of 2022, there is insufficient data to conclude whether prices offered continued to track the seller alternative.

In section 2.3.1 we note that for the first time since the inquiry began prices offered by producers exceeded those offered by retailers, on average. Charts 2.6 and 2.7 suggest that this was driven in part by producer offers in Queensland increasing in line with expected LNG netback prices, with retailer offers not increasing as aggressively.

Our review of supplier pricing strategies found that some suppliers appear to have been influenced in their domestic market pricing by a perceived threat of regulatory intervention at prices above $10/GJ. We noted in our January 2022 report that this may have been a factor in domestic prices offered for 2022 supply remaining below $10/GJ and not tracking LNG netback prices higher. Following further increases to the LNG netback price, several domestic offers for 2022 and 2023 supply in Queensland and the Southern states have exceed $10/GJ, indicating that this perceived threat is playing a less important role in suppliers' pricing.

2.4. Prices payable for supply in 2023 have increased under both fixed price and commodity linked GSAs

We report on prices payable under GSAs to provide an indication of the price medium-to-large gas buyers and suppliers on the east coast are expected to pay and receive under contracts for supply in the short to medium-term. Similarly, we report on the average take or-pay multiplier and load factor to provide an indication of the levels of volume flexibility which have been agreed to.

This section analyses prices payable and volume flexibility under GSAs for supply in 2023 that were entered into between 1 January 2021 and 16 February 2022. GSAs in this analysis:

- are entered into by producers with all buyers, or by retailers with C&I users and gas powered generators
- have fixed prices or prices linked to a commodity price index, such as Brent Crude oil
- have an ACQ of at least 0.5 PJ and a term of at least 12 months.

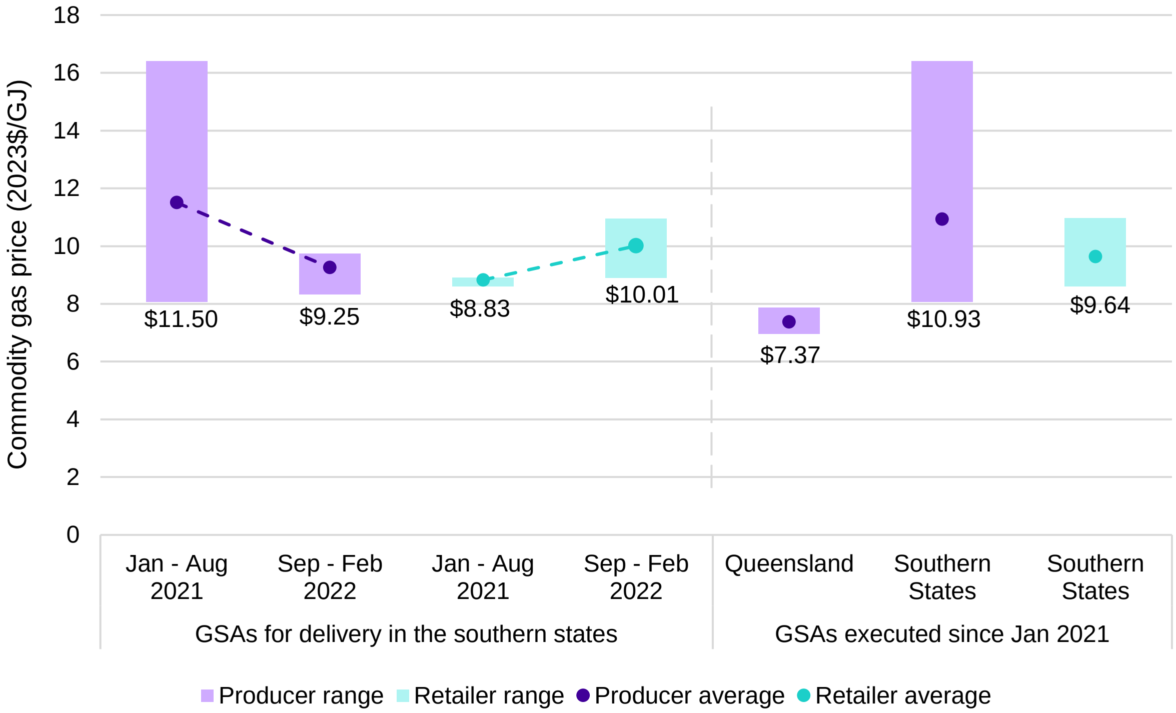
As with the analysis of bids and offers, we estimate prices under GSAs using assumptions relating to a number of variables, including the AUD/USD exchange rate, the consumer price index, and the price of oil and LNG on international spot markets. However, while bids and offers are priced using expectations of these variables at the time the bid or offer was made, GSA prices payable are estimated based on current market expectations for the relevant supply year.

2.4.1. Prices payable for supply in 2023

Chart 2.8 presents quantity-weighted average wholesale gas commodity prices expected to be paid under GSAs entered into by producers and retailers for delivery in the east coast gas market in 2023.

The left hand side of this chart compares average prices payable under GSAs entered into by producers and retailers in the southern states between January 2021 and August 2021 with those entered into between September 2021 and February 2022. The right hand side aggregates this information over January 2021 to February 2022 and presents prices payable under GSAs entered into by producers for delivery in Queensland.

Chart 2.8: Expected gas commodity prices (2023 $/GJ) payable under GSAs entered in the east coast gas market for 2023 supply



Source: ACCC analysis of information provided by suppliers.

Note: Expected prices payable under GSAs executed by retailers in Queensland were excluded from this chart because an insufficient number of GSAs were executed between retailers and C&I users for supply in Queensland.
Pricing model last updated on 14 June 2022.

Average prices agreed by producers for delivery in the southern states in 2023 were $9.25/GJ under GSAs executed between September 2021 and February 2022. Comparing the January to August 2021 and the September to February 2022 periods, average prices agreed by retailers in the southern states rose by 13.4% to $10.01/GJ.

The difference between average prices payable under producer and retailer GSAs executed over these two periods reflects the influence of a number of oil linked GSAs entered into with producers between January 2021 to August 2021. Prices payable under oil linked contracts have increased significantly since they were executed, following the increase in Brent Crude oil futures. If only fixed price GSAs were included for analysis, average prices payable under producer GSAs executed between January 2021 and August 2021 would fall to $8.68/GJ.

This suggests an underlying increase in average prices payable from producer GSAs in the southern states. Taking this into account results in a 6.6% increase in average agreed prices from producer GSAs between the January to August 2021 and the September to February 2022 periods.

This observation also highlights how a relatively small number of oil-linked contracts can affect average prices payable. We do not have full year data for supply for 2023, but we can look at the division of GSAs by pricing mechanism for 2022 supply.

Table 2.1 illustrates the division of GSAs by pricing mechanism for delivery in 2022. The table shows that even though fixed price GSAs dominate by number (91%), almost half of contracted volumes in 2022 were linked to oil. This example highlights the level of influence oil linked contracts can have over GSA prices in the east coast gas market. High volume oil linked contracts coupled with increasing Brent Crude prices can increase average delivered prices significantly.

Table 2.1: GSAs by pricing mechanism

	Fixed Price	Brent Crude	Total
2022 % Count	91%	9%	100%
2022 % Quantity	57%	43%	100%

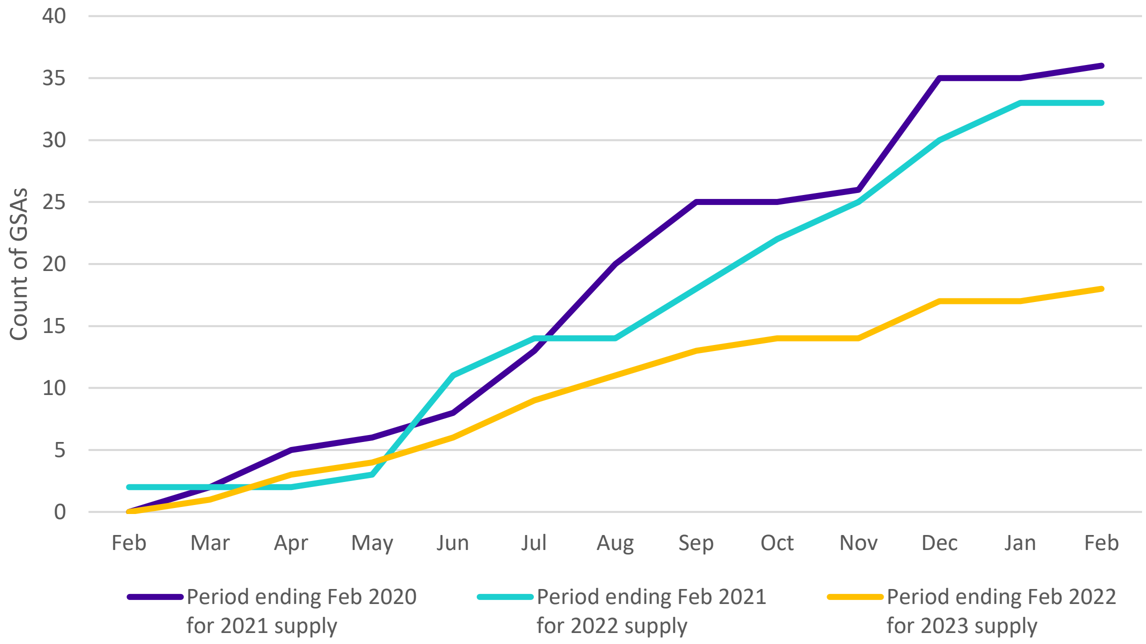
Source: ACCC analysis of information provided by suppliers

Note: Table 2.1 separates GSAs by pricing mechanism for contracts executed between January 2020 to December 2021 for supply in 2022. It does not include information from contracts executed prior to 2020 for supply in 2022. Additionally, only contracts which met the inclusion criteria as set out in section 2.6 are included in the figures, e.g. 0.5 PJ or greater for a supply duration of 12 months or more.

Chart 2.8 also compares average prices agreed for supply in 2023 under all GSAs executed between January 2020 and February 2021. Average prices payable for 2023 supply are expected to be $7.37/GJ under producer GSAs for delivery in Queensland, $10.93/GJ under producer GSAs for delivery in the southern states, and $9.64/GJ under retailer GSAs for delivery in the southern states. If only fixed price GSAs were included for analysis, average prices payable under producers GSAs executed between January 2021 and February 2022 for the southern states would be $8.92/GJ. Hence, over this period, average prices payable for supply in 2023 are expected to be lowest under producer GSAs for delivery in the Queensland, and highest under producer GSAs for delivery in the southern states.

Chart 2.9 shows that there has been a fall in the number of GSAs executed for 2023 supply over the past 12 months compared to GSAs executed for 2021 and 2022 supply over comparable timeframes. This reflects a decline in the number of GSAs agreed by both producers and retailers. This decline in contracting activity for 2023 supply comes despite the increased number of offers being made (section 2.3.1) and may indicate that buyers have been unwilling to agree to the higher prices that they are being offered.

Chart 2.9: The cumulative number of GSAs agreed for supply the following year



Source: ACCC analysis of information provided by suppliers

2.4.2. Flexibility

This section reports on quantity-weighted average take-or-pay multipliers and load factors in GSAs. The take-or-pay multiplier and the load factor are key terms and conditions in GSAs that, in practice, provide buyers with flexibility in how they manage their gas usage.

Chart 2.10 shows average take-or-pay multipliers and load factors under GSAs for supply in 2023 which were executed between January 2021 and February 2022.

Chart 2.10: Average load factor and take-or-pay multiplier under GSAs entered in the east coast gas market for 2023 supply

Source: ACCC analysis of information provided by suppliers.

Note: Average take-or-pay multipliers and load factors under GSAs executed by retailers in Queensland were excluded from this chart because an insufficient number of GSAs were executed between retailers and C&I users for supply in Queensland.

GSAs executed by retailers in the southern states provide more flexibility on average than those executed by producers in the southern states and in Queensland. The differences in the level of flexibility offered under the different categories of GSA in chart 2.10 may be driven by the capability of sellers and requirements of buyers. Retailers may be in a better position to provide flexibility in GSAs to C&I gas users as they can manage changes in the demand for gas on a portfolio basis and may have access to underground or pipeline storage.

Most retailer GSAs had a take-or-pay multiplier below 80% while most producer GSAs had a take-or-pay multiplier of 90%. The difference in the average take-or-pay multiplier for producers and retailers in southern states were driven by a small number of significantly large GSAs with take-or-pay multipliers of below 80%. The average take-or-pay multiplier under producer GSAs for delivery in Queensland is significantly higher, at 90%.

Producer GSAs for delivery in Queensland had a higher load factor than producer GSAs for delivery in southern states. Retail GSAs in the southern states however had a significantly higher load factor. Most producer GSAs had a load factor of 1.00, whereas load factors agreed under retailer GSAs were much more varied.

Several C&I users have raised concerns that there are less flexible terms available for 2023 gas supply compared to those they were offered for 2022 supply. Comparing the flexibility terms between the contracts received during the reporting period for 2023 supply with the flexibility terms for 2022 supply support this view. Specifically, we can see a reduction in average retailer load factor in southern states from 1.27 in 2022 to 1.19 in 2023 (see chart A.7 for 2022 flexibility in Appendix A). Similarly, producer load factors in Queensland have fallen from an average of 1.11 in 2022 to 1.05 in 2023. The average take-or-pay multiplier in contracts with producers for delivery in southern states increased from 89% to 93% (indicating less flexible terms), whereas take-or-pay levels agreed by retailers in southern states and producers in Queensland remained broadly similar.

2.5. Heads of Agreement

Under the current Heads of Agreement (HoA) between LNG exporters and the Australian Government,[52] LNG exporters have committed to provide the ACCC with material which can be used to assess their compliance with the HoA.

The HoA is intended to ensure a secure and competitively prices gas supply for the East Coast domestic market. A well functioning HoA should ensure that LNG exporters make gas broadly and transparently available to the Australian domestic gas market:

- at demonstrably competitive prices;
- in volumes and for periods generally suitable to buyers' needs;
- and with sufficient notice.

Under the HoA LNG exporters have committed to not offer uncontracted gas to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market.

The LNG exporters have also committed that prices offered to domestic gas users will be internationally competitive, and that:

- Spot prices offered to the domestic market will have regard to the spot price LNG exporters could reasonably expect to receive for uncontracted gas in overseas markets.
- Term prices offered to the domestic market will have regard to forward term prices LNG exporters could reasonably expect to receive for uncontracted gas in overseas markets.

In our January 2022 report and consultation with LNG exporters, we raised some continued concerns about how some LNG exporters have approached demonstrating compliance with the HoA. We have seen further improvement in the behaviour of some LNG exporters in the latest documentation they have provided addressing those concerns.

However, we are still concerned that some LNG exporters are not engaging with the domestic market in the spirit in which the HoA was signed. Even if the behaviour could be proven to be technically compliant, we consider that some suppliers are not engaging with the domestic market in ways that are likely to result in supply agreements being reached and market conditions noticeably improving. In particular, we are concerned:

- With instances of LNG exporters not providing counteroffers to parties that bid into EOIs.
- That reasonable notice does not appear to always be provided to domestic market participants.
- That an LNG exporter is offering gas to the domestic market at prices it cannot reasonably expect to receive when selling uncontracted gas to the international market.

We are also concerned that some LNG exporters are not heeding ACCC concerns on what constitutes compliance if those concerns are not about their own past behaviour. We will

[52] Heads of Agreement - The Australian East Coast Domestic Gas Supply Commitment, https://www.industry.gov.au/sites/default/files/2021-01/australian-east-coast-domestic-gas-supply-commitment-heads-of-agreement.pdf

provide our findings on compliance directly to each LNG exporter to provide further guidance and encourage improved compliance with the HoA.

To avoid a domestic shortfall in 2023 LNG exporters will need to provide more gas to the domestic market at terms that make it viable for users to take up. LNG exporters have indicated they intend to export all of their uncontracted gas (167 PJ) as spot or additional cargoes in 2023. This is consistent with what we observed in 2021 with 99% of forecast uncontracted gas exported as spot or additional cargoes. LNG exporters will be required to offer this 167 PJ to the domestic market before exporting it.

We have observed LNG exporters relying in part on short term EOIs to demonstrate compliance with the HoA. We have also observed several instances of exporters not providing reasonable notice when offering gas to the domestic market through EOIs. Given these findings, we intend to closely exine in our next report whether offers to the domestic market are made with reasonable notice once an LNG exporter is aware the gas is available.

2.5.1. LNG exporter offers to the domestic market

For each cargo sold to the international market between 12 August 2021 and 16 February 2022, LNG exporters were required to provide the ACCC with evidence that equivalent gas volumes were first offered to the domestic market. Over this period, the east coast LNG exporters sold 22 spot or additional LNG cargoes to the international market, totalling around 81 PJ.

Historical spot sale information from LNG exporters shows that LNG spot sales are typically lower around the middle of the calendar year and increase towards the end of the year. This is partially explained by seasonal demand profiles with Australian demand higher in winter and European and Asian demand increasing over Australia’s warmer months.

This trend has continued with the 22 spot LNG cargoes sold exceeding the 3 spot cargoes (12 PJ) sold between 26 February 2021 and 12 August 2021. These sales also exceeded the previous periods summer cargoes, where 14 spot cargoes (53 PJ) were sold between 1 September 2020 and 26 February 2021.

Between 12 August 2021 and 16 February 2022, the east coast LNG exporters made offers to the domestic market totalling 118.4 PJ for supply in Q4 2021 or 2022, in addition to previous offers for supply. This is more than the 81 PJ exported as LNG spot sales over this period. As of 16 February 2022, the total volume of gas contracted to the domestic market by LNG exporters over this period was around 23.5 PJ, including 8 PJ contracted to other LNG exporters.

2.5.2. Domestic EOI processes

For the period of 12 August 2021 to 16 February 2022 LNG exporters have principally relied upon Expression of Interest (EOI) processes to substantiate compliance with the HoA. LNG exporter EOIs used to demonstrate compliance typically have a supply period of between 3 months, aligning with the period an LNG cargo would be exported, up to 1 – 2 years of supply.

EOIs with a term length of 3 months or less resulted in very few bids and no instances of supply to the domestic market. One LNG exporter that received only one bid in such an EOI process rejected the bid without making a counteroffer. We would expect to see LNG exporters make counteroffers to potential buyers that bid into a process in which they were invited to participate.

EOIs with a term length of 1 year or greater received a larger number of bids. However, these bids did not result in long term supply to the domestic market. This may reflect in part the price expectations of LNG exporters, particularly prices linked to LNG netback which has increased significantly over the reported period (section 2.2).

Some users raised concerns around how LNG exporter EOI processes are conducted. Some users noted that they did not believe that some LNG exporters were genuinely interested in providing actual domestic supply. Users raised concerns about:

- The short notice provided in EOI processes.
- Price levels or mechanisms, including links to LNG netback, at currently very high prices.

C&I user views are set out further in Chapter 3.

2.5.3. Short term offers

In our January 2022 report we raised concerns that one LNG exporter was primarily relying on short term offers made to the Wallumbilla Gas Supply Hub (GSH) to demonstrate compliance with the HoA. Since our last report that producer has conducted an EOI process, complementing additional short term offers it has made to the domestic market.

It is our view that offering gas into the GSH and other short-term domestic market offers can be an effective way for LNG exporters to offer and supply gas to domestic buyers, more so when complemented with other forms of market participation such as the issuing of and participation in EOIs and direct bilateral engagement.

2.5.4. Equivalent volumes with reasonable notice

Under the HoA LNG exporters have committed to not offer uncontracted gas to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market.

One LNG exporter that relied exclusively on an EOI process to demonstrate compliance with the HoA did not specify to buyers the gas volumes available in the EOI process. It is common practice to have buyers propose the volume of gas they wish to contract in an EOI process. However, the lack of a maximum available contract quantity makes it difficult to unequivocally substantiate compliance with the HoA. Specifically, it is impossible to confirm that the LNG exporter has offered equivalent volumes of gas to the domestic market before its sales to the international market.

Another LNG exporter cited an EOI process that invited a range of domestic market participants including retailers, GPG and producers to bid for a substantial quantity of gas. Gas supply, which was to be for a period of around 2 months, was to start 3 weeks after it was initially offered to the domestic market and only 7 days after responses to the EOI were due. The ACCC is concerned that this gas was not offered to the domestic market with reasonable notice. Many domestic gas users are not able to accept large volumes of gas on such short notice.

In contrast, we raised concerns in our January 2022 report that another LNG exporter had not provided reasonable notice to the domestic market when inviting users to bid for gas in an EOI. That exporter has since conducted an EOI which provided invited bidders with more reasonable timeframes between when the gas was offered and when it was to be supplied to the domestic market. We consider that this EOI better reflects the commitments agreed to under the HoA.

2.5.5. International competitiveness

Under the HoA LNG exporters have committed to offer internationally competitive prices to the domestic market, and will have regard to spot and term LNG prices they could reasonably expect to receive when making domestic offers.

In our January 2022 interim report, we raised concerns that most domestic offers made by LNG exporters for 2021 supply were priced significantly above LNG netback prices and may not have been internationally competitive. These offers occurred when LNG netback prices were low, approaching the estimated marginal forward cost of production.

Since our January 2022 report, LNG netback prices have significantly increased. Expected LNG netback prices for 2023 supply rose from $10.43/GJ in August 2021 to $22.91 in February 2022 on average. Expected LNG netback prices for 2022 supply rose higher from $6.28/GJ in August 2021 to $35.04/GJ in December 2021.

LNG exporters' long term offers for supply in 2022 and 2023 increased in line with expected LNG netback prices. Alongside long term offers, LNG EOI processes with supply periods of 3 months or less have had strong regard to LNG netback prices. One LNG exporter provided price guidance in its EOI that ‘respondents should propose with regard to LNG Netback’. Another LNG exporter indicated that ‘pricing is expected to be comparable to the ACCC’s forward prices’.

LNG exporter offers linked to expected LNG netback, particularly short term offers for late 2021 or 2022 supply were priced significantly higher than offers from other producers and other suppliers to the domestic market. However, following an EOI, one LNG exporter offered gas supply with a price link to Brent Crude. This offer, which could be considered internationally competitive, could also be considered competitive with domestic market offers from other producers. This offer did not eventuate in a contract for supply, however.

While offers priced around LNG netback could be considered internationally competitive, very few East Coast Gas Market participants are willing or able to purchase gas at these currently high prices. Some participants have also express reluctance to take on the risk of a forward price which is subject to change. This means that offers, at least at present, are unlikely to result in domestic supply. This is a function of the link between the Australian and International markets, exposing domestic customers to international prices.

2.5.6. The price LNG exporters could reasonably expect to receive

LNG exporters have agreed to offer gas to the domestic market having regard to the price they could reasonably expect to receive for uncontracted gas in overseas markets.

One LNG exporter has a long-term contract with a related party that stipulates all additional LNG cargoes the LNG exporter exports must be offered for sale to that party. The price the LNG exporter will receive for these cargoes is dependent upon a pass-through for how that cargo is on sold, and therefore may not align with international spot prices.

Since Q3 2020, the LNG exporter has sold all its additional LNG cargoes to the related party for prices significantly below the international spot price, receiving prices more in line with long term SPA's. In 2021, the average price the LNG exporter received for additional LNG cargoes was on average $30/GJ AUD below contemporaneous JKM prices.

Despite consistently achieving prices significantly below international spot prices when selling additional LNG cargoes, this LNG exporter has told the ACCC that it had regard to the ACCC netback price when making offers to the domestic market. In addition, it has told domestic customers that it expects to receive bids with price terms in line with ACCC netback when they engage with EOI process that they conduct. While JKM can generally be considered to represent the price that a gas supplier could expect to receive when selling uncontracted gas in overseas markets, this exporter appears to have been only able to reasonable expect to receive much lower prices due to an obligation to sell uncontracted gas to a related party. The ACCC is concerned that this LNG exporter has had regard to prices far above what it receives, and as a result could reasonably expect to receive, for uncontracted gas in overseas markets.

2.5.7. LNG exporter consideration of LNG prices

LNG exporters have also committed to providing the ACCC with the price expectations and assumptions for international spot or term markets used for each offer to demonstrate compliance with the HoA. While noting the concerns that the ACCC has described above regarding the specific prices regarded by one exporter, LNG exporters have complied with the obligation to provide this information, providing the ACCC with information demonstrating if and how the exporter had regard to international prices for all offers to the domestic market made between 12 August 2021 and 16 February 2022.

For offers that had regard to international prices, LNG exporters detailed methodologies and values for calculating those prices. For offers that did not have regard to international prices LNG exporters indicated why, and any domestic price or other considerations for each offer.

3. Commercial and Industrial (C&I) user experience

Key points

- C&I users (users) reported a substantial jump in offer prices. Some users have told us that prices in international markets have translated into higher contract prices sooner than they expected.
- Recent and unprecedented price increases in facilitated gas markets and the associated market exit of Weston Energy forced users to fall under the Retailer of Last Resort (RoLR) arrangements, resulting in AEMO imposing a price cap of $40/GJ in Brisbane, Sydney and Victoria. Had AEMO not intervened, wholesale spot prices were forecast to reach up to $800/GJ (in Victoria).
- The significantly higher prices reported in recent months for contract offers, alongside record high spot prices, highlight greater risks of C&I closure and longer-term demand destruction. In June 2022, Advance Bricks in regional Victoria announced its closure and textile company Flickers and plastic producer Qenos have signalled their operations may also have to close.
- Concerns about supplier behaviour reported in the January 2022 interim report have intensified. Users report suppliers are unwilling to negotiate offers and are offering reduced flexibility in non-price terms.
- Users expressed concerns over the intent, legitimacy and pricing mechanisms of certain supplier initiated EOI processes to offer gas to the domestic market. They also reported the use of ACCC netback and JKM-linked prices in offers from suppliers, a practice that had not previously been observed in the domestic market.
- Tight market conditions have led to users diversifying their portfolios and supply options to manage risks. These include adjusting contract positions, using storage to hedge price risks, reducing or managing spot market exposure, managing multiple contracts simultaneously and seeking alternative methods to diversify supply.
- Users are continuing to investigate options to fuel-switch. However, consistent with past reports respondents remain sceptical on the economic viability of some alternative fuels, raising concerns about costs, technical and climate policy implications.

3.1. Introduction

To inform the report, the ACCC surveyed the views of a number of gas users. Fifteen respondents provided input on their recent experiences in the east coast gas market. Most of these respondents met with the ACCC to discuss their experiences. These users have a total demand of approximately 80 PJ/a, and account for approximately 31% of forecast industrial demand. Some of the survey respondents are smaller users (demand less than 500 TJ), and the remaining have demand at or greater than 500 TJ.

The views reported in this chapter reflect information provided by the sample of C&I users that responded to our survey and/or otherwise met with the ACCC in April and May 2022. We have also been contacted by a number of C&I gas users greatly concerned with events in the facilitated gas markets in May and June 2022.

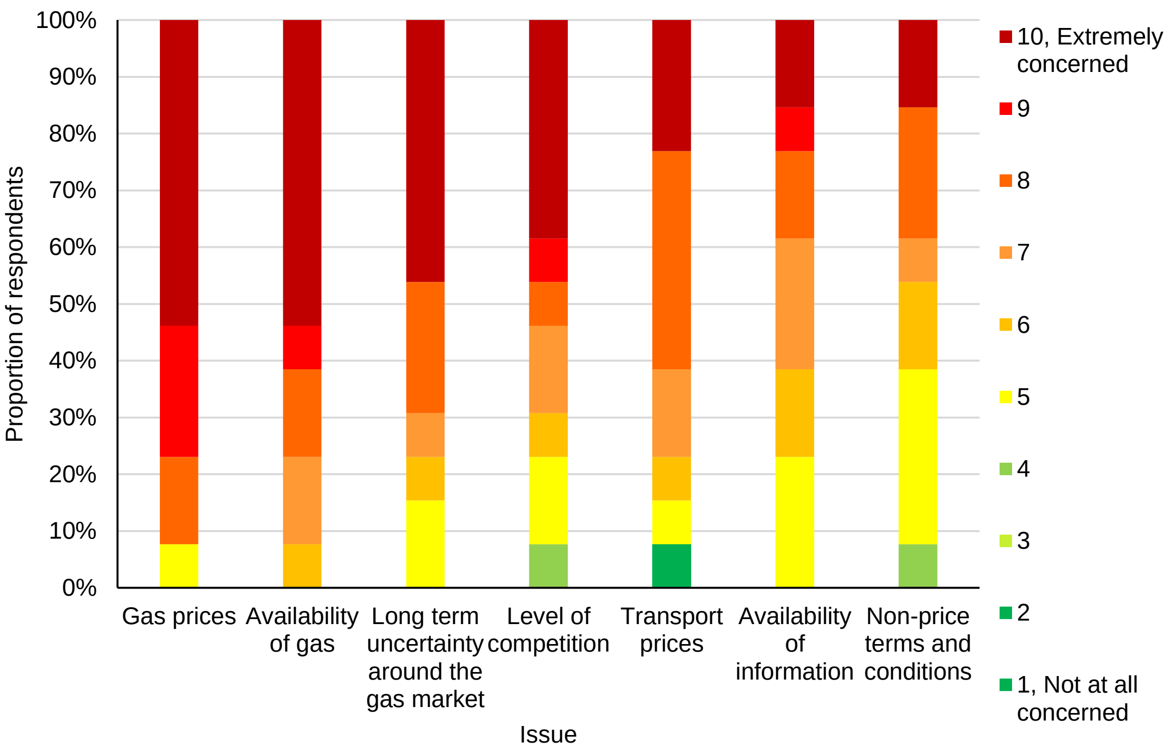
3.2. C&I users report a substantial increase in prices offered and concerns around supplier behaviour

3.2.1. Gas prices and availability of gas remain amongst users' top three concerns

Users were most concerned about gas prices and the availability of gas. Just under 70% of respondents ranked gas prices as the most or equal most concerning issue. Availability of gas was the second biggest concern.

Similar to the results of our survey in September 2021, the top three concerns of users remain gas prices, availability of gas and long-term uncertainty around the gas market. Since March 2021, an increased number of users have ranked the availability of gas as a more concerning issue compared to other issues. As outlined in Chapters 1 and 2, there is a potential for a supply shortfall in 2023, and prices offered for gas in 2023 have increased significantly, back to levels observed in 2017. Some users raised concerns around high prices in domestic facilitated markets (see section 3.3). Chart 3.1 demonstrates users' key concerns.

Chart 3.1: C&I users' rating of concerns in the east coast gas market



Source: ACCC Gas inquiry C&I user survey, March 2022.

3.2.2. Users experienced high offer prices and inflexible non-price terms

Since our last report, international and domestic market conditions have changed substantially, impacting users' experience with procuring gas.

Compared to past surveys, fewer users provided information on prices in their responses. Users reported a jump in contract prices noting offers between $11.25/GJ and $21.20/GJ for supply years 2023 and 2024, with offers at the higher end of this price range made in April and May 2022. Some users have told us that prices in international markets have translated into higher contract prices sooner than they expected, with one user noting that 'it remains to be seen whether international prices will be passed through in full'. Another user also raised concerns that the European storage policy and mandate to minimise reliance on Russian gas could drive the Australian market towards JKM parity sooner than previously expected.

Users supplying Energy Intensive Trade Exposed (EITE) products[53] into the domestic market have noted that they are unable to recover their higher input costs while prices for their international competitors may have increased in line with energy costs. Given that international energy prices have increased, we expect prices for competing imports will also increase, but this may not be observable yet.

One user commented:

> *It remains to be seen whether the recent increase in energy […] will be recovered by the market. Where we do not see any recovery in the domestic market […] the inflationary cost pressures we are experiencing cannot and have not easily been recovered in this space.*

Several users commented that gas price increases are significantly impacting their business operations. One smaller user commented that in the past they relied on the supply of cheap energy to maintain their product competitiveness. However, this advantage has eroded and there is no opportunity to pass on costs to downstream markets. This user also advised that 'if we don't get some level of control or supply in the market it will be very difficult for manufacturers in Australia'.

In our January 2022 interim report, we noted Incitec Pivot Limited's announcement that it intended to cease manufacturing at its Brisbane-based Gibson Island plant. This large manufacturer cited their inability to secure the full volume of gas required at a reasonable price as the reason for the plant closure (we have set out further analysis on the circumstances prior to the announced closure in Box 2.1, in Chapter 2).

Some other users have also experienced an inability to get sufficient volumes from a single supplier, which has resulted in additional costs.

Several users have noted a significant shift in suppliers' willingness to negotiate, with many describing a 'take it or leave it' attitude to making offers. Users further note that suppliers are allowing less flexibility in non-price terms and delaying offers.

Users advise that justification is often not provided for reduced flexibility in non-price terms. Examples cited include:

- reduced flexibility in terms, including Take or Pay, Maximum Daily Quantity, minimum Daily Quantity terms
- an 'EOI where the supplier offering gas from a declining reserve had absolute discretion over delivery days and the buyer had absolute obligation to take it (with no line of sight of which days it would be supplied)'
- receiving an offer last year where the supplier proposed to price flexibility in the contract at a price the user did not find economic.

One user also reported that a supplier requested up to five weeks to provide offers. Another user expressed frustration at frequent revisions to offers, including repricing to increase prices an hour after the acceptance of the offer. Such behaviour puts pressure on users in the current volatile market environment and poses a challenge to users' ability to secure prices. This is consistent with findings of past interim reports where users reported that short time frames were provided by producers in which to make decisions. It is often difficult for users to obtain necessary internal approvals within short time frames. One user commented that:

[53] An EITE business is impacted by high energy prices but unable to pass costs downstream due to international competition. Typical EITE products include building materials, packaging and food manufacturers and metals processing.

> *Large energy users need to budget for energy costs, making it impossible for buyers to purchase gas when a supplier only makes it available on take it or leave it terms or at short notice.*

Suppliers' behaviour in negotiations has raised users' concerns about returning to the market conditions seen in 2016-19. Larger users with existing relationships with suppliers also report experiencing such behaviour. A user advised that 'it should be mandatory for producers to make an offer when users request for quotes…there is no consideration for domestic buyers'.

Another user reports a supplier providing significantly outdated JKM data, showing prices less than $9/GJ, for a recent floating JKM-linked offer. This kind of behaviour can lead users to believe offers are more attractive than is actually the case and is particularly egregious.

Users also expressed concerns over information transparency, the way gas from declining reserves is marketed and the impacts this may have on the market. Examples include:

- concerns around declining reserves in the Bass Strait/southern states, and the pricing pressure this will place on the market (also discussed Chapter 5)
- concerns and disappointment that gas from a recent Victorian offshore expansion was fully contracted before information became available to the wider public
- a lack of transparency around announcements on the Gippsland Basin production profile and 'selectivity around how information is being disclosed'. Reporting requirements as part of the transparency reforms on reserves and resources are underway to address these concerns.[54]

High offer prices, reduced flexibility in non-price terms and suppliers' unfavourable selling practices have affected users' contracting behaviour. Despite February to April historically being a high contracting period, users appear to have found difficulties in contracting to lock in supply. The Inquiry first reported a gap in contracted load between 2022 and 2023 in the January 2021 interim report, which persisted in September 2021. In March 2021 the average contracted demand was 83 per cent for supply in 2022 while in March 2022 the average contracted demand for the next calendar year is lower at 79 per cent (See Chart 3.2).

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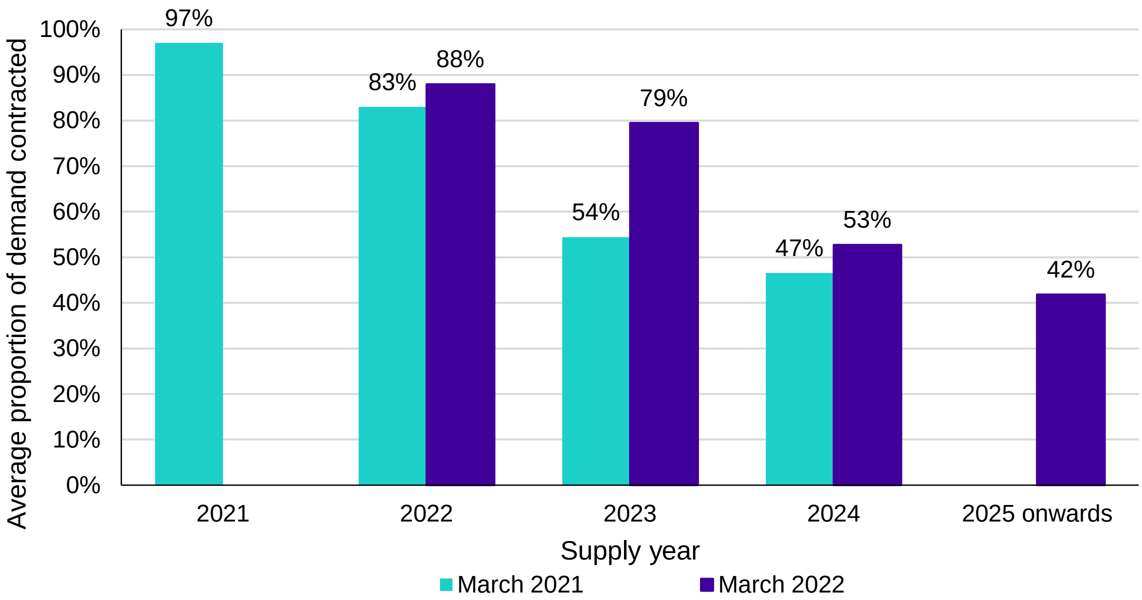
[54] See https://www.energy.gov.au/government-priorities/energy-ministers/energy-ministers-publications/regulatory-amendments-increase-transparency-gas-market#:~:text=transparency%20reforms%20that%20will%20facilitate,respond%20to%20changing%20market%20conditions.

Chart 3.2: Weighted average proportion of survey participants' demand contracted under GSAs



Source: ACCC Gas inquiry C&I user survey March 2022, March 2021.

Note: This chart sets out the weighted average proportion of users' gas demand reported to the inquiry as contracted under firm GSAs in our March 2021 and March 2022 surveys. Values in the chart are weighted by users' annual demand as reported in each survey. The values in this chart are only reflective of the users that responded to the survey, which differs over time. Total demand captured in the March 2021 and March 2022 survey was 90PJ/a and 80PJ/a respectively.

We remain concerned about the selling practices of suppliers. We note the gas supplier voluntary code of conduct (the code) was announced on 1 December 2021. The code, which applies minimum standards to all GSAs, is intended to address some of the concerns discussed above and the imbalance in bargaining power. It is disappointing that the concerns relating to supplier behaviour have intensified at a time of the pending implementation of the code. Once the code is implemented, we expect suppliers to act in good faith in negotiations with users, which should lead to greater improvements in this area. We will continue to monitor the implementation and operation of the code.

3.2.3. Users reported increased use of ACCC netback and JKM-linked prices

Users noted increased references to ACCC netback and JKM prices in both floating JKM-linked offers from suppliers and supplier-initiated EOI processes. Some suppliers have suggested that bids for fixed term GSAs should 'reference' or reflect forecast LNG netback prices.

Users note that sellers' interest in JKM or netback-linked contracts is recent and attribute it to high JKM prices. They highlighted that they did not receive JKM or netback-linked offers when JKM prices were low in the past. A user expressed frustration that sellers were using JKM references in EOIs to test buyers' willingness to pay.

According to users, JKM linkage in a price mechanism in a fixed term GSA is not an attractive option due to current high prices and the limited ability to hedge against these price movements. Users have expressed the view that price uncertainty associated with JKM-linked contracts makes them unreasonable, impractical and concerning for most industrial gas users. Respondent comments include:

> *[Suppliers] should be able to put a customer's hat on and see that a 3 year offering at JKM spot has no value in terms of risk mitigation, or comparison to alternatives. The customer could just as easily go and buy the gas on [the spot market] at JKM. These are smart people, so they (LNG exporters) know this. It makes it hard to avoid the conclusion that the offers are just a box-ticking exercise… Any advantages JKM offered with inverse linkage with northern summer/winter markets no longer persist.*
>
> *[In] some conversations we are having with sellers, they are looking for an argument [from the user] as to why they should provide a price that is not linked to JKM/ACCC netback price. We cannot bid at this. Those numbers are impossible for us to bid at.*
>
> *[The calculation in an offer where the price was linked to floating JKM price] passed all pricing risk to the customer, including foreign exchange risk; and did not factor into the formula any of the cost savings associated with supplying to a domestic customer such as lower working capital, lower transportation risk, lower health and safety risk, firm rateable demand with a lack of volatility from weather […] without the risks associated with shipping, loading and discharging an [LNG export] vessel.*
>
> *[Regarding an offer where the price was linked to the ACCC's LNG netback price] this is challenging because at the time the quote was received and given other domestic quotes at that time, a $30/GJ gas price is uncompetitive. Our industry would be unsustainable at those price levels given significant international import competition.*

One user noted that they would reluctantly deploy fuel-switching before paying current JKM/LNG netback prices.

Concerns also remain over suppliers' intent to supply gas to the domestic market. Respondents do not believe suppliers making offers linking to JKM prices have a genuine intent to supply to the domestic market, suggesting instead that suppliers are looking to maximise profits. Relevant comments are set out in Box 3.1 below (See Chapter 2 for further discussion on JKM linked pricing).

Box 3.1: User comments about supplier-initiated EOIs

- 'The EOIs are designed in a way that they are not going to get a domestic response. Seems they are very earmarked around trying to go through the motions of satisfying requirements under the Heads of Agreement. They are really trying to sell more gas overseas.'
- 'Offers feel like a box-ticking exercise to demonstrate gas has been offered to the market on export parity terms. Offers to the day ahead market at netback prices makes it feel like they are just going through the drill.'
- 'Suppliers are linking to ACCC netback price without the intention of selling to the domestic market because no one will buy it domestically at that price. They can then sell to international markets at a much higher price.'
- 'Queensland LNG producers are incentivised to export at high prices and not consider the needs of the domestic market.'
- 'If I was a seller, I would like to find the most expensive home for my gas. It's piped out of the state at 300-500TJ/day and we know where it's heading at those attractive prices…we will be swept up a little bit by that and 2023 will be messy/ugly for buyers.'
- [For producers in the southern states] 'a non-committal approach to EOIs allows them to maximise revenue' [even if they are not associated with LNG exporters].

- 'The perverse outcome of such behaviour is that the intention of the heads of agreement, which is to protect domestic consumers, is not being achieved. Whilst gas is being offered into the domestic market prior to the international market, it is being offered on terms which are unsustainable and unprofitable for local manufacturing businesses.'

Most users commented on a particular EOI initiated by an LNG exporter in March for 2023-2025 supply. The concerns about this EOI include:

- The short timeframes between the end of the response period and start of supply (responses were due by the end of April with a supply start date in May) which prevented some users from participating in the EOI process (See section 2.5 for more information on HoA).
- A user commented that over time, response windows for offers in the market have reduced from 3-4 weeks five years ago to approximately 10 days now.
- The supplier suggested to buyers that they should bid at or around LNG netback price levels in order to be competitive. This is the first-time users had seen LNG netback specifically referenced in an EOI process.
- A user mentioned that the LNG exporter was also marketing gas from the same reserve through an associated domestic retailer in volumes parallel to the EOI. This raises questions about the extent to which the LNG exporter intends to supply gas through the EOI process itself.

Several users have indicated that they do not procure gas from supplier-initiated EOIs, with one user noting that 'suppliers are forever putting them (EOI processes) out, pulling them and changing timelines'. However, the same user also advised that despite never procuring gas through this process, they would consider it a price discovery opportunity to commence conversations with suppliers and gauge interest in price and supply.

A user told us that by not providing users with certainty or committing to the gas being sold through their EOI processes, producers reserved the ability to withhold supply and raise prices to maximise revenue. As outlined in Section 2.5 and reported in our January 2022 interim report, we remain concerned about the genuineness of some offers by LNG exporters provided as evidence for compliance with the HoA.

3.3. Diversification of user portfolios/options

Tight market conditions have led to users adjusting their contracting positions to manage price risks and seeking alternative methods to diversify their gas supply.

More users in southern states are increasingly seeking storage services. Some users report seeking storage services or using existing positions at Iona to hedge against high prices. Users have reported filling their storage positions to hedge expected price spikes in facilitated markets over winter. Contrary to previous interim reports, where users considered gas from storage uneconomic, high prices since January 2022 have led to more users considering storage options (See Chapter 4 for analysis of storage prices).

Users' contracting strategies suggest there may be benefits to managing multiple contracts. One user favours fulfilling their total gas load (across multiple sites) through simultaneous smaller staggered contracts to have flexibility of supply and reduce risk, despite additional complexity. Another user noted they are exploring a portfolio approach with increased spot exposure and purchasing gas in tranches in response to suppliers' reduced term and volume in offers.

Consistent with observations in our January 2022 report, users continue to reassess their exposure to spot markets. Larger users typically use the facilitated spot markets to manage imbalances or take advantage of arbitrage opportunities. In the current market environment, spot markets are, nevertheless, a less economically attractive option for users to diversify their gas portfolio.

Users expressed concerns about high forward prices in facilitated markets with one user reporting $12-16/GJ bids for 2023 Victorian swaps in April. In April 2022, STTM prices were above $15/GJ, which is atypically high for a shoulder period. By mid-May 2022, STTM prices had risen to around $37-$40/GJ, well above LNG netback prices, with DWGM prices of up to $55/GJ also recorded in May.[55] By June, DWGM prices were forecast to rise up to $800/GJ. On 2 June 2022, AEMO invoked administered price caps in Brisbane and Sydney STTMs and Victoria following extremely high prices and the associated RoLR event (see below). Prices were also high in the National Electricity Market (NEM). Users noted that domestic and international conditions in both gas and electricity markets are driving high prices in domestic facilitated markets, making it risky to source gas through these markets.

In our January 2022 interim report, we observed that while participation in facilitated markets can result in lower prices, it can also expose users to significant price risks. We expressed concerns about the ability of small to medium users with high facilitated markets exposure to appropriately balance potential risks and benefits, particularly given their limited bargaining power and supply options. Since January, these risks have been realised and have affected users sourcing gas primarily from facilitated markets.

Causmag International cited high facilitated market prices as the reason for reducing operations, noting it was 'paying over one day what we would normally pay over four days for purchasing gas'.[56]

Recent and unprecedented rises in facilitated market spot prices have, in fact, caused significant disruptions to C&I operations, with some at risk of closing down. Australian textile company, Flickers, is facing the prospect of closing down and plastic producer, Qenos, has noted that its business operations are 'on the line' owing to massive increases in prices on the spot market.[57]

Further impacts of recent price increases led to AEMO suspending Weston Energy Pty Ltd (Weston) from trading in the STTM and DWGM, on 24 May 2022, denoting the market exit of this smaller gas retailer. Weston says unprecedented price increases in April and May 2022 tripled its required working capital, and they were unable to secure additional financing to meet AEMO's prudential requirements.

Weston's primary business model involved providing C&I users with access to gas through buying at and passing through facilitated market spot prices. At the time of their suspension, Weston says it supplied more than 400 C&I gas users in the ECGM. Weston's C&I customers are covered by RoLR arrangements under section 146 of the National Energy Retail Law, where they have a right to supply from another retailer determined by the AER as the RoLR in their particular region. However, there has been significant concern among users about the high prices they are being charged by their RoLR.[58] Shutting their operations after 82 years in business, manufacturer Advance Bricks said they can no longer afford high gas prices which increased 'from $6 to $8/GJ to more than $37/GJ overnight', under the

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55 AER, Wholesale Markets Quarterly Report Q1 2022, May 2022, pp. 22-23.

56 Angela Macdonald-Smith and Mark Ludlow, Soaring gas price pushes manufacturer to brink, Australian Financial Review, 10 May 2022, https://www.afr.com/companies/energy/manufacturing-threat-as-gas-prices-spike-20220510-p5ajxs.

57 Whitson, Rhiana, Australia's gas crisis is worse than you might think. Industries warn thousands could lost their jobs and consumers will pay more, ABC News, 3 June 2022, https://www.abc.net.au/news/2022-06-03/gas-crisis-threatens-manufacturers-jobs-and-rising-prices/101114712.

58 Graham, Jackson, Manufacturers caught in energy crunch are ‘stressed and traumatised’, Sydney Morning Herald, 3 June 2022, https://www.smh.com.au/business/companies/manufacturers-caught-in-energy-crunch-are-stressed-and-traumatised-20220602-p5aqmz.html.

RoLR arrangement with Energy Australia.[59] Another user impacted by the closure of Weston has reported that since this ROLR event, they are paying $44.60/GJ for gas.

Weston's exit reduces competition in the retail market, particularly the choices and options available for securing gas for small and medium C&I users. In our July 2019 interim report we expressed concerns about high retailer margins and concentrated markets as well as the desire to see greater diversity of suppliers in the market.

Reflecting a broader trend, users appear to have been forced to access various sources of information to form pricing expectations and increase engagement in wholesale gas markets in response to tight market conditions. One user noted that engaging with wholesale market arrangements, particularly those involving facilitated markets exposure, requires significantly more complex management capability than that required by retailer contracts. This is particularly difficult for smaller users, even under more stable market conditions. Compared to previous survey results, a higher proportion of survey respondents in this survey are developing an internal view on gas prices. This is reflected in chart 3.3 and highlights the increasing need for the upcoming transparency reforms, which will ensure that short term trades are reported on AEMO's Gas Bulletin Board.

It is concerning, particularly for small-medium users, that other options for sourcing gas (such as through the facilitated markets) are less attractive in the current volatile, high-priced environment. Users are left with fewer cost-effective options to secure gas in an environment of increasing prices for fixed term contracts and growing prevalence of JKM/netback price offers.

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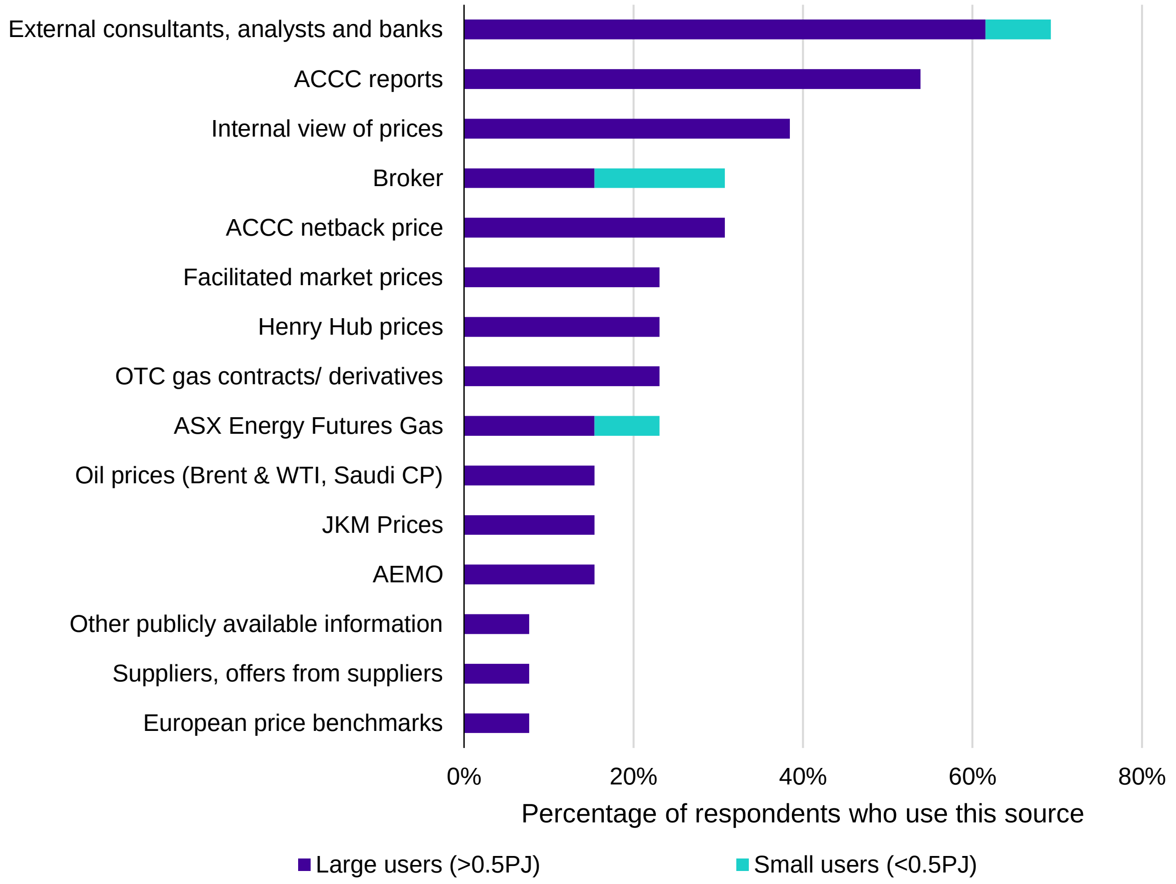
59 Aeria, Gillian, Rising gas prices blamed as Advance Bricks says its oven will go cold after 82 years in Stawell, ABC News, 17 June 2022, https://www.abc.net.au/news/2022-06-17/gas-prices-advance-bricks-energy-crisis-regional-jobs/101161446.

Chart 3.3: Information sources C&I users use to form a view on prices



Source: ACCC Gas inquiry C&I user survey March 2022.

3.4. Alternative fuels and energy efficiency projects

Consistent with previous reports, users continue to consider alternative energy options, with several respondents taking steps to review their processes or replace parts of their annual loads with alternative fuels. Importantly, however, users continue to express concern about the efficacy of alternative fuels and their application to commercial and industrial processes, noting significant costs and uncertainty associated with implementation. This includes concerns about the push for alternative fuels through climate policy and the implications for users' businesses under already difficult market conditions.

One user expressed that 'supply security and cost stability need to be incorporated into any energy transition policy to ensure competitiveness and survival of Australia's manufacturing sector'. Another user noted that 'alternative fuels are only useful if they are economically viable, otherwise the sustainability of their business is called into question'.

3.4.1. Hydrogen usage

As noted in our January 2022 interim report, there are a number of government initiatives to facilitate the development of a hydrogen industry.

Most users do not currently consider hydrogen economically viable, or substitutable for natural gas in their processes. One user has estimated that the price for hydrogen 'from pilot projects is about $35/GJ', approximately 3-4 times the cost of gas (at the time the statement was made).[60] Another user notes that:

> *Hydrogen is unlikely to be technically feasible at scale for a few more decades. As a country we need to manage the pace of transition carefully; policy makers need to do the hard work to appreciate the true complexity and practicality around energy transition before announcing knee-jerk reaction policies that often look at things through a narrow lens.*

Some users have also noted safety, cost, and regulatory uncertainties about blending hydrogen into gas networks and the impact on their processes and end products. One user that does not consider hydrogen economic at current cost notes that if hydrogen is blended in the gas network, they will need to consider how that will affect their processes and plant technology. Another user notes hydrogen 'can assist at the margin, but the technology is not there yet'.

Some users highlight that, due to chemical differences between hydrogen and natural gas, they are not perfect substitutes. Users have also raised potential safety concerns with the implementation of hydrogen into complex manufacturing procedures and implications for their products.

Some users have noted the lack of consultation on legislative schemes, such as the NSW hydrogen certificate scheme, and the associated impact on their business costs. Several users say they were not made aware of the NSW hydrogen certificate scheme until it was substantially progressed and that users were not consulted by the NSW government for their input. A user expressed concerned that the policy has reported that costs will be incurred by the business 'even if they do not use the hydrogen'. Another user similarly expressed that regardless of the use of hydrogen in their processes, the policy would increase their costs, which they are unlikely to be able to pass on to downstream consumers.

Several users have raised concerns regarding their businesses bearing most of the costs if uncoordinated transition policies lead to stranded gas pipeline assets, which require accelerated depreciation. One user also expressed concerns that network assets may be duplicated to accommodate hydrogen, effectively creating two assets for the same purpose. Another user notes that multiple solutions are required for the successful transition of hydrogen.

However, one user expressed optimism and noted they are preparing their processes should hydrogen become economically viable in the future. This includes the ability to use oxygen fuel for steam boilers to power some manufacturing processes.

3.4.2. Biogas from waste and electrification

Some users are substituting their natural gas load with biogas from waste.[61] A user notes biomethane is molecularly equivalent to natural gas and easier to integrate into manufacturing processes. For example, Opal’s Maryvale energy from waste project has the potential to reduce annual demand by approximately 2 PJ.[62] If Opal's and other C&I users' projects progress, this could significantly reduce C&I natural gas demand in the medium to longer term.

Another user undertaking a feasibility study into landfill gas, notes the benefits of being able to co-locate biogas at any plant or biomethane source. However, the user notes that markets

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60 When this statement was made in March 2022, the prices of gas stood at approximately $9/GJ.

61 We note that biogas has been in use by some users for a number of years.

62 Opal Australian Paper, https://opalanz.com/app/uploads/2020/03/N3202-AP-EFW-report-pg48-80-2.pdf.

for waste is outside the user's core business and cited challenges with understanding competition for organic waste. This echoes the sentiment expressed by other users that high gas prices and climate considerations have forced users to develop gas expertise and/or divert resources from their core business operations. It is necessary for businesses to better understand and manage their price risk in gas (and electricity) markets.

Users with processes that can be electrified have sought opportunities to fuel switch into electricity. However, several users noted their inability to use electrification, particularly noting that it would not be an option for processes requiring high heat and pressure, or for those that use gas as a feedstock. User comments include:

> *High heat processes can't currently be electrified and so biogas may present as the only option. This is too expensive, not available and [there are] no regulatory policies in place to support its development.*
>
> *Electrification [is only suitable] for low temperature process heating.*
>
> *Electrification is not an option. 100% of [their] natural gas consumed is to generate steam in large quantities. We have spent considerable time and money into increasing efficiency'. You cannot generate steam from electricity as it is not [economically] viable.*
>
> *[My] main concern is a lack of understanding that there are processes out there that can't be electrified. It is very costly for gas consumers that cannot electrify. Other solutions are needed.*

While electrification provides an attractive alternative to gas for some users, we note electricity prices are currently high in the NEM. In April 2022, average electricity spot prices ranged between $143-233/MWh. There were 345 half-hour intervals where electricity prices exceeded $300/MWh.[63] We note that these high price intervals in the NEM are consistent with high price events we have seen in the facilitated gas markets. Most C&I gas users are also highly electricity intensive. The combined impact of high gas and electricity prices mean such users face high energy costs on both fronts.

Users remain concerned about costs and uncertainty associated with government policy and the subsequent impact on their business operations. We expect more users will consider alternative energy sources as they become more affordable, adequately tailored to their business operations and government policies and transitional arrangements become clearer.

[63] AER, Wholesale Markets Quarterly Report Q1 2022, May 2022.

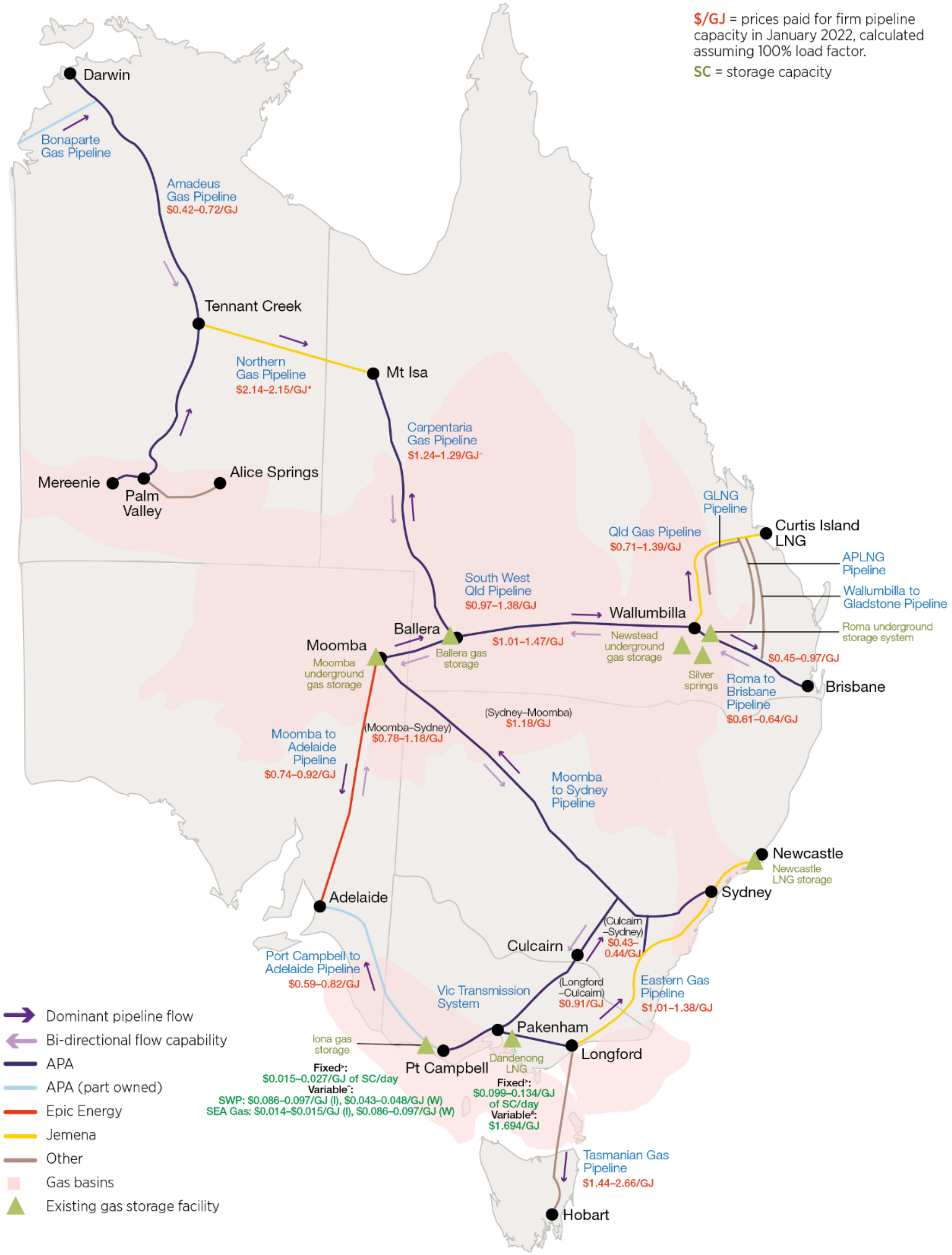
4. Transportation and storage

Key points

- Prices for firm gas transportation services have increased between July 2021 and January 2022, broadly in line with inflation.
- Maximum prices were generally negotiated close to, or at standing price levels, except for services on the Queensland Gas Pipeline and Moomba to Adelaide Pipeline System, where prices consistently sit above the standing price.
- Multi-asset services are becoming increasingly important as more gas from Queensland and potentially the Northern Territory is expected to be required to meet forecast shortfalls in southern states. High prices for these services pose a challenge as they can add a significant amount to the commodity price of gas.
- Recently agreed prices for firm gas transportation have remained within a limited range, supporting our view that monopoly prices first reported on in the ACCC's 2015 inquiry largely continue to be charged.
- New gas transportation agreements and price variations are increasingly being contracted for shorter periods, while longer agreements have become less common over time.
- Changes to the contracting model at the Dandenong LNG storage facility have coincided with decreased contracted capacity, raising system security concerns in the Victorian Transmission System.
- There is sufficient transmission pipeline capacity to allow gas from Queensland to be transported to the southern states to meet the forecast 2023 shortfall.

Figure 4.1 below shows prices for firm transportation services on main gas pipelines and storage facilities as at January 2022.

Figure 4.1: Firm transportation and storage prices as at January 2022



Notes: The transportation and storage prices are based on invoices in January 2022 provided by operators, and exclude GST. Transport and storage prices have been calculated in accordance with the approach described in box 4.1.

* Tariffs include the cost of the nitrogen removal service.

\- While this pipeline is a bi-directional pipeline, the prices reported are for northern haul services only.

\# The variable charge for the Dandenong LNG storage facility reflects the liquefaction cost.

^ The variable charge for the Iona gas storage facility reflects the charge for injection into the storage facility (I) and withdrawal from the storage facility (W).

> While prices have been expressed on a $/GJ of SC/day basis, the ACCC understands that storage services are generally sold under agreements with contract terms of one year or more and not on a day-to-day or short-term basis.

4.1. Introduction

Over the course of the Inquiry the ACCC has reported on a range of matters relating to the supply of, and demand for, gas transport and storage services in the east coast gas market. Using information provided by pipeline operators, we have updated our analysis in this report to include:

- prices payable for firm forward haul services on major transmission pipelines as at January 2022, as well as standing prices published by pipeline operators
- GTAs and contract variations executed between February 2021 and February 2022, as well as negotiations for access to key pipelines over the same period
- prices payable for use of the Dandenong LNG and Iona underground storage facilities
- contracted pipeline capacity to April 2025, and physical flows on key pipelines between July 2021 and April 2022

We will update our analysis of the prices payable for as available and interruptible transportation services, and park and loan services in our next report.

Box 4.1 outlines the approach we have used when reporting pipeline services and prices.

Box 4.1: Pipeline services and approach to reporting prices

There are several different types of pipeline transportation services:

Firm transportation service: A service that allows the transportation of gas on a ‘firm’ basis up to a maximum daily quantity and maximum hourly quantity. It has the highest priority of any transportation service.

As available transportation service: A service that allows the transportation of gas subject to the availability of capacity. This service has a lower priority than a firm transportation service.

Interruptible transportation service: A service that allows the transportation of gas but where the pipeline operator does not have an obligation to guarantee capacity and has the right to curtail the service if the pipeline becomes capacity constrained or higher priority services are required. This service has a lower priority than firm and, where a pipeline has both types of service, as available transportation services.

Park service: A service that allows users to store gas in a pipeline. In practice this involves injecting more gas into a pipeline than what is taken out on a particular day.

Loan service: A service that allows users to “borrow” gas from a pipeline. In practice this involves withdrawing more gas from a pipeline than what is injected on a particular day.

Compression service: A service that increases the pressure of gas to improve the efficiency of transportation. Compression services are provided by compression service facilities.

Approach to reporting prices

The prices reported in this section exclude GST and are based on invoices issued under contracts entered into for a term of one month or longer, and reflect the terms and conditions specified in those contracts.

Any percentage changes in price are stated in nominal, rather than real, terms.

Method used to report pipeline prices

Prices payable for haulage services are reported only where the price applies to transportation across the full length of the pipeline.

The prices for some firm forward haul services are recovered through a capacity charge only (i.e. $/GJ of Maximum Daily Quantity (MDQ)), while others are recovered through a variable charge

($/GJ), or a combination of the two. In the latter two cases, the prices have been converted to a $/GJ of MDQ measure, assuming a 100% load factor (i.e. assuming the shipper uses all the capacity it has contracted). Where the price charged is specified in several tranches, a single rate is calculated on the entire capacity reserved, taking into account the prices payable for each tranche of capacity.

The prices payable for as available and interruptible transportation services, and park and loan services have been included even when the quantity supplied in that month is zero. The prices reported for these services therefore represent the prices that would be paid under the shipper's contracts if the services had been utilised.

The as available and interruptible services category includes APA's 'short-term firm' services, as well as APA's interruptible service, which is only available when a pipeline is fully contracted. APA's day-ahead firm and within-day services have not been included in the analysis of contract prices.

Where relevant, the prices reported for some pipelines include the prices payable for other services required to use that pipeline, such as compression in the case of the South West Queensland Pipeline (SWQP), and the nitrogen removal service in the case of the Northern Gas Pipeline (NGP).

Charges relating to imbalances and overruns are not included in our analysis

Method used to report storage prices

The prices payable for use of the Dandenong LNG and Iona underground storage facilities comprise both a fixed and variable charge. The fixed charge is payable for storage capacity and, although storage services are generally sold under contract terms of a year or more, has been expressed on a dollars per GJ of storage capacity per day basis ($/GJ/day) to enable comparability. The variable charge, on the other hand, is measured on a dollar per GJ basis ($/GJ) and incurred when gas is injected or withdrawn. This charge is used to recover the liquefaction cost at the Dandenong LNG facility and the storage injection and withdrawal charges at the Iona underground storage facility.

Pricing terminology

The term '**maximum price**' is used in this section to refer to the highest price paid by shippers in the relevant period, while the term 'minimum price' is used to refer to the lowest price.

The term '**standing price**' is used to refer to the following prices:

- for pipelines subject to Part 23 of the NGR: the prices the pipeline operator is required to publish as part of the standing terms for each service offered by the pipeline
- for pipelines that are subject to light regulation under the NGR: the prices that are required to be published
- for pipelines subject to full regulation under the NGR: the reference tariffs that are required to be published.

Comparability of prices

The prices payable by shippers for use of pipelines and storage facilities will reflect, among other things, the terms and conditions specified in their transportation and storage agreements and when the prices were agreed. The actual prices payable by shippers to use one of these facilities may therefore differ as a result of differences in capacity commitments (including withdrawal and injection rates for storage), service flexibility (e.g. hourly flexibility, load factor), contract length, the time at which the prices were agreed or reviewed (including whether a contract is a foundation agreement or will fund an expansion) and whether services are provided across a number of assets.

4.2. Prices for gas transport services reflect lack of competitive constraints

4.2.1. Background

Gas transmission pipelines move gas from production fields in the Northern Territory, Queensland, South Australia and Victoria to major demand centres in cities and regional areas in the east coast. While the cost of transporting gas on a single pipeline is relatively small when compared to gas commodity prices, gas is generally not transported on a single pipeline. Rather, it can involve the transportation of gas across the interconnected set of pipelines in the east coast, the cost of which can quickly add up.

This report considers the costs of transporting gas across these interconnected pipelines. The minimum, maximum and standing prices paid for firm haulage services in January 2022, and how these changed between July 2021 and January 2022, are outlined in the section below.

Generally, gas pipelines exhibit natural monopoly characteristics. These characteristics mean that paying for access to an existing pipeline is often more economically efficient than constructing a new pipeline. They can also accord the service provider with substantial market power. The exercise of market power can have a detrimental effect on economic efficiency, the costs of which are ultimately borne by consumers.

In the ACCC's 2015 inquiry we observed that while pipeline operators had been responding well to the changes underway in the market, a large number of them had been engaging in monopoly pricing.[64] This was giving rise to higher delivered gas prices and having an adverse effect on economic efficiency and consumers. In the intervening period, we have seen no real change in the behaviour of pipeline operators, with transportation prices largely remaining steady over this period.

To address this market failure, we have recommended a number of changes to the regulatory framework that applies to pipelines, many of which have recently been endorsed by Energy Ministers and are expected to be implemented later this year.[65]

4.2.2. Prices for firm forward haul services have increased in line with inflation

Table 4.1 outlines the minimum, maximum and standing prices paid for firm haulage services in January 2022, and how these changed between July 2021 and January 2022, with key changes bolded.

Price changes shown in Table 4.1 generally reflect relatively higher inflation, with a 3.5% increase in the CPI for the 12 months to 31 December 2021. Orange shading in the table indicates prices that have nominally increased since July 2021, while blue shading shows prices that have decreased or remained unchanged in the same period.

64 As noted in the ACCC’s 2015 Inquiry, monopoly pricing is not a contravention of the Competition and Consumer Act 2010 (Cth) (CCA). It is legitimate and expected commercial behaviour. In a market economy where the profit motive drives private enterprise, it is expected that firms that do not face effective competition, or a threat of such competition, will engage in such behaviour. Monopoly pricing can, nevertheless, have a detrimental effect on economic efficiency and consumers.

65 For an overview of these reforms, see ACCC, Gas Inquiry 2017-25 interim report, January 2022, pp. 154-56.

Table 4.1: Firm Haulage Service Prices as at January 2022

Pipeline	Owner	Price (as at January 2022) Min	Max	Standing Price	Price change between July 2021 and January 2022 (%) Min	Max	Standing Price
AGP	**APA**	0.418	0.721	0.340	-0.82%	2.10%	0.00%
CGP	**APA**	1.242	1.288	1.288	0.00%	2.10%	2.11%
RBP eastern haul	**APA**	0.448	0.966	0.767	1.93%	2.55%	2.10%
RBP western haul	**APA**	0.613	0.642	0.767	-1.74%	**-8.50%**	2.10%
SWQP western haul	**APA**	1.007	1.469	1.393	0.00%	**2.88%**	2.11%
SWQP eastern haul	**APA**	0.969	1.377	1.505	**2.39%**	**3.01%**	2.10%
MSP (Culcairn to Sydney)	**APA**	0.430	0.443	0.441	2.12%	2.11%	2.11%
MSP (Moomba to Sydney)	**APA**	0.778	1.182	1.182	2.11%	1.75%	2.11%
MAPS southern haul	**Epic Energy**	0.741	0.924	0.843	2.24%	3.01%	3.01%
NGP	**Jemena**	2.136	2.154	2.412	**3.70%**	**-7.60%**	3.50%
QGP (to Gladstone)	**Jemena**	0.710	1.387	1.078	0.00%	**4.17%**	3.01%
EGP	**Jemena**	1.007	1.378	1.378	2.71%	3.50%	3.50%
PCA	**SEA Gas**	0.587	0.817	0.949	2.11%	3.01%	3.02%
TGP	**TGP**	1.444	2.660	2.551	3.50%	0.00%	**29.39%**

Note: Pipeline operators escalate their standing prices at the beginning of the calendar year. In addition to this, APA adjusts its prices quarterly in April, July and October. Minimum and maximum prices change frequently based on GTAs that have either commenced, expired or been varied during the relevant period.

Source: ACCC analysis of data supplied by pipeline operators, standing price data from pipeline operator websites.

Key changes observed over the 6 months to January 2022

Prices for gas transportation have generally increased in line with inflation over the period.

In some cases the percentage increase in the maximum and/or the minimum price shown in the table may differ from the change in the relevant standing price.

In APA's case, this is due to the way in which escalation formulas are applied in GTAs compared to the escalation of standing prices. For some contracts, APA adjusts the prices annually, so the relevant CPI adjustment will differ between a small number of GTAs and standing prices.

For other pipelines, the difference between the increase in prices and the relevant standing price is due to either:

- the inclusion of fixed, non-recurring, charges in either the July or January invoices, or
- a contract being negotiated.

The minimum price paid for transport on the Northern Gas Pipeline (NGP) increased more than the standing price (3.70% vs. 3.50%). However, this is due to different rebates being applied in the July 2021 and January 2022 invoices, which affect the final price paid and in turn the half-yearly variation.

The maximum price paid for services on the Queensland Gas Pipeline (QGP) rose 4.17% in the period as a result of a shipper entering a new GTA which included a 1.12% increase in respect to July 2021 prices, further increased by a 3.01% yearly escalation from 1 January 2022.

For eastern haul services on the South West Queensland Pipeline (SWQP), the increases in both the minimum price (2.39%) and maximum price (3.01%) were both greater than the increase in the standing price (2.10%) over the same period. This was primarily due to the timing of escalations for CPI, but also affected by the application of fixed and seasonal charges.

Similarly, the 2.88% increase in the maximum price for the SWQP western haul, is the result of applying the yearly escalation as per the GTA, however the increase was partly mitigated by the removal of seasonal charges that were in the July 2021 invoice for that shipper.

Because of market developments and the particulars of the services acquired in the period, there has been a decrease in some prices paid compared to July 2021.

The maximum price on the Northern Gas Pipeline (NGP) in January 2022 was 7.60% lower compared to July 2021. This is due to the shipper paying the maximum price in July 2021 not acquiring the service in January 2022.

The maximum price on the Roma Brisbane Pipeline (RBP) western haul decreased 8.50% in the six months to January 2022. This change occurred because the shipper previously paying the maximum price entered into a new contract on more favourable terms.

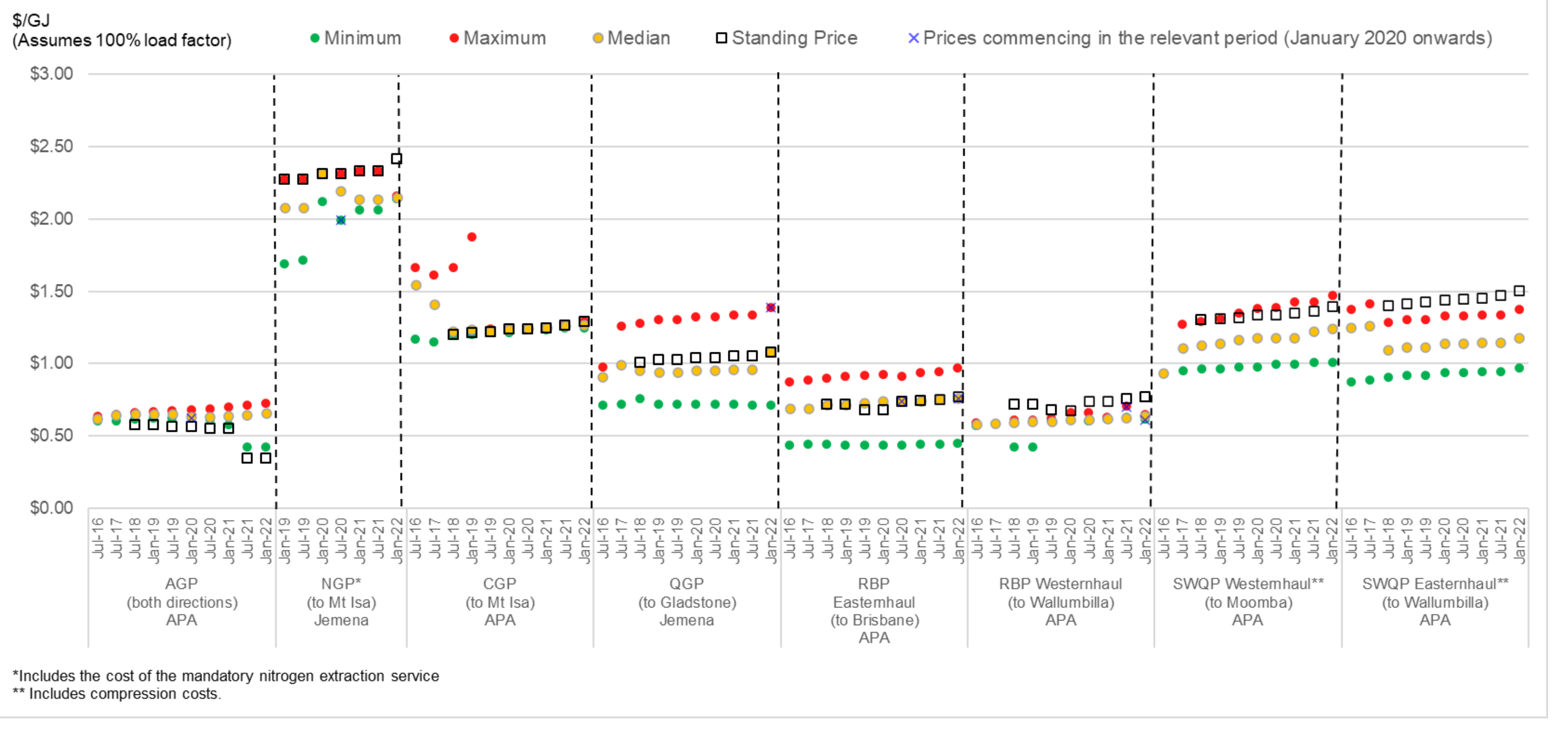
The standing price on the TGP has increased significantly by 29.39% since July 2021. This change was made in February and retrospectively applied to reflect the price for new capacity from January 2022.

Trends in minimum, maximum and standing prices over time

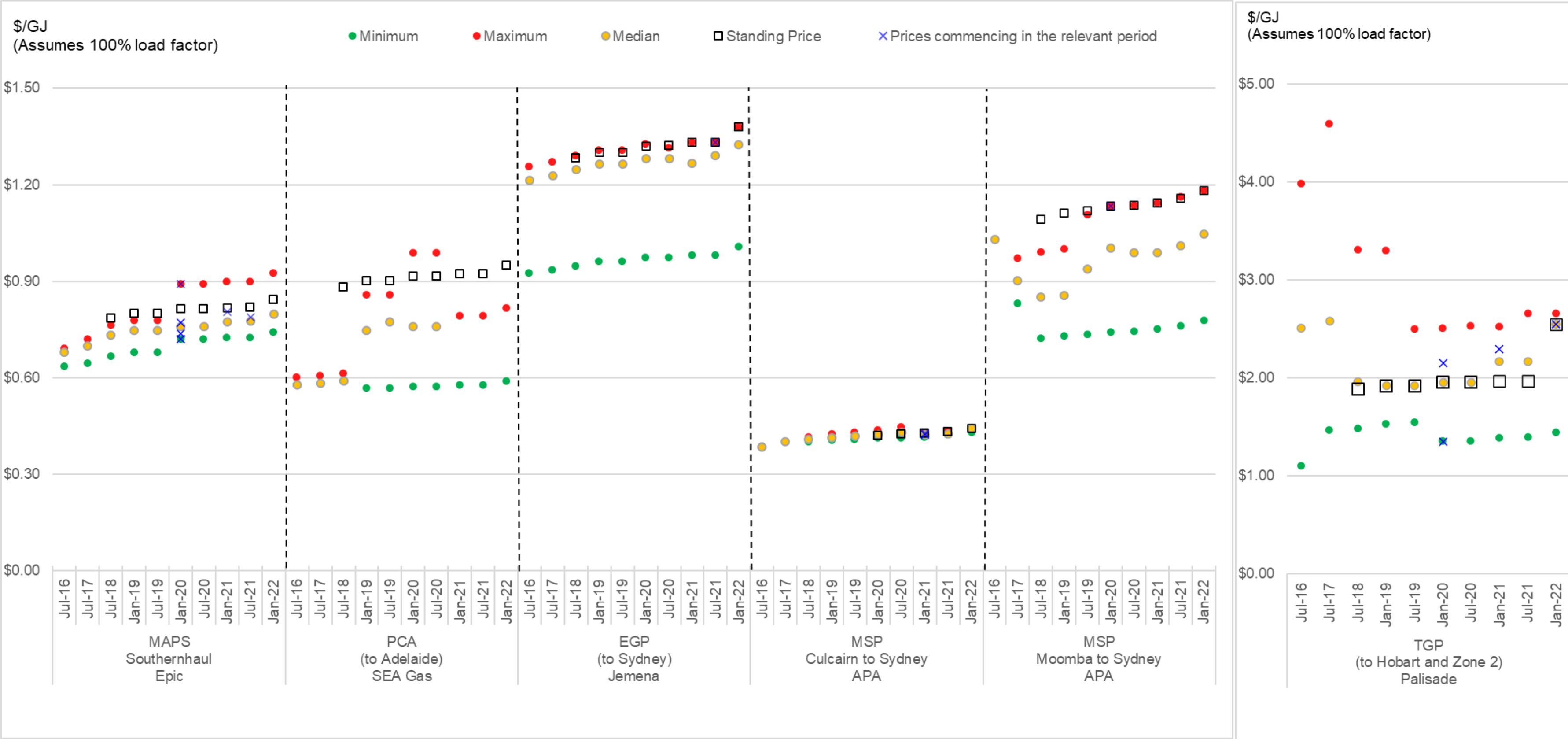
Chart 4.1 below shows the minimum and maximum prices paid by shippers for firm forward haul services between July 2016 and January 2022 on key pipelines in Queensland and the Northern Territory (Northern Pipelines) and the southern states (Southern Pipelines). The chart also shows prices payable for new contracts and variations entered into since July 2021.

Chart 4.1: Firm forward haul transportation prices ($/GJ, nominal), July 2016 to January 2022

Northern Pipelines



Southern Pipelines



Note: the number of prices commencing shown in this chart (as 'x's) for July 2021 and January 2022 is not directly comparable with the number of new GTAs/variations identified in section 4.4 below for a number of reasons. Some services linked to new GTAs or variations are excluded as they relate to part-haul services, back haul or zero MDQ.

Chart 4.1 above shows nominal prices for transport services have generally followed an upward trend over time, approximately in line with inflation.

New prices ('Xs' on the chart) for the QGP and TGP align with, or are close to, maximum prices in the period, while prices for services on the RBP have been negotiated at or below the standing price.

Standing prices have generally increased with a CPI-based escalation, showing a more pronounced increase in January 2022, due to the relatively higher inflation in recent months.

Maximum prices are generally close to or align with standing prices, except for the QGP and MAPS, where some shippers have been paying prices well above the standing price. This is also the case for the RBP eastern haul, although a new GTA adopted a price at the standing price level. This was also the case for the TGP until this period, in which the standing price has increased significantly to come closer to the maximum price and to prices paid by shippers on the pipeline.

The standing price for the AGP fell by almost 38% in the last reporting period due to a new approved access regime, in place from 2021 to 2026. The AGP is subject to full regulation, and the standing price reflects the reference tariff approved by the AER (as reported in the ACCC's January 2022 interim report).

4.2.3. Offers for multi-asset transportation lie above minimum prices for equivalent individual services

Table 4.2 shows indicative firm forward haul prices for transporting gas to and from key locations in the east coast gas market over multiple pipelines. The indicative standing prices in the table are calculated by adding up the standing prices for firm forward haul services for each individual asset relevant to the selected routes. The same process is used to calculate indicative minimum prices and indicative maximum prices.[66]

Consistent with the adjustment in prices shown in Table 4.1 above, comparative prices for most multi-asset services have increased in nominal terms from July 2021 to January 2022 (orange shading). The effect of price reductions on the NGP and RBP western haul can also be seen (blue shading). Unshaded figures did not change over this period.

[66] Note that the indicative firm forward haul costs presented in the table are based on invoices issued under contracts entered into for a term of one month or longer. Other contract terms and conditions may also differ from multi-asset firm service contracts.

Table 4.2: Multi Asset Indicative Firm Haulage Prices ($/GJ as at January 2022)

To:	From:	Tennant Creek	Mt Isa	Brisbane	Wallumbilla	Moomba	Adelaide	Wilton (Sydney)	Culcairn (Vic)	Port Campbell	Longford
Mt Isa	Min $/GJ	2.14		2.86	2.25	1.73	2.57	2.91	2.91	3.16	3.92
	Max $/GJ	2.15		3.37	2.76	1.98	2.82	3.16	3.16	3.41	4.17
	Standing Prices $/GJ	2.41		3.29	2.68	2.04	2.88	3.22	3.22	3.47	4.23
Brisbane	Min $/GJ	4.79	2.66		0.45	1.42	2.26	2.60	2.60	2.85	3.61
	Max $/GJ	5.78	3.65		0.97	2.34	3.19	3.53	3.53	4.00	4.90
	Standing Prices $/GJ	5.97	3.84		0.77	2.27	3.11	3.45	3.45	4.06	4.83
Wallumbilla	Min $/GJ	4.35	**2.21**	0.61		0.97	1.81	2.15	2.15	2.40	3.16
	Max $/GJ	4.82	**2.66**	0.64		1.38	2.22	2.56	2.56	3.04	3.94
	Standing Prices $/GJ	5.20	**2.79**	0.77		1.50	2.35	2.69	2.69	3.30	4.07
Moomba	Min $/GJ	3.58	1.44	1.62	1.01		0.84	1.18	1.18	1.43	2.19
	Max $/GJ	3.74	1.58	2.11	1.47		0.84	1.18	1.18	1.66	2.56
	Standing Prices $/GJ	3.98	1.57	2.16	1.39		0.84	1.18	1.18	1.79	2.56
Adelaide	Min $/GJ	4.32	2.18	2.36	1.75	0.74		1.92	1.92	0.59	2.93

	Max $/GJ	4.66	2.51	3.04	2.39	0.92		2.11	2.11	0.82	3.48
	Standing Prices $/GJ	4.82	2.41	3.00	2.24	0.84		2.02	2.02	0.95	3.40
Wilton (Sydney)	Min $/GJ	4.36	**2.22**	2.40	1.79	0.78	1.62		0.43	1.34	1.01
	Max $/GJ	4.92	**2.76**	3.29	2.65	1.18	2.02		0.44	1.36	1.38
	Standing Prices $/GJ	5.16	**2.75**	3.34	2.58	1.18	2.02		0.44	1.35	1.38
Culcairn (Vic)	Min $/GJ	4.76	2.63	2.80	**2.19**	1.18	2.02	0.44		0.91	0.91
	Max $/GJ	4.92	2.76	3.29	**2.65**	1.18	2.02	0.44		0.91	0.91
	Standing Prices $/GJ	5.16	2.75	3.34	**2.58**	1.18	2.02	0.44		0.91	0.91
Hobart	Min $/GJ										1.44
	Max $/GJ										2.66
	Standing Prices $/GJ										2.55
Curtis Island LNG	Min $/GJ	5.06	2.92	1.32	0.71	1.68	2.52	2.86	2.86	3.11	3.87
	Max $/GJ	6.21	4.05	2.03	1.39	2.76	3.61	3.95	3.95	4.42	5.33
	Standing Prices $/GJ	6.28	3.87	1.85	1.08	2.58	3.43	3.77	3.77	4.37	5.14

Source: ACCC analysis of data supplied by pipeline operators, standing price data from pipeline operator websites.

Notes: Standing prices have been used in cases where there are no minimum or maximum prices. We have assumed that prices for transportation on the SWQP from Moomba to Ballera are 0.5 times the SWQP eastern haul tariff; and from Ballera to Moomba are 0.2 times the SWQP western haul tariff. This is based on information provided by APA. For example, prices from Mt Isa to Adelaide have been calculated as: CGP + 0.2 x SWQP western haul + MAPS southern haul.

The prices in the table can be compared to APA's advertised prices for multi-asset services. APA offers multi-asset firm services between key receipt and delivery points in the Northern Territory, Queensland and NSW.

APA's advertised prices for multi-asset firm services are:

- Mt Isa to Sydney for $2.06/GJ/day, compared to a total of $2.75/GJ/day when paying individual standing prices.
- Wallumbilla to Culcairn for $2.06/GJ/day, compared to a total of $2.58/GJ/day when paying individual standing prices.
- Mt Isa to Wallumbilla for $1.85/GJ/Day, compared to a total of $2.79/GJ/day when paying individual standing prices.[67]

When compared to the indicative prices that are bolded in table 4.2, we can see that shippers seeking to transport gas on those selected routes are able to secure lower prices than the indicative standing prices by using APA's multi-asset services. However, these multi-asset service prices are still considerably more than the indicative minimum prices across these routes.

More generally, gas transportation can add a significant cost for users located far away from gas production facilities. For example, the indicative standing price for transporting gas from the Northern Territory (Tennant Creek) to Sydney, Melbourne (Culcairn) or Adelaide ranges from $4.82-$5.16/GJ. Indicative standing prices for transportation from Wallumbilla to these destinations, although not as high, still range from $2.24 to $2.58/GJ which can add a significant amount to commodity gas prices.

As more gas from Queensland and possibly the Northern Territory is expected to be required to meet forecast shortfalls in southern states, the impact of persistently high transportation costs will continue to grow.

4.2.4. Recently agreed prices have remained within a limited range

In the ACCC's 2015 inquiry we found that pipeline operators were engaging in monopoly pricing. We have examined whether there has been any material change in pricing since that Inquiry. To do this, we have compared the prices that have been agreed under contracts entered at different times. To remove the effects of inflation, we have converted all the prices to real $2022 prices.

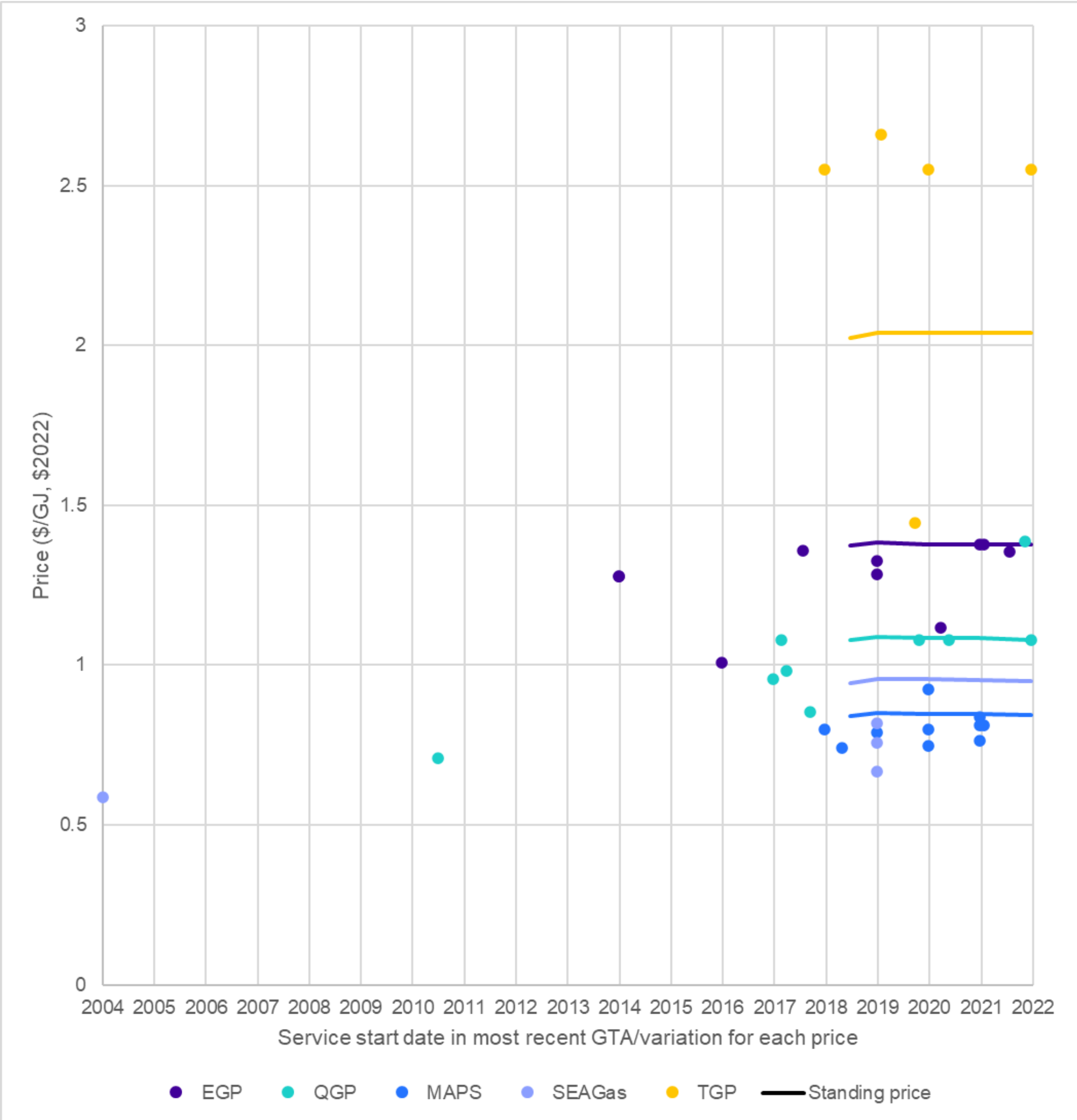
Prices paid in January 2022 for firm forward haul services are set out in GTAs that have been entered into over a long period of time. Prices agreed to more recently are therefore more reflective of current market conditions facing shippers.

Chart 4.2 shows the prices paid by shippers for firm forward haul services in January 2022, and the service commencement date of the GTA or GTA variation where the price was agreed or confirmed. The standing price for each pipeline over time has also been added as a point of comparison and is represented as a line. For some services, the most recent GTA or variation signed carried over pricing from an earlier agreement or variation.

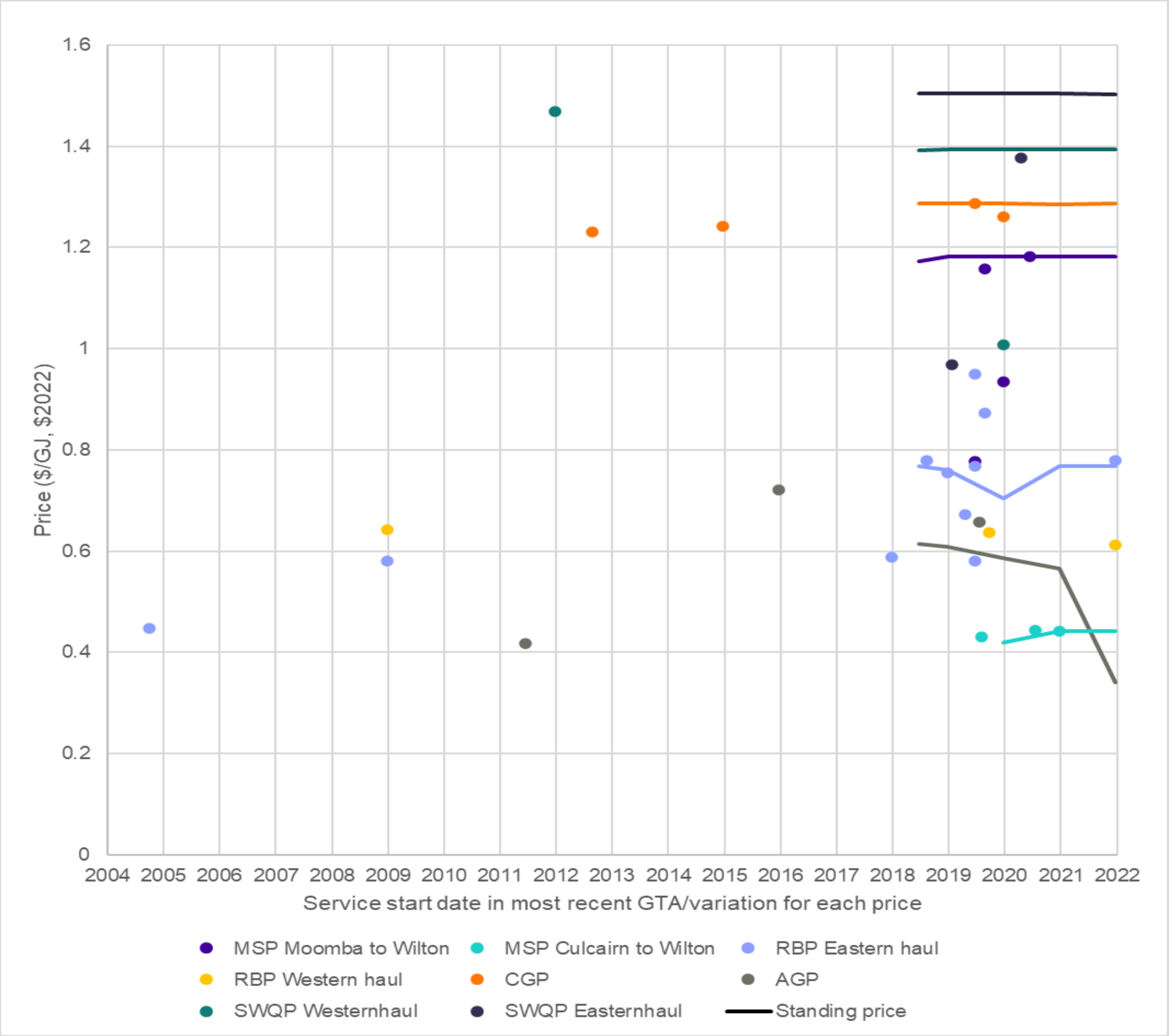
[67] APA group, Multi-asset transport, accessed 29 April 2022.

Chart 4.2: Prices paid for firm forward haul services in January 2022, by date price was agreed

Non-APA pipelines



APA pipelines



Source: ACCC analysis of data supplied by pipeline operators.

Note: RBP Western and Eastern haul share the same standing price represented by the violet line.

The charts above show that for both APA and non-APA pipelines, prices have generally remained within a limited range, with the majority either steady or with a slight upwards trend. This supports our view that monopoly prices first reported on in the ACCC's 2015 inquiry largely continue to be charged. Current reforms to improve transparency of pricing and the overall regulatory framework applying to gas pipelines will assist in addressing some of the information asymmetry that exists between pipeline operators and shippers.[68]

The RBP eastern haul, AGP, TGP and MSP (Moomba to Wilton) show the greatest dispersion of prices among shippers. It is worth noting that the RBP and AGP are the only pipelines subject to full regulation by the AER under the NGR. Despite the AER setting reference tariffs on these pipelines there is seemingly more variability in agreed prices.

Consistent with the analysis in section 4.2.2, agreed prices are generally close to or at standing prices. This is not the case for TGP however, where prices paid by shippers are consistently above standing prices.

[68] For an overview of these reforms, see ACCC, Gas Inquiry 2017-25 interim report, January 2022, pp. 154-56.

4.3. New agreements are increasingly contracted for shorter periods

This section considers negotiations, variations and new agreements in the 12 month period between 27 February 2021 and 21 February 2022. During this period, there were a total of 244 negotiations between pipeline operators and customers. This data covers both negotiations for both firm forward haulage and as available services such as day ahead and interruptible haulage.

It should be noted that negotiations are not only for new contracts but also negotiations to vary existing contracts such as extensions of terms, changes in delivery and receipt points, contracted capacity, new services and new connections or other capital works. Out of the total 244 negotiations in 2021, 66 related to new contracts while the remaining 178 related to variations of existing contracts.

Negotiations most often lead to a contract being executed when they have a duration between 60-180 days. Long-running negotiations that have not resulted in contracts being executed can often involve discussion of complex legal and technical requirements and in some cases investigation of further capital works.

Similarly, negotiations may conclude without an agreement being reached, or may still be ongoing at the end of the relevant period. The number of new contracts and variations has remained relatively consistent between the current and previous reporting periods, as shown by Table 4.3 below.

Table 4.3: New agreements entered into, 2020 and 2021

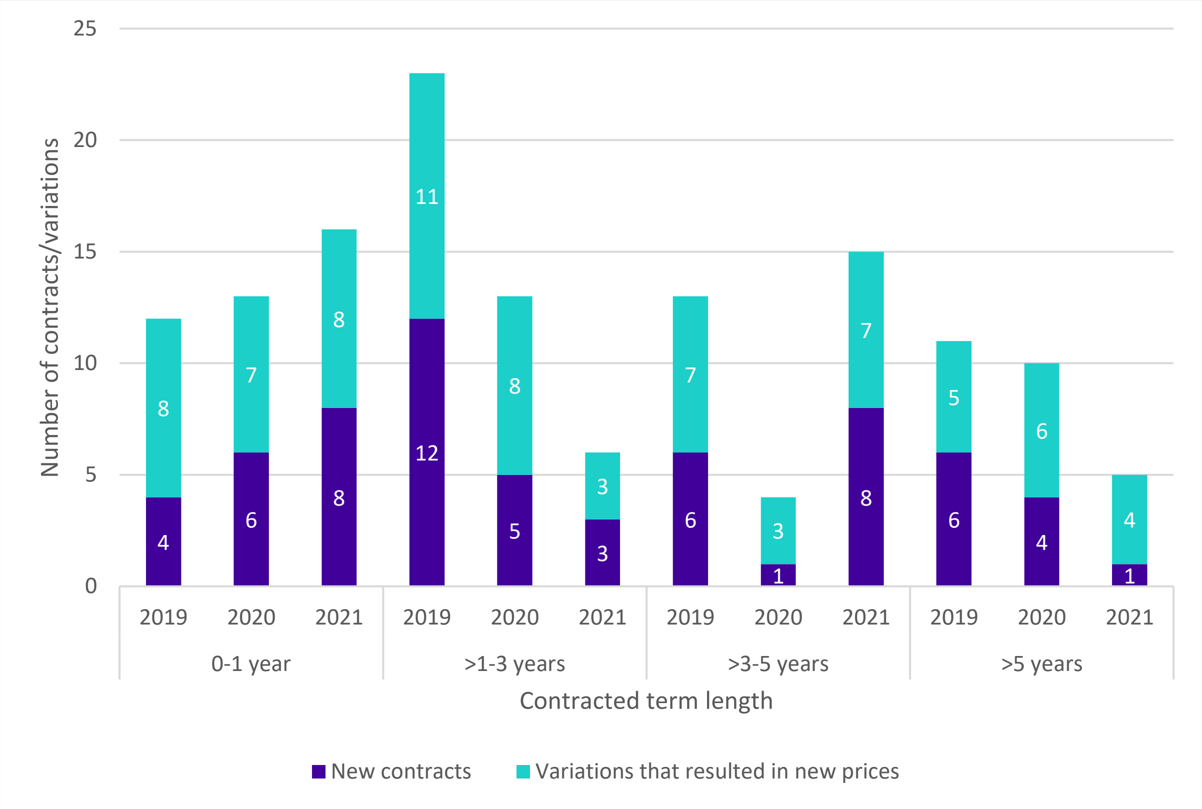
	Variations	New contracts
2020	101	28
2021	114	34

Source: ACCC analysis of data supplied by pipeline operators.

Note: '2020' refers to 24 February 2020 to 26 February 2021. '2021' refers to 27 February 2021 to 21 February 2022.

Chart 4.3 shows the number of new GTAs and price variations for firm forward haul services by contract term length, noting that this also includes mixed service contracts that include firm forward haul. These contract term lengths are divided into four different buckets as shown. This chart does not represent all of the GTAs that are currently in force and only shows those executed between 15 March 2019 and 21 February 2022. Over time shorter contracting periods are becoming increasingly common for new agreements, with 0-1 year agreements growing steadily over time. Inversely, longer terms agreements lasting more than 5 years have consistently decreased over time.

Chart 4.3: Contract terms for new GTAs and price variations relating to firm forward haul services over time executed between 15 March 2019 and 21 February 2022



Source: ACCC analysis of data supplied by pipeline operators.

Note: '2019' refers to 15 March 2019 to 23 February 2020. '2020' refers to 24 February 2020 to 26 February 2021. '2021' refers to 27 February 2021 to 21 February 2022.

4.4. Pipeline capacity appears sufficient to help meet projected shortfalls in southern states

This section considers haul capacity for major gas transmission pipelines throughout the east coast gas market.

As discussed in chapter 1, forecast demand is expected to exceed forecast supply by 54 PJ in the southern states in 2023. This represents a significant deterioration in conditions relative to equivalent forecasts for 2022, when demand was forecast to exceed supply by 6 PJ. The forecast supply-demand balance means that the southern states will be reliant on, among other sources, additional gas being directed south from the Cooper Basin and Queensland. This additional southern haul will require sufficient pipeline capacity to be available in 2023.

We analysed transmission pipeline capacities in order to determine if there is sufficient capacity for this additional southern haul. In order to undertake this analysis we considered a scenario where we assumed a net 54 PJ will be required to be transported on the SWQP (to Moomba) in addition to a projected 47 PJ supply from the Cooper Basin. Overall, this scenario involved transporting a total of 101 PJ (54+47) from Moomba on the MSP or MAPS.

There appears to be sufficient transmission pipeline capacity overall to transport an additional 54 PJ on the SWQP to Moomba, and 101 PJ on the MSP and MAPS, in 2023. In some limited circumstances, pipeline usage may approach or reach capacity on a particular day. However, this has generally not been the case, as illustrated in the sections below. The ability to store gas at Moomba, Iona and, to some extent, Dandenong (as described in section 4.5) means that overall pipeline capacity is not a constraint on meeting southern state shortfalls in 2023 by transporting gas from Queensland.

4.4.1. Pipeline capacity contracted

The charts below provide a comparison of the May 2022 pipeline capacity outlook (columns), for the period from May 2022 to April 2025, with the outlook presented in our January 2022 interim report.[69]

Since this report, there have been changes to available capacity, as reported by operators, and our current outlook for each pipeline's degree of contractual congestion, shown in charts 4.4 and 4.5, reflects the current state of the market. Uncontracted capacity is expected to change as contracts are executed and pipeline capacity is increased.

The current pipeline capacity outlook in charts 4.4 and 4.5 indicate that only a few assets are fully contracted, or close to fully contracted, for the forecast period. Many pipelines have significant uncontracted capacity available.

For example, the PCA from Port Campbell to Adelaide, and the MSP (northern and southern haul) have a reasonable amount of uncontracted capacity available. The MSP appears to have available capacity even during the winter months of 2022. The MAPS (northern haul), EGP, CGP, and NGP also have a reasonable amount of uncontracted capacity available.

The southern haul capacity of the MAPS from Moomba to Adelaide is fully contracted until December 2022, after which there is a decrease in contracted capacity throughout 2023 to 2024.

There are some facilities where the capacity has been fully contracted, or close to fully contracted, in the near term or over our whole period of analysis. This includes the AGP from Palm Valley to Channel Island LP and the SWQP for Moomba Compression which is often fully contracted. The AGP from Palm Valley to Channel Island LP pipeline, which moves gas to Darwin, Alice Springs and regional centres primarily for power generation, is following a similar trend in contracted capacity to our previous analysis for the January 2022 report.

There has also been a significant increase on the amount of capacity contracted on the TGP from Longford to Hobart since the last report, and the pipeline is now almost fully contracted.

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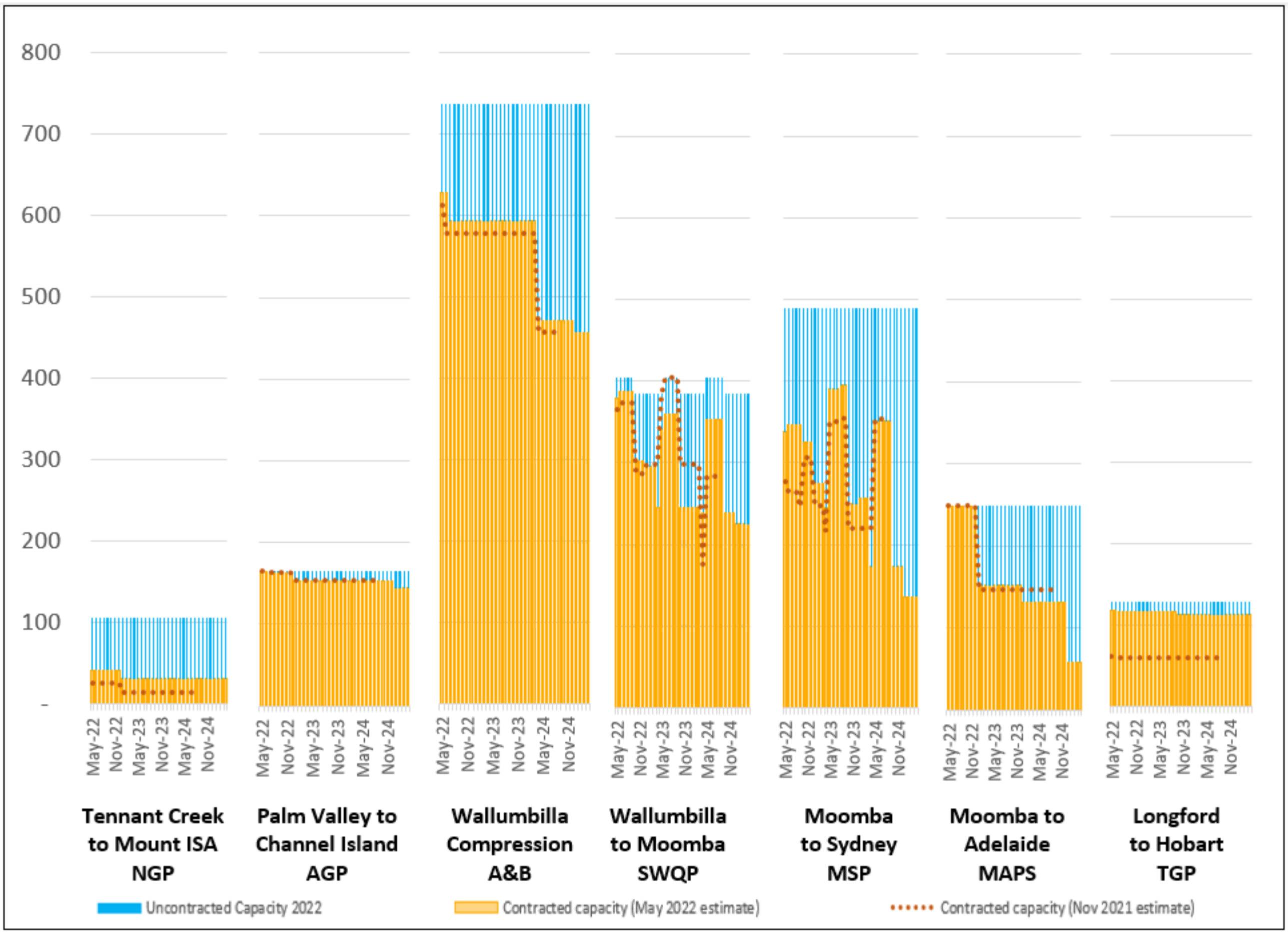
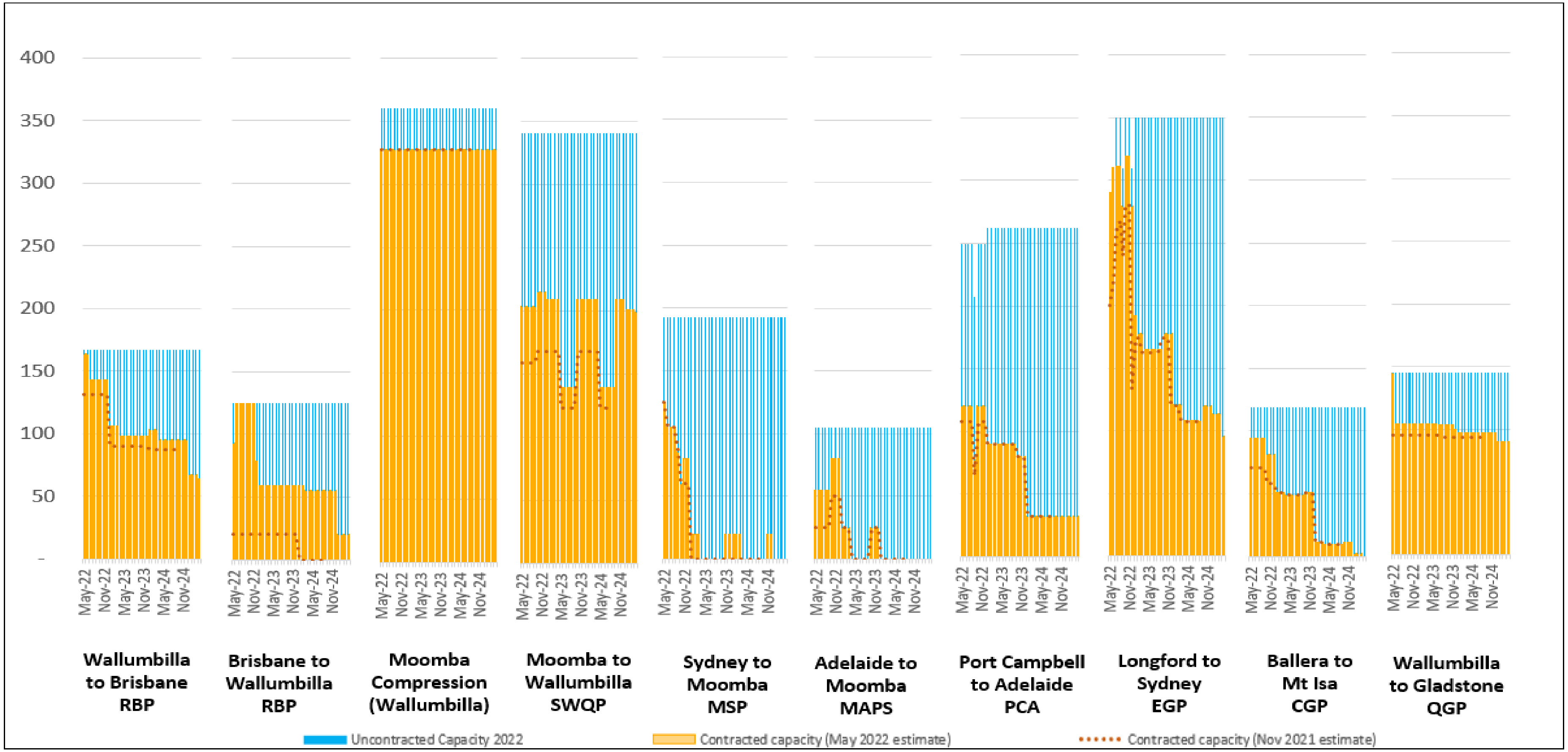
69 Our estimates of capacity contracted in the chart were derived from two different sets of data, which involved subtracting AEMO's gas bulletin board October 2021 and April 2022 uncontracted capacity data from the nameplate rating. This methodology for estimating the contracted capacity does not take into account other factors such as changes to nameplate capacity, and may produce contracted capacity estimates that are larger than the actual. As the uncontracted capacity input data is not altered in this analysis, our estimates of capacity contracted can appear larger in previous periods, as is the case for the SWQP to Moomba pipeline, if the uncontracted capacity increases rather than decreases. For pipelines subject to Part 23 of the NGR, the contracted capacity has been calculated using the 36-month service availability information reported on each pipeline operator's website and the nameplate rating reported on the Natural Gas Services Bulletin Board (accessed April 2022). For other pipelines (i.e. the Roma to Brisbane Pipeline, the Amadeus Gas Pipeline, the Northern Gas Pipeline and the Carpentaria Gas Pipeline), the contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (accessed April 2022).

Chart 4.4: Facilities that can transport gas to southern states contracted capacity (TJ/day, 2021 and 2022 outlook), May 2022 to April 2025



Sources: For pipelines subject to Part 23 of the NGR, the contracted capacity has been calculated using the 36-month service availability information reported on each pipeline operator's website and the nameplate rating reported on the Natural Gas Services Bulletin Board (accessed April 2022). For other pipelines, the contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (accessed April 2022).

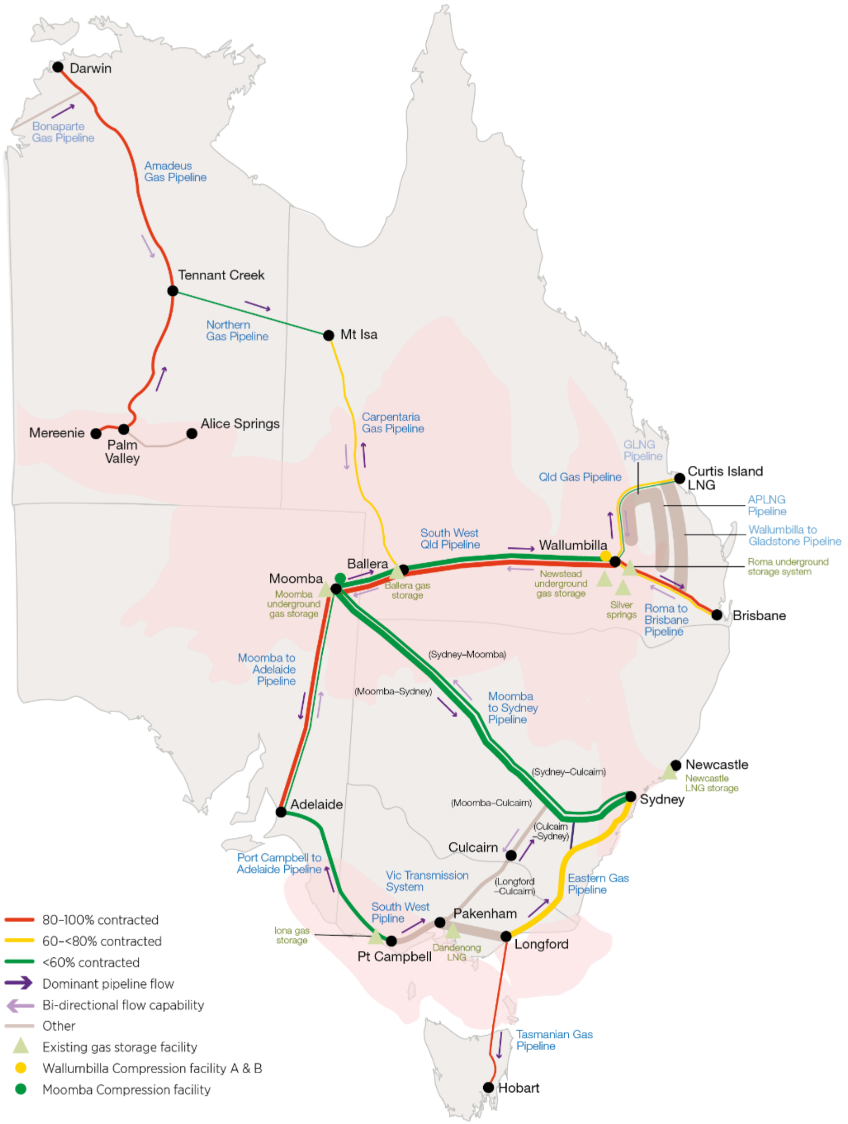
Chart 4.5: Other facilities contracted capacity (TJ/day, 2021 and 2022 outlook), May 2022 to April 2025



Sources: For pipelines subject to Part 23 of the NGR, the contracted capacity has been calculated using the 36-month service availability information reported on each pipeline operator's website and the nameplate rating reported on the Natural Gas Services Bulletin Board (accessed April 2022). For other pipelines, the contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (accessed April 2022).

Figure 4.2 below shows the amount of firm capacity contracted for the 12 months from May 2022 to April 2023.

Figure 4.2: Pipeline capacity contracted between 1 May 2022 and 30 April 2023



Sources: For pipelines subject to Part 23 of the NGR, the contracted capacity has been calculated using the 36-month service availability information reported on each pipeline operator’s website and the nameplate rating reported on the Natural Gas Services Bulletin Board (accessed April 2022). For other pipelines, the contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (accessed April 2022).

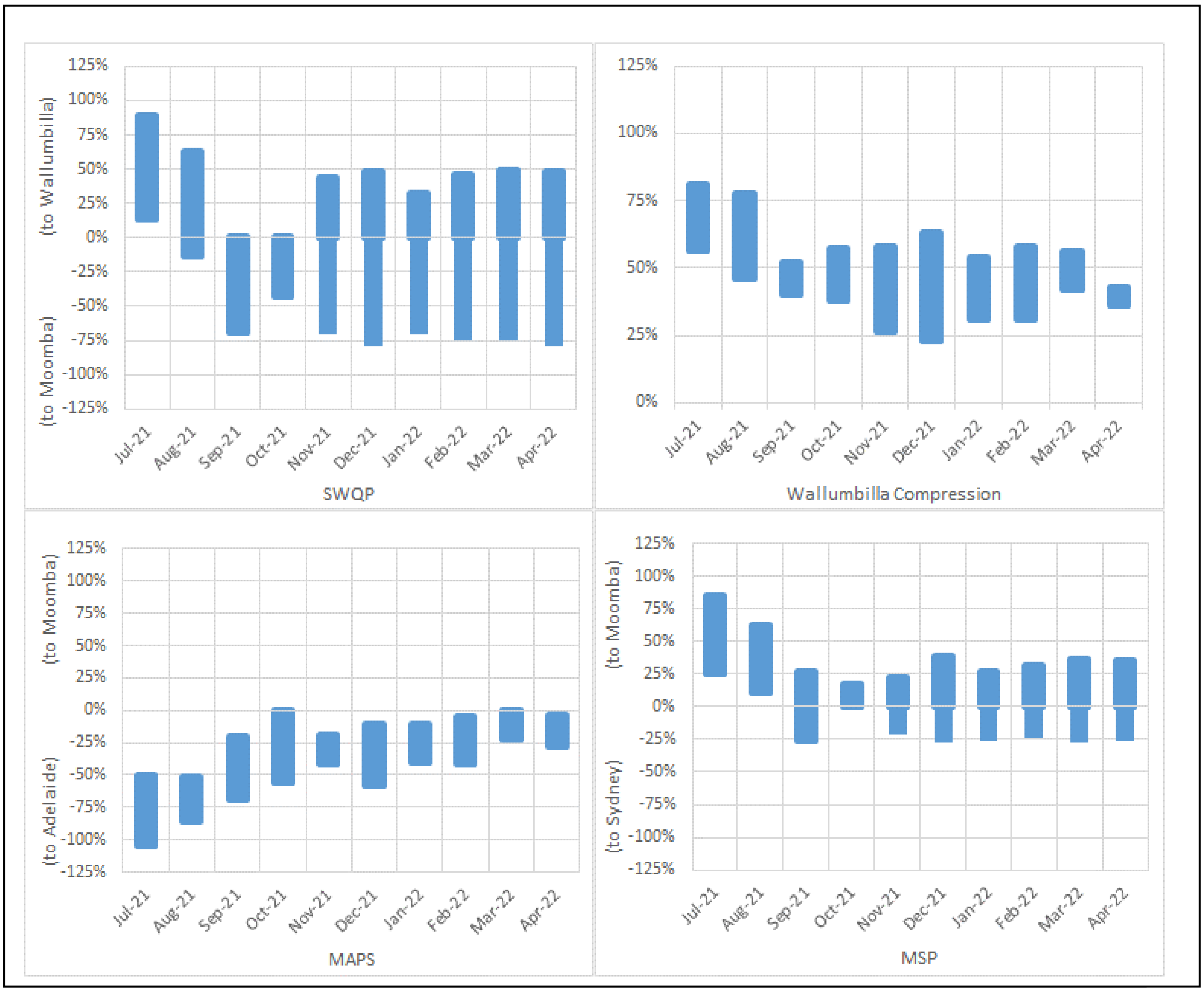
Notes: Percentage of contracted pipeline capacity indicated by red, yellow and green lines. It reflects the average contracted capacity of the pipeline over the twelve months between May 2022 and April 2023. Pipeline nameplate capacity is indicated by the width of the pipeline, with the widest representing the greatest nameplate capacity.

4.4.2. Pipeline capacity usage

Shippers that do not have firm capacity may experience difficulties transporting gas through other means like the Day Ahead Auction (DAA) for contracted but unnominated capacity, or as available or interruptible services. We have examined the use of these facilities over the last year to better understand their capacity constraints.

Chart 4.6 depicts the maximum daily percentage of the pipeline nameplate capacity used each month for transporting gas on certain bi-directional pipelines. The chart sources information from pipeline operators on the actual gas transported on pipelines across the east coast between July 2021 and April 2022.

Chart 4.6: Range of daily nameplate capacity (%) used each month, July 2021 to April 2022



Source: Pipeline connection flow and nameplate rating information reported to the Natural Gas Services Bulletin Board. The monthly utilisation measure represents the daily minimum and maximum physical gas flows in each month for the period 1 July 2021 to 20 April 2022, expressed as a percentage of the facility's nameplate capacity.

As chart 4.6 shows, there were winter days in July 2021 where the MAPS exceeded 100%, and the SWQP exceeded 90%. As reported previously, in those instances on the MAPS where utilisation has exceeded 100%, Epic has been able to increase physical capacity in the short term to meet peak demand.

While many pipelines do not exceed their theoretical physical capacity over the course of a year, they do come close to reaching their maximum capacity during the winter months. This is the case most notably for the MSP and SWQP in July 2021. We also note that the Wallumbilla compression facility did not experience any physical constraints during this period.

4.5. Storage facilities continue to be crucial in managing supply and demand risks

The Dandenong LNG and Iona underground storage facilities (owned by APA and Lochard Energy, respectively) are the only facilities that currently provide storage services to third parties in the east coast gas market, however they provide different services.

The Dandenong LNG storage facility is used to store small volumes of gas to be injected quickly into the Victorian Transmission System (VTS). This gas is usually used to address short-term peaks and system security issues in Victoria. A large part of the cost of storing gas at Dandenong LNG is the liquefaction cost to turn the gas into LNG. In contrast, the Iona underground storage facility is a now-depleted conventional gas field that has been adapted to allow gas to be pumped back down into the reservoir and stored. The Iona facility is ordinarily used to store large volumes of gas during summer months, which is withdrawn in winter to meet seasonal demand for gas.

The need for storage services in southern states is likely to grow further given the forecast shortfall in supply detailed in chapter 1.

As the Iona and Dandenong storage facilities are used by customers for the differing purposes outlined above, they do not compete directly with each other, nor do they face competition from other operators for similar services. This lack of competition affords each storage facility considerable market power when setting prices for their services.

These differences are reflected in each facility's price structure.

4.5.1. There has been little change in prices and contracting at Iona

Lochard charges injection and withdrawal charges at Iona, as well as a fixed storage charge, but the injection and withdrawal charges make up a relatively small part of the overall cost of storage. Lochard's charges at Iona are set out in table 4.4 below. The variable charge for the facility reflects the charge for injection into the storage facility from either the South West Pipeline or the SEA Gas Pipeline, or withdrawal from the storage facility to either of those pipelines.

Table 4.4: Storage prices at Iona ($/GJ), January 2021 to January 2022

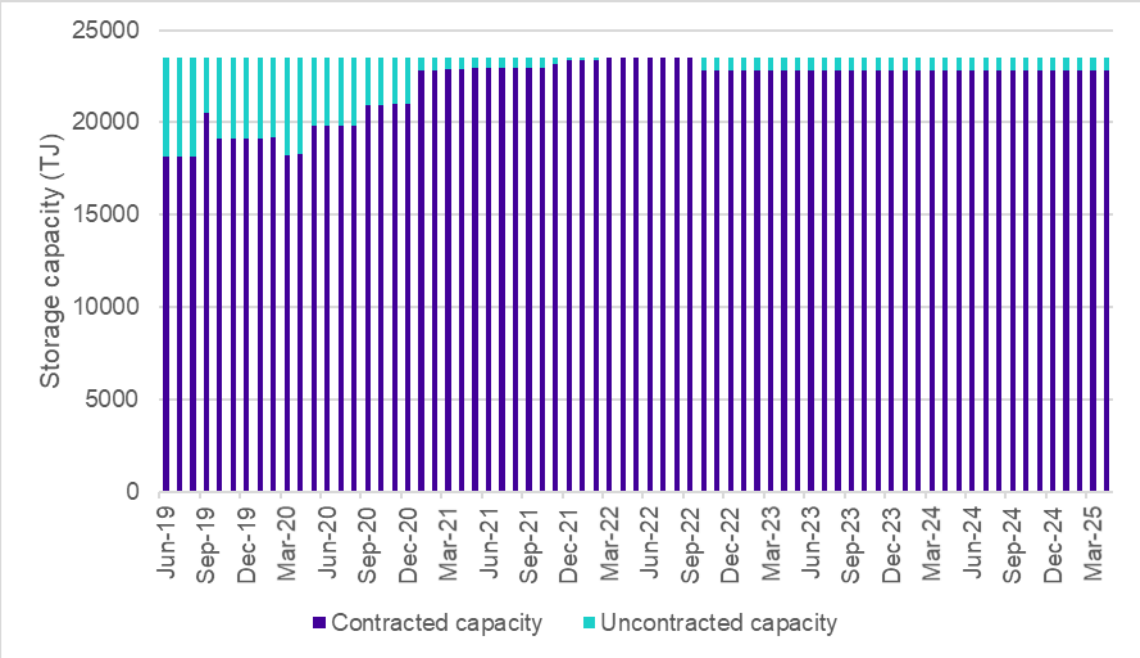
		January 2021 ($/GJ)	July 2021 ($/GJ)	January 2022 ($/GJ)
Fixed (per day)		0.015-0.026	0.015-0.026	0.015-0.027
Variable	Injection from SWP	0.084-0.094	0.084-0.094	0.086-0.097
	Withdrawal to SWP	0.042-0.047	0.042-0.047	0.043-0.048
Variable	Injection from SEA Gas	0.014	0.014	0.014-0.015
	Withdrawal to SEA Gas	0.083-0.093	0.084-0.094	0.086-0.097

Source: ACCC analysis of data supplied by Lochard

Prices at Iona gas storage facility have not changed significantly since July 2021. The amount of firm storage reservoir capacity contracted by users at Iona has increased slightly from 22.8PJ to 23.4PJ across the same 10 users from January 2021 to January 2022. This compares to an overall nameplate capacity of 23.5PJ.

Contracted capacity at the Iona facility has been close to or at 100% since the beginning of 2021. Furthermore, Iona is forecast to be contracted at near capacity from May 2022 to April 2025, reflecting the greater level of price stability of the facility, as shown in chart 4.7.

Chart 4.7: Contracted capacity at Iona over time



Source: Publicly available data from AEMO's Gas Bulletin Board

4.5.2. Higher prices at Dandenong LNG have persisted and the facility remains underutilised

Reflecting the increased cost of converting gas into LNG and storing it, prices at Dandenong LNG are significantly higher on a per GJ basis than at Iona.

APA restructured the contracting model for all new gas storage agreements at the Dandenong LNG storage facility signed since December 2020. Under the previous model, users contracted storage capacity rights which would in turn be used to determine (on a pro rata basis) access to vaporisation services (the service required to withdraw gas from storage). Under the new model, users contract a required amount of firm vaporisation directly, and are provided with a multiple of this amount as an associated storage capacity right.

APA maintains that this new contracting model benefits users, by providing more certainty around their ability to vaporise gas. As previously reported, the restructure has caused effective storage prices at the Dandenong facility to increase significantly. These new higher effective storage prices have persisted in January 2022.

Storage prices at Dandenong have again been calculated by dividing the total amount paid by the user for firm vaporisation, by the total amount of storage provided to that user. Using this approach, storage prices have remained the same since July 2021 costing users between $0.099/GJ/day and $0.134/GJ/day in January 2022. This represents a price increase for all users of between 8% and 46% since January 2021 and 44% and 46% since July 2020.

Table 4.5 shows the prices paid for storage at the Dandenong LNG facility from January 2021 to January 2022.

Table 4.5: Storage prices at Dandenong LNG storage ($/GJ), January 2021 to January 2022

	January 2021 ($/GJ)	July 2021 ($/GJ)	January 2022 ($/GJ)
Storage (per day)	0.092	0.099-0.134	0.099-0.134
Liquefication	1.3014-1.744	1.694	1.694

Source: ACCC analysis of data supplied by APA

Note: Storage prices at Dandenong from July 2021 have been calculated by dividing the total amount paid by the user for firm vaporisation, by the total amount of storage provided to that user.

The Dandenong LNG storage facility has seen no change in prices since July 2021, however this follows the implementation of a new contracting model in December 2020 which saw an increase in the effective cost of storage of up to 46% for some customers (these are considered further in the next section).

The impact of the change in contracting model can also be considered by looking at the effective cost of vaporisation. Before the change, in July 2020, the average effective cost of vaporisation capacity among shippers was $0.34/GJ/day. The effective cost of vaporisation capacity can be calculated by dividing the total amount paid by the user for storage (under the previous contracting model) by the amount of vaporisation capacity available to that user. In January 2022 the average cost of vaporisation has increased to $0.53/GJ/day representing an average increase of 53%.

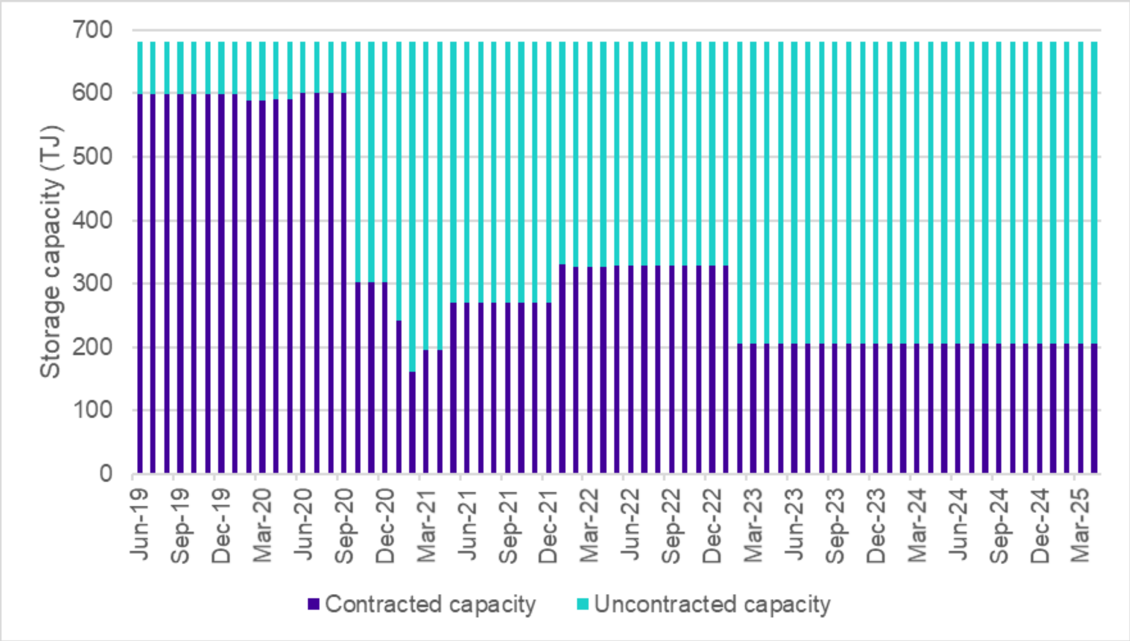
The change in contracting model at Dandenong LNG has coincided with a significant decrease in contracted capacity at the Dandenong storage facility, from 517TJ across 8 shippers in July 2019 to 188TJ across 6 shippers in July 2021 and remained at this amount in January 2022.[70] Nearly all remaining users have contracted for a significantly decreased volume of storage. The lower capacity contracted capacity figures, and actual storage levels at Dandenong have also raised system security concerns.

Chart 4.8 below displays the levels of contracted and uncontracted capacity at Dandenong from June 2019 to April 2025 using publicly available information from AEMO's Gas Bulletin Board.

In contrast to Iona, the Dandenong facility has historically been contracted at near capacity, until around late 2020 whereafter contracted capacity begins to decline steadily coinciding with the facility's change in contracting model. Dandenong has a significant amount of uncontracted capacity forecasted from May 2022.

[70] This figure does not include the 60TJ contracted by AEMO in January 2022, explained in section 4.5.3.

Chart 4.8: Contracted capacity Dandenong LNG over time



Source: Publicly available data from AEMO's Gas Bulletin Board

As shown above, the change in contracting model has coincided with a steep decline in contracted capacity at the facility by users.

The only contracts executed between APA and shippers for storage services at the Dandenong facility in the period between 27 February 2021 and 21 February 2022 were those that came from offers and requests which sought to extend existing contract rates or rates equivalent to current contracts into the new contracting model. There were no variations to existing contracts which altered the price payable by the shipper. In the few instances that shippers attempted to negotiate lower prices for their contracted volumes and term lengths their requests were rejected by APA.

APA's ability to change its contracting model and reject shippers' requests to negotiate more favourable terms underscores the significant market power that they have in respect of the Dandenong LNG facility.

In our January 2022 report, we recommended that consideration be given to implementing a third party access regime for storage, particularly given how critical storage is expected to be going forward with AEMO projecting peak day supply shortfalls.[71]

4.5.3. AEMO has intervened at the Dandenong LNG storage facility following a threat to system security

In its 2021 Victorian Gas Planning Report AEMO identified a threat to system security for the Victorian Transmission System during winter 2021. This threat was a result of low contract levels at the Dandenong storage facility. AEMO found that only 80TJ of market contracted capacity would be available at Dandenong for the winter of 2021 onwards. AEMO's forecast of gas required to be held in the facility in an emergency curtailment situation to support the stabilisation of critical system pressures is a minimum of 140 TJ.[72]

71 ACCC, Gas Inquiry 2017-2025 interim report, January 2022, pg. 86.

72 AEMO, 2021 Victorian Gas Planning Report, March 2021.

In response to this, AEMO contracted 60TJ of LNG reserve (storage capacity) on 20 January 2022 to counteract the threat to system security in the Victorian Transmission System. This 60TJ is on top of the 188 TJ of market contracted capacity held by shippers noted above.

The National Gas Law and Rules allow AEMO to contract an LNG reserve, the costs of which can be recovered through AEMO's gas fees. Currently, AEMO can inject its LNG reserve into the system within the context of an intervention measure under Rule 343. AEMO is likely to only inject gas from its LNG reserve in the case of an emergency curtailment situation. Modelling provided by AEMO's 2022 VGPR update supports continued intervention by AEMO at the Dandenong storage facility.[73]

Historically the Dandenong LNG storage facility had been critical to security in the Victorian Transmission System, acting as the only alternate gas supply to Longford. Prior to 2010 AEMO held the right to an LNG reserve of 3,000 tonnes (~165TJ) or approximately a quarter of the Dandenong LNG facility's capacity as a hedge against an emergency curtailment situation. In 2010 the Australian Energy Market Commission made a rule determination to remove AEMO's right to 3,000 tonnes of storage capacity for an LNG reserve. This was in response to reduced reliance on LNG for system security.

In the lead up to 2010 new gas supply sources for the Victorian Transmission System emerged including the NSW-Vic interconnect and the South West Pipeline, which were estimated to provide 460-500 TJ/day of alternative supply from Longford and Dandenong.

The intent of the 2010 Rule Determination was to release the 3,000 tonnes of storage reserved for AEMO, to improve and promote efficient capital investment in the Dandenong LNG facility and provide APA with greater flexibility over operation of the facility.

Some elements of the original mechanisms were retained, including the potential for AEMO to re-establish and LNG reserve and the intervention powers allowing AEMO to inject from an LNG reserve. Following the rule change, market participants have maintained Dandenong LNG storage levels at close to the maximum capacity of 680TJ, meaning that the facility could be relied on for security without AEMO having to actively manage an LNG reserve.

The tight supply and demand conditions as evidenced in Chapter 1 mean that alternative supply sources can be relied on less and that LNG storage at Dandenong is once again becoming critical for system security. However, given the lower levels of contracted capacity at Dandenong, AEMO will not be able to rely solely on contracted gas at the facility for system security as it used to.

AEMO is currently seeking feedback methods for managing security with the Dandenong facility. This includes the option of taking an active position with regards to managing an LNG reserve at Dandenong for system security, since it is no longer able to rely on contracting levels at the facility.

[73] AEMO, 2022 Victorian Gas Planning Report Update, March 2022, pp. 62-3.

5. Review of upstream competition and timeliness of supply

Key points

- Recent events across the east coast gas and electricity markets have shown the consequences of having insufficient gas supply to meet domestic demand and ineffective upstream competition.
- Supply conditions are expected to deteriorate further in 2023, with a shortfall of 56 PJ now expected. This is expected to occur against the backdrop of a highly concentrated upstream market, with competition posing little constraint on the behaviour of producers.
- Ensuring there is sufficient supply in the east coast gas market both immediately, and over the longer term, is critically dependent on measures to improve competition and encourage the timely supply of gas.
- Stage 1 of the ACCC's review focused on structural factors that may be affecting competition and/or the timeliness of supply. This was completed in January 2022 and found:
  - Greater diversity and more timely supply could be encouraged through changes to government processes for releasing acreage and approving, monitoring and enforcing compliance with work programs.
  - Upstream competition and the timeliness of supply could be significantly improved by reducing the infrastructure, regulatory and capital barriers faced by producers, including by introducing a third party access regime for upstream infrastructure.
- Stage 2 of our review focuses on concentration and the behavioural factors that may be affecting competition and/or the timeliness of supply. Our key findings are:
  - The upstream market is highly concentrated and dominated by the three LNG exporters and their associates. In 2021 they were able to exert their influence over close to 90% of the 2P reserves in the east coast, through a combination of direct interests in 2P reserves, JVs and exclusivity provisions in GSAs through which they buy gas from other producers. This highlights the effective control that the LNG exporters have over the supply and development of gas in the east coast, as well as competition in the domestic market.
  - JVs can adversely affect competition if JV participants do not put in place and adhere to robust ring-fencing arrangements that prevent the sharing of commercially sensitive information with other projects in which JV participants have an interest. A JV participant can also have the incentive and opportunity to exploit their position in a JV to delay the development of gas by the JV if it improves the participant's competitive position in other projects.
  - Joint marketing by participants in incorporated and unincorporated JVs is more prevalent than we expected, with the LNG exporters and some other producers engaging in joint marketing in the domestic market without authorisation. This is resulting in a material reduction in the number of producers competing to supply gas into the domestic market, reducing competition.
  - Exclusivity provisions in GSAs entered into between domestic producers (as sellers) and LNG exporters (as buyers) are restricting the ability of domestic producers to compete to supply gas into the domestic market. These provisions can also reduce the incentive that domestic producers have to develop gas over time and result in development decisions being based on the requirements of the LNG exporters, rather than the domestic market.
  - Mergers and acquisitions of other producers, tenements or interests in JVs by larger producers, can result in a reduction in producers competing to supply gas into the market and slow the progress of gas development.
- Together with the high degree of concentration in this part of the market, JV, joint marketing and exclusivity arrangements are contributing to the lack of effective upstream competition in the east coast. They may also increase the risk of coordinated conduct and increase the market power of the LNG exporters. This is concerning given the supply conditions expected in the east coast and the reliance that will be placed on the LNG exporters.
- Entering into these types of arrangements without authorisation risks breaking the restrictive trade

practices provisions in Part IV of the CCA. While in the past producers may have considered that these arrangements would not substantially lessen competition, in a concentrated and tight market the effect on competition can be heightened.

- We will continue to review some of these arrangements and, where appropriate, consider enforcement action.

5.1. Introduction

In early 2021, the ACCC commenced a review of the structural and behavioural factors that may be impeding competition in the upstream segment[74] of the east coast gas market and/or the timeliness with which gas is brought to market.

This review is being carried out in response to concerns raised throughout the Inquiry about the degree of concentration in this segment of the market and the potential for producers to engage in activities that could limit competition, or otherwise prevent gas from being supplied to market in a timely manner.[75] The need for the review has been reinforced by the tightening market conditions and other aspects of the Inquiry that point to the limited degree of competition in this part of the market, as highlighted by:

- the pricing behaviour that we have observed over the course of the Inquiry and our review of suppliers' pricing strategies, which indicates competition is posing little constraint on producers' pricing decisions[76]
- C&I user surveys we have undertaken, which have consistently raised concerns about the lack of effective upstream competition and the adverse effect this has on selling practices, gas prices and the non-price terms and conditions in GSAs (see chapter 3).

The review has been carried out in two stages. The findings of Stage 1, which focused on the structural factors that may be affecting competition and/or the timeliness of supply, were set out in our January 2022 interim report and are summarised in box 5.1.

In this report we set out the findings of Stage 2, which has focused on:

- the degree of concentration in the upstream segment of the east coast gas market
- the behavioural factors that may be contributing to the concentrated nature of this part of the market and impeding competition and/or the timeliness of supply.

In undertaking this stage of the review, we have had regard to the restrictive trade practices provisions in Part IV of the CCA (see box 5.2 for the most relevant provisions). The ACCC has not formed a view on whether any of the conduct described in this chapter breaches these provisions.

We have also had regard to:

- the feedback provided by stakeholders in response to the issues paper we published in September 2021 on the structural and behavioural factors that may be affecting supply and/or upstream competition[77]

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74 This term is used throughout the report to refer to that part of the market involved in exploration, appraisal and production.

75 See for example the discussion set out in ACCC, Gas inquiry 2017-2025 interim report, January 2020, pp. 39-43 and ACCC, Gas inquiry 2017-2025 interim report, January 2021, pp. 31-32 and Appendix A

76 See ACCC, Gas inquiry 2017-2025 interim report, January 2021, p. 8 and ACCC, Gas inquiry 2017-2025 interim report, July 2021, p. 11

77 In total, we received 18 responses to the issues paper, two of which were confidential. The public submissions were received from user associations (the Energy Users Association of Australia (EUAA) and the Major Energy Users (MEU) group), producers (APLNG, Arrow, CNOOC, ConocoPhillips, Cooper Energy, ExxonMobil, GLNG, Origin, Santos, Shell, Tokyo Gas, Vintage Energy and WestSide) and Australian Petroleum Production & Exploration Association (APPEA).

- information provided in response to the compulsory information notices that we issued to a sample of small and large producers and held meetings with a number of producers.

Based on our review of this information, we have identified a number of behavioural factors that may be impeding upstream competition and the timeliness with which gas is brought to market. These factors, which are discussed in further detail in this chapter, primarily relate to:

- the JV arrangements employed by producers, which while enabling producers to overcome the barriers associated with developing gas, can facilitate coordinated conduct across projects if effective ring-fencing arrangements are not put in place and can also be used to slow the development of new sources of supply
- the joint marketing of gas by JV participants (either incorporated or unincorporated), which reduces the number of producers competing to sell gas into the domestic market
- the exclusivity provisions that may be included in GSAs between producers, which can limit the ability of the selling producer to compete to sell gas in the domestic market and can also affect the timeliness with which gas is brought to market
- merger and acquisition activities undertaken by larger producers, which can result in a reduction in competition and slow the development of new sources of supply.

In addition to these behavioural factors, concerns have been raised throughout the Inquiry about some producers' decisions about when to bring gas to market. We are still examining this factor and intend to report on our findings in the next interim report.

Box 5.1: Stage 1 findings and recommendations

In Stage 1 of the review, we found that there are a number of structural factors impeding upstream competition and the timeliness with which gas is brought to market. We also found that:

- greater diversity and more timely supply could be encouraged through changes to the processes used by governments when releasing acreage and when approving, monitoring and enforcing compliance with work programs
- upstream competition and the timeliness of supply could be significantly improved by reducing the infrastructure, regulatory and capital barriers faced by producers.

We therefore recommended that state, territory and Commonwealth governments:

- encourage greater diversity and more timely supply by:
  - not granting acreage to producers that already control significant acreage unless they can be satisfied it won’t affect the producer’s development of existing or new acreage
  - following Queensland’s lead by considering diversity of suppliers and the efficiency with which gas can be brought to market, alongside the technical and financial capabilities of tenderers
  - actively encouraging gas to be brought to market in a timely manner (e.g. by specifying shorter timeframes for exploration and appraisal, refusing to renew exploration/retention permits for a second term, and taking action for non-compliance with work programs)
- take steps to reduce the infrastructure and regulatory barriers faced by producers by:
  - implementing a light handed commercially-oriented third party access regime for upstream infrastructure through the National Gas Law and National Gas Rules
  - removing duplication in regulatory approvals processes, addressing limitations and uncertainties in these processes and helping producers to navigate the approvals process

Box 5.2: Relevant provisions of Part IV of the CCA

The provisions in Part IV of the CCA that are of most relevance to this review are:

- Section 45, which prohibits a corporation from making or giving effect to a contract, arrangement or understanding containing a provision, or engaging in a concerted practice, having the purpose, effect or likely effect of substantially lessening competition in a market.
- Sections 45AF, 45AG, 45AJ and 45AK, which prohibit the making and/or giving effect to a contract, arrangement or understanding that includes a cartel provision. Cartel conduct is defined in section 45AD of the CCA and prohibits conduct known as price fixing, market sharing, bid rigging and output restriction. [78]
- Section 46, which prohibits a firm with a substantial degree of market power from engaging in conduct that has the purpose, effect or likely effect of substantially lessening competition in a market.
- Section 47, which prohibits various forms of exclusive dealing if it has the purpose, effect or likely effect of substantially lessening competition in a market.
- Section 50, which prohibits acquisitions of shares or assets if the acquisition would have the effect, or be likely to have the effect, of substantially lessening of competition in a market.

Exemptions or statutory protection against legal action under these parts of the CCA can be obtained, on application, if the ACCC is satisfied that the relevant legal test is met and grants authorisation.

5.2. Competition between producers is not effective

In 2020 we expressed concerns about the prices that were being offered by a number of producers in the east coast gas market and decided to undertake a review of producers' pricing strategies. The findings of this review were published in our January and July 2021 interim reports.[79] In short, we found that competition was not effective and was placing limited constraint on the prices offered by producers in the east coast market.[80] Our review of producers' internal documents also revealed limited references to their competitors' pricing behaviour, at least in ways that demonstrated competition was constraining their behaviour.[81]

The findings of the pricing strategies review are consistent with the observations that C&I users have made throughout the Inquiry, including through the most recent C&I user survey (see chapter 3). That is, that competition between producers is ineffective and has had an adverse effect on the ability of C&I users to procure gas on competitive terms. C&I users have also expressed concerns about the ‘take it or leave it’ approach[82] employed by a large number of producers when making offers[83] and claimed that: [84]

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78 These provisions are subject to the application of the JV exemption under ss. 45AO and 45AP of the CCA, which can be satisfied where:

(a) the cartel provision is for the purposes of the joint venture and reasonably necessary for undertaking the joint venture

(b) the joint venture is for the production, supply or acquisition of goods or services, and

(c) the joint venture does not have the purpose of substantially lessening competition.

This exemption does not apply under s. 45 of the CCA.

79 ACCC, Gas Inquiry 2017–2025 interim report, July 2021, chapter 3 and ACCC, Gas Inquiry 2017–2025 interim report, chapter 6.

80 ACCC, Gas Inquiry 2017–2025 interim report, July 2021, section 3.2 and ACCC, Gas Inquiry 2017–2025 interim report, January 2021, section 6.3.

81 ACCC, Gas Inquiry 2017–2025 interim report, July 2021, p. 11.

82 Some C&I users have, for example, stated that they have been provided very little time to accept offers and, in some cases, had offers withdrawn from producers. Others have noted that there was no effective negotiation around prices or non-price terms and conditions, with C&I users effectively being ‘price takers’.

83 See for example, ACCC, Gas inquiry 2017-2020 interim report, July 2019, Chapter 3, ACCC, Gas inquiry 2017-2020 interim report, December 2018, Chapter 3, ACCC, Gas inquiry 2017-2020 interim report, July 2018, Chapter 3, and ACCC, Gas inquiry 2017-2020 interim report, September 2017, Chapter 3,

- prices offered by producers are in excess of what would prevail in a competitive market
- there has been a significant deterioration in the service flexibility and other non-price terms and conditions offered by producers.[85]

5.3. The upstream market is highly concentrated and dominated by the LNG exporters

The limited competition observed among producers is not surprising given the degree of concentration in this segment of the market.

As table 5.1 shows, the upstream segment of the east coast gas market is concentrated at present. This is particularly the case when measured on the basis of 2P reserves and production, with the top five producers accounting for 83% of 2P reserves and 85% of production in 2021. Although not shown in this table, the degree of concentration is also relatively high when measured on the basis of uncontracted gas, with just 13 producers with uncontracted gas available for sale in 2021, the top five of whom accounted for 73%. The number of producers with uncontracted gas is much lower than the number producing gas because a large number of producers have already sold their current production under medium to longer-term GSAs and so are not in a position to compete to sell gas.

In contrast to 2P reserves, production and uncontracted gas, there is a reasonable degree of diversity in holdings of 2C resources, with 35 producers having an interest in 2C resources as at 30 June 2021.[86] However, as table 5.1 highlights, the degree of concentration increases significantly as producers transition from holding 2C resources to producing and selling gas. This is not surprising given the significant geological, commercial, infrastructure, and regulatory barriers that producers can face when making the transition. While some junior producers have been able to overcome these barriers, others have not. Therefore, the degree of diversity observed in the holdings of 2C resources is unlikely to be replicated over time in holdings of 2P reserves, production or uncontracted gas.

That is not to say that improvements in upstream competition cannot be achieved. Rather, as we noted in our January 2022 interim report, there are steps that governments can take to encourage greater diversity in this part of the market and to reduce the infrastructure and regulatory related barriers that producers can face (see box 5.1).

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[84] See for example, ACCC, Gas inquiry 2017-2025 interim report, July 2020, Chapter 3, ACCC, Gas inquiry 2017-2020 interim report, January 2020, Chapter 3, ACCC, Gas inquiry 2017-2020 interim report, July 2019, Chapter 3, ACCC, Gas inquiry 2017-2020 interim report, December 2018, Chapter 3, ACCC, Gas inquiry 2017-2020 interim report, July 2018, Chapter 3, and ACCC, Gas inquiry 2017-2020 interim report, September 2017, Chapter 3,

[85] Some of the more notable changes in gas supply agreements that C&I users have identified, which we have also observed, include:

(a) lower load factors, which has reduced the ability of C&I users to manage daily variations in their demand

(b) higher take-or-pay percentages and the removal of banking rights (i.e. the right to 'bank' gas they have paid for but not taken and to use it at a later point in time), which has reduced the ability of C&I users to manage annual variations in demand and imposed greater financial obligations on these users

(c) the reduction or removal of supplier liabilities (with some agreements reportedly providing for limited or no compensation if the supplier is unable to deliver the contracted volumes), which means C&I users are more exposed to the risk that gas will not be supplied on a day and the operational risks that flow from this.

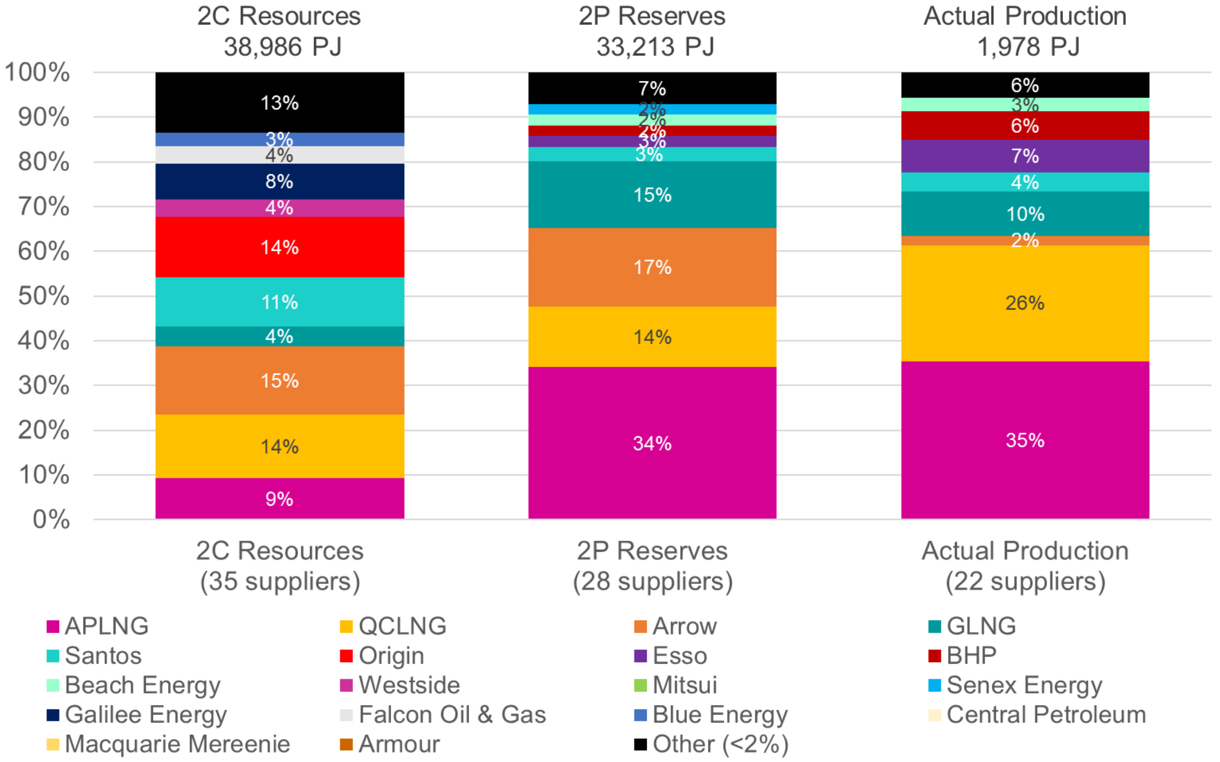
See for example, ACCC, Gas Inquiry 2017-2020 Interim Report, September 2017, Chapter 3, ACCC, Gas Inquiry 2017-2025 Interim Report, January 2020, pp. 68-69 and 77 and ACCC, Gas Inquiry 2017-2025 Interim Report, July 2020, pp. 67-68.

[86] This diversity can, in part, be attributed to the actions taken by the Queensland and South Australian governments, which have resulted in a greater number of junior producers being awarded tenements in the last 3-4 years.

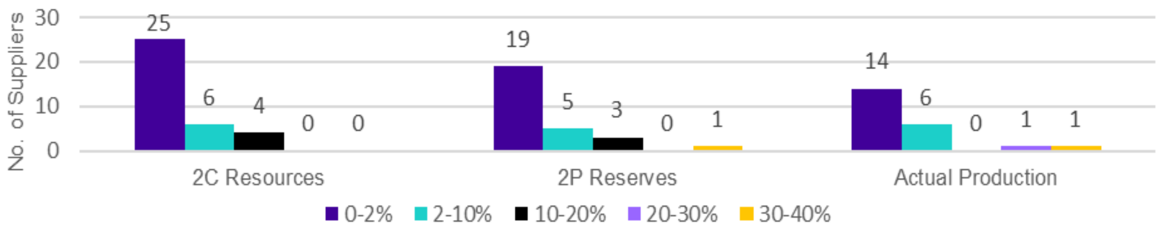
See for example, Queensland Department of Resources, 'Queensland gas exploration ramping up', 22 September 2020, https://www.dnrme.qld.gov.au/home/news-publications/news/2020/september/qld-gas-exploration-ramping-up and Dan van Holst Pellekaan MP, 'Successful applicants for Petroleum Exploration Acreage in Cooper and Otway Basins announced', 30 June 2020, https://www.premier.sa.gov.au/news/media-releases/news/successful-applicants-forpetroleum-exploration-acreage-in-cooper-and-otway-basins-announced.

Table 5.1: Degree of concentration in 2020-21

Concentration of 2C resources, 2P reserves and actual production



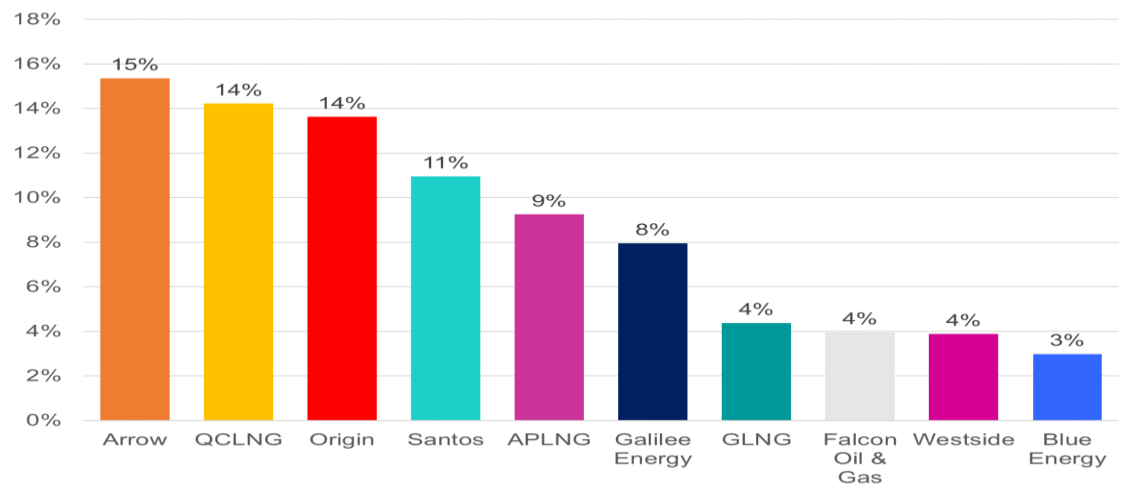
Distribution of producers by shares



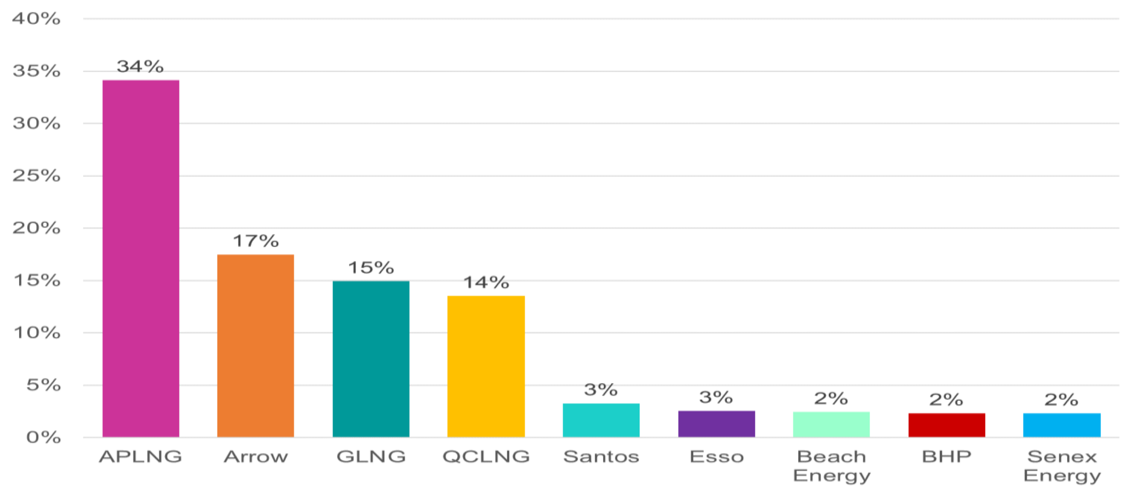
Summary metrics		**2C resources**	**2P reserves**	**Actual Production**
Share held by:	Top 5 suppliers	**63%** Arrow (15%), QCLNG (14%), Origin (14%), Santos (11%), APLNG (9%)	**83%** APLNG (34%), Arrow (17%), GLNG (15%), QCLNG (14%), Santos (3%)	**85%** APLNG (35%), QCLNG (26%), GLNG (10%), Esso (7%), BHP (6%)
	LNG exporters (+Santos+Arrow)	**28%** **(54%)**	**63%** **(83%)**	**71%** **(78%)**
Total no. of suppliers		35	28	22
No. of suppliers with <1% interest		22	17	13

Table 5.2: Holdings of 2C resources, 2P reserves and production in 2020-21

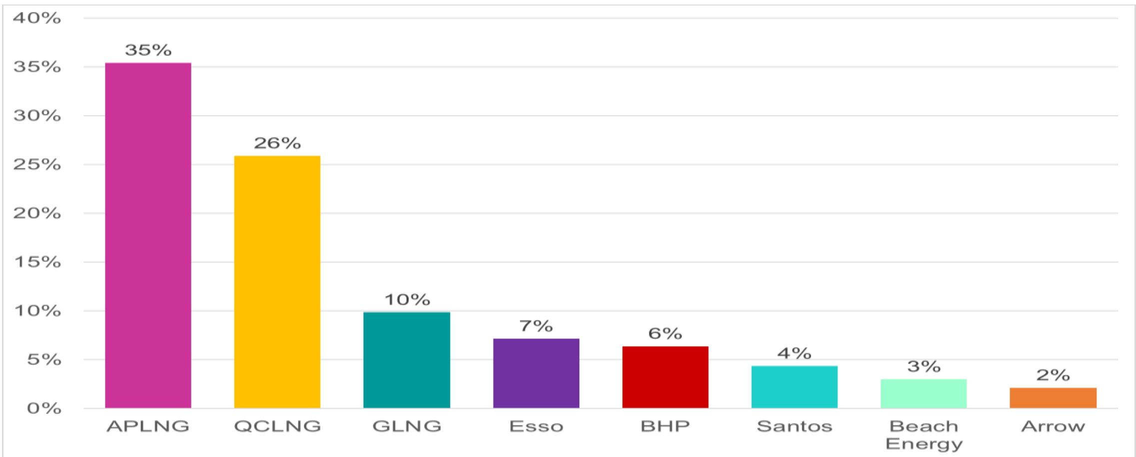
Holdings of 2C Resources



Holdings of 2P Reserves



Production



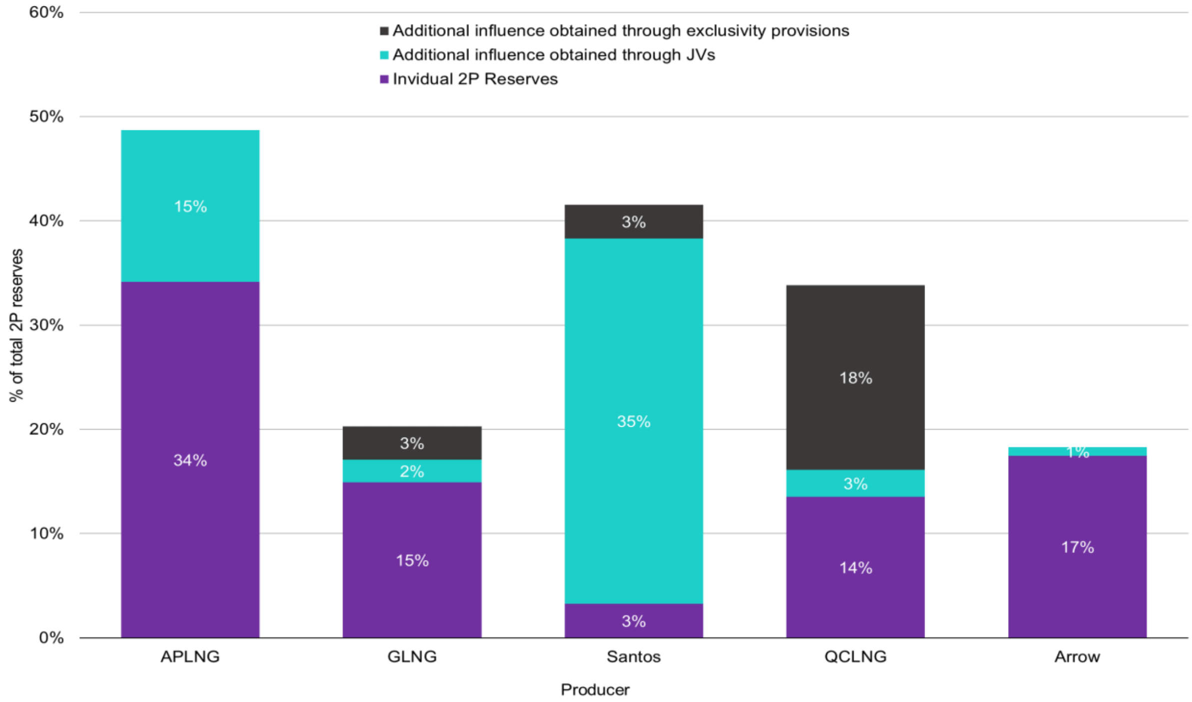
As table 5.1 shows, the LNG exporters (APLNG, GLNG and QCLNG) are quite dominant in the east coast gas market, jointly controlling 63% of 2P reserves and 71% of production.[87] Further, these metrics understate the true degree of influence that LNG exporters have in this part of the market, because they do not account for the interests of their associates. Nor do they account for the influence that LNG exporters have over supply as a result of:

- the JVs they are in with other producers (including other LNG exporters)
- the exclusivity provisions that a number of domestic producers are subject to under GSAs with the LNG exporters.

For instance, the metrics assume that the LNG exporters only have influence over their share of the 2P reserves in a JV, when in fact they can have influence over the total volume of 2P reserves held by the JV.[88] The metrics also fail to take into account the effective control that some LNG exporters have been able to obtain over the output of other producers through the inclusion of exclusivity provisions in GSAs (see section 5.6).

Chart 5.6 provides more insight into this issue and the extent to which the estimates in table 5.1 understate the influence that the LNG exporters had over the supply of gas from 2P reserves in the east coast in 2021.[89]

Chart 5.6: LNG exporters and associates' additional influence over 2P reserves (2021)



Source: ACCC analysis.
Note: The total share of 2P reserves in this chart exceeds 100% because a number of the producers are in JVs together and some also have exclusivity arrangements in place with other producers. The same 2P reserves may therefore be sitting in multiple columns in this chart. For example, if APLNG and GLNG were in a JV together that had 1,000 PJ of

87 Arrow in the case of QCLNG and Santos in the case of GLNG.

88 For example, if APLNG and GLNG were in a 50/50 JV that had 1,000 PJ of 2P reserves, then the concentration metrics presented in table 5.1 would assume they both had 500 PJ of 2P reserves, even though decisions by either APLNG or GLNG in the JV could affect the total volume of 2P reserves held by the JV (i.e. 1,000 PJ).

89 It is worth noting that this is a general problem with the concentration metrics presented in table 5.1 and is not unique to the LNG exporters and their associates. For example, the same analysis conducted for Esso, BHP and Beach revealed that their influence over 2P reserves is more than double what is presented in table 5.1, because of the JVs they are involved in.

2P reserves, then the 1,000 PJ would appear in both the GLNG and APLNG columns, because they both have influence over the 1,000 PJ.

As this chart shows, the market share estimates based on individual 2P reserves (as presented in table 5.1) significantly understates the influence that the LNG exporters and their associates have over the 2P reserves in the east coast. For example:

- APLNG's interest in a number of JVs with other producers means that it has influence over close to 50% of the 2P reserves in the east coast.
- GLNG's interest in a number of JVs, and exclusivity arrangements in GSAs it has entered into with Senex and Mitsui-Westside for the supply of gas from certain areas, means it has influence over 20% of 2P reserves in the east coast.
- Santos' interests in a number of JVs (including GLNG and other JVs in its own right), coupled with the exclusivity arrangements that GLNG has entered into (to which Santos is a party), means that Santos has influence over 42% of the 2P reserves in the east coast.
- QCLNG's interests in a number of JVs, coupled with the exclusivity arrangements it has entered into with Arrow for the supply from the Surat Gas Project, means QCLNG has influence over 34% of the 2P reserves in the east coast.

In each of these cases, the percentage of 2P reserves that the LNG exporters and their associates influence is substantially higher than what is presented in table 5.1. While not shown in chart 5.3, on an aggregate basis, the LNG exporters and their associates had influence over close to 90% of the 2P reserves in the east coast in 2021 through a combination of their direct interests in 2P reserves, JV and exclusivity arrangements. This highlights the LNG exporters' dominant position and the effective control that they have over the supply and development of gas in the east coast gas market.

As outlined in the following sections, the JV, joint marketing and exclusivity arrangements that LNG exporters have put in place, may also increase the risk of coordinated conduct and increase the market power of the LNG exporters.

This is concerning given the supply conditions expected in the east coast and the reliance that will be placed on the LNG exporters as a result.

5.4. Joint Ventures have helped producers to overcome barriers, but may harm competition and supply if effective ring-fencing is not in place

JV arrangements[90] are a common feature of the upstream segment of the east coast gas market, with over 95% of 2P reserves and 83% of 2C resources held through a JV as at 30 June 2021.[91] The prevalence of these arrangements is not surprising given the significant

[90] There are generally two forms that a JV can take: an incorporated JV or an unincorporated JV. An incorporated JV involves the establishment of a special purpose corporate entity to undertake the JV activity, with each JV party being a shareholder in the company. The terms of an incorporated JV are usually set out in a Shareholders' Agreement and the JV must also comply with the Corporations Act 2001 (Cth). An unincorporated JV, on the other hand, involves the JV parties coming together contractually through a JV Agreement, with each party owning a percentage interest in the assets of the JV and being responsible for its share of the expenses and product or service generated through the JV.

[91] Some of the more notable JVs in the east coast include:

(a) APLNG, which is an incorporated JV between Origin (27.5%), ConocoPhillips (47.5%) and Sinopec (25%)

(b) QCLNG, which is a JV between Shell (73.75%), CNOOC (25%) and Tokyo Gas (1.25%) comprising both incorporated and unincorporated elements

(c) GLNG, which is a JV between Santos (30%), Petronas (27.5%), Total (27.5%) and KOGAS (15%) comprising both incorporated and unincorporated elements

(d) Arrow, which is an incorporated JV between PetroChina (50%) and Shell (50%).

(e) the SA Cooper Basin JV, which is an unincorporated JV between Santos (66.6%) and Beach Energy (33.4%)

costs and risks that producers can face in the exploration, appraisal and production stages, with JVs providing for better access to financial resources and a means for producers to diversify their risks. Depending on the participants, a JV may also provide for better access to the infrastructure, technology and other resources required to bring gas to market.

While JVs have helped overcome some of the barriers associated with developing gas, they can also adversely affect competition if JV participants do not have robust ring-fencing arrangements in place to prevent the JV's supply, pricing and/or marketing information being shared with other projects or businesses in which JV participants have an interest.

JVs can also result in gas being brought to market more slowly than it otherwise would. This is because key decisions will usually require the agreement of the majority of participating interests. The decision of each participant will, however, depend on their individual circumstances. Some participants may, for example, be reluctant to invest in exploration, appraisal or production activities if they are facing financial or other resource constraints. Producers with interests in other projects may also be reluctant to invest if they are able to earn a higher return on other projects, or if they think delaying the JV's project would improve their competitive position in other projects.

5.4.1. Stakeholders cited a number of benefits of JVs but acknowledged they can affect the timeliness of supply

In the issues paper released in September 2021, stakeholders were asked whether there were any other ways that JVs could adversely affect competition and/or the timeliness of supply and if any steps could be taken to prevent this occurring.

Most of the producers that responded to this aspect of the issues paper focused on the benefits offered by JVs, in terms of providing participants access to the financial and other resources required to bring gas to market. A number of producers did, however, acknowledge that the inability of individual participants within a JV to agree on key decisions can affect the timeliness with which gas is brought to market.

Santos, for example, noted that while JVs offer a number of benefits (particularly to smaller producers), JV participants will have different risk appetites, funding abilities and views on marketing opportunities, all of which can affect decision making.[92] Arrow similarly noted that each JV participant will have their own risk appetite and can use their voting power to influence outcomes.[93] Shell also acknowledged that positions of a party in multiple JVs may result in sub-optimal outcomes through delays in decision making and projects being sanctioned. Shell went on to add that this is a risk factor in all JVs, which is typically managed through the inclusion of provisions that are designed to facilitate decision-making and to overcome misalignment of JV participants, such as voting thresholds, dispute resolution mechanisms and sole-risk operation provisions.[94]

The latter of these provisions can be used to overcome an impasse within a JV by allowing individual JV participants (or a sub-set) to proceed with the development if others choose not to participate. However, as one smaller producer noted in a confidential submission, the ability of individual participants to proceed with a project in their own right will depend on

(f) the GBJV, which is an unincorporated JV between Esso (~50%) and BHP (~50%).

At a tenement level, a number of these JVs are in JV arrangements with each other or with other producers. For example, APLNG and GLNG are JV partners in a number of tenements, and APLNG and QCLNG are JV partners in a number of other tenements.

92 Santos, Submission to ACCC review of upstream competition and timeliness of supply issues paper, November 2021, p. 10.

93 Arrow, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, p. 4.

94 Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, pp. 16-18.

whether they can secure sufficient funding to 'go it alone'. Arrow also noted that a 'sole risk' approach can be "challenging" for CSG because the development usually involves a large resource and long-term investment.[95] Arrow added that trying to segregate a sole risk project can be difficult and potentially uneconomic if the participant cannot access infrastructure. Arrow noted that while these issues could potentially be overcome through the inclusion of 'right of first refusal' or 'use it or lose it' provisions in JV operating agreements, such mechanisms should not diminish the purpose or benefits of parties entering into JVs.[96]

While acknowledging some of the limitations with JVs, producers did not consider any additional oversight of JVs was required. Origin, for example, stated that any additional measures or restrictions could distort commercial incentives, which may impact the timeliness of supply.[97] Santos and Shell expressed a similar view, noting that greater regulatory oversight would introduce more risk into projects and could adversely affect investment decisions.[98] Arrow made a similar observation and stated that "JV participants are best placed to determine the sharing of risks, costs and benefits under the JV".[99]

In contrast to producers, the MEU and EUAA suggested that more should be done to ensure that JVs do not impede competition and/or the timeliness of supply.[100]

5.4.2. Information provided by producers suggests most have ring-fencing arrangements in place, but some do not appear to be very robust

To better understand the effect that JVs may be having on upstream competition we issued notices to a sample of small and large producers and asked them for information on the ring-fencing arrangements that they have in place to ensure that:

- commercially sensitive information (e.g. information on actual or potential production and information on pricing and/or marketing to customers or prospective customers) obtained as a result of the producer's interest in any JVs are not shared with other projects or businesses in which the producer (or a related body corporate) has or gains an interest
- staff involved in the marketing, negotiation and/or sale of gas produced by any of the JVs that the producer has an interest in are not also involved in the marketing, negotiation and/or sale of gas in any other projects or businesses in which the producer (or a related body corporate) has or gains an interest.

Our review of this information indicates that most producers have implemented relatively robust ring-fencing arrangements.[101] However, there are a small number of producers that have either:

- implemented relatively weak ring-fencing arrangements (i.e. they don't effectively constrain the sharing of commercially sensitive information), or
- not formalised their ring-fencing arrangements.

95 Arrow, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, p. 4.

96 Arrow, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, p. 4.

97 Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 10.

98 Santos, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 11, Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, p. 18.

99 Arrow, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, p. 4.

100 MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 3-4.and EUAA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3.

101 Note that we have only been able to review the ring fencing arrangements and have not been in a position to test whether these arrangements are actually being adhered to by staff in these companies.

While the producers in these cases have claimed that the risks of anti-competitive behaviour are low, there is nonetheless a risk that these JVs could increase the potential for anti-competitive conduct which is concerning.

5.4.3. Producers should ensure they have effective ring-fencing arrangements in place

It is clear from our work in this area that JV arrangements have benefited the east coast market by helping producers overcome the significant financial, infrastructure and other barriers that can be faced in the exploration, appraisal and production stages. That said, we are concerned about the potential for JV participants to engage in anti-competitive conduct if effective ring-fencing arrangements are not put in place and adhered to by JV participants. If this were to occur then it could potentially raise concerns under a number of provisions in Part IV of the CCA, including:

- the making and/or giving effect to a contract, arrangement or understanding that includes a cartel provision (ss 45AF, 45AG, 45AJ and 45AK),[102] and/or
- the making and/or giving effect to a contract, arrangement or understanding, or engaging in a concerted practice, that has the purpose, effect or likely effect of substantially lessening competition in a market (s 45).

While the risk of non-compliance with the CCA ultimately rests with producers, we strongly encourage:

- those producers that have not formalised their ring-fencing arrangements, or that have put in place relatively weak arrangements, to implement more robust arrangements (an example of the type of arrangements that could be implemented can be found in the ring-fencing protocol the ACCC developed for the North West Shelf JV)[103]
- all producers to have an independent auditor regularly review compliance with the policies, because the effectiveness of these policies is critically dependent on the adherence of staff to these arrangements.

We understand that there are mechanisms in most JV arrangements that can be used to overcome the risk that differences in opinions and/or positions of JV participants can pose to the timely development of gas. However, as a number of producers observed, there appear to be some limitations in these arrangements, which may be exploited by some producers to delay the development of gas (e.g. to withhold supply to maintain or raise prices). We intend therefore to continue to monitor the behaviour of JV participants in terms of bringing gas to market in a timely manner and to identify producers that are delaying supply to market.

5.5. Joint marketing can harm competition; without authorisation it risks breaching the CCA

Historically, joint marketing was quite common in the east coast gas market across a large number of JVs, including the two largest domestically oriented suppliers (the GBJV and the Cooper Basin JV). The rationale typically provided for joint marketing was that separately marketing would require producers to put in place gas balancing arrangements, which they

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102 These provisions are subject to the application of the JV exemption under ss. 45AO and 45AP of the CCA, which can be satisfied where:

(a) the cartel provision is for the purposes of the joint venture and reasonably necessary for undertaking the joint venture

(b) the joint venture is for the production, supply or acquisition of goods or services, and

(c) the joint venture does not have the purpose of substantially lessening competition.

This exemption does not apply under s. 45 of the CCA.

103 See https://www.accc.gov.au/system/files/public-registers/documents/D10%2B3402432.pdf

claimed could be difficult, time consuming, and costly to implement. Some producers also claimed that separate marketing can be difficult in markets with few customers, limited trading markets and limited storage.

More recently, there has been a movement toward separate marketing, with a number of unincorporated JVs now operating jointly for the purposes of exploration and production, but separately marketing their share of the gas produced. For example:

- In 2010-11, the Cooper Basin JV participants (Santos, Origin and Beach) decided to start separately marketing their gas, with separate lifting commencing in 2015.[104]
- In 2017, the GBJV participants (BHP and Esso) decided that they would start to separately market their gas from 1 January 2019 (see box 5.4 for more detail).[105]
- A number of smaller JVs are separately marketing gas, including the Kipper JV (Esso, BHP, Mitsui), the BassGas JV (Beach and Prize Petroleum) and other JVs in the Otway and Bowen/Surat basins.

A similar trend has been observed in WA, with the North West Shelf JV (Woodside, Shell, BHP, BP, Chevron and MIMI), moving to separately market their domestic gas in 2015-16.[106]

The growing trend towards separate marketing suggests that many producers have found ways to overcome the hurdles outlined above and that joint marketing is not necessary for JVs to undertake the activities required to meet the purposes of the JV, namely, the exploration, production, and supply of gas. This appears to have been aided by the development of a more mature and liquid trading market in some parts of the east coast than has prevailed historically.

While separate marketing is becoming more common, there are still a number of relatively large JVs in the east coast engaging in joint marketing.

In this report, the term 'joint marketing' is used to refer to arrangements that limit individual participants in a JV (unincorporated[107] or incorporated[108]) from separately and independently marketing gas for supply into the domestic market.

Although the corporate structure and/or form of these arrangements may differ, they both involve two or more producers that could otherwise have competed, coming together to market and sell gas collectively or only sell gas domestically through the JV structure. In certain circumstances, the restraints on marketing options in JV arrangements may raise competition concerns under the CCA.

5.5.1. Producers pointed to the benefits of joint marketing, while users expressed concerns about its prevalence

In the issues paper, stakeholders were asked for their views on the impact that joint marketing may have on upstream competition and/or the timeliness of supply.

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104 Beach Energy, ASX Release New Transitional Gas Sales Agreement with Origin Energy, 10 December 2014. https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A834101/BPT_New_Transitional_Gas_Sales_Agreement_with_Origin_Energy.pdf

105 ACCC, BHP and Esso to separately market Gippsland Basin gas, 18 December 2017. https://www.accc.gov.au/media-release/bhp-and-esso-to-separately-market-gippsland-basin-gas

106 https://thewest.com.au/news/wa/historic-nws-gas-cartel-to-end-ng-ya-134248

107 Unincorporated JVs involve parties coming together contractually through a JV Agreement to pursue an activity, without forming a separate legal entity to carry on that activity. Each JV party owns a percentage interest in the assets of the JV, is responsible for a share of the expenses, and receives a share of the product or service generated by the JV.

Where a JV engages in joint marketing, it will often formalise the arrangement through a contract that restrains the parties to the JV from providing separate and competing offers to customers.

108 Incorporated JVs involve each JV party being a shareholder in a special purpose corporate entity. The arrangements of incorporated JVs are set out in a Shareholders' Agreement and other documents.

APPEA and a number of producers that responded to this question claimed that joint marketing can, in some circumstances, benefit consumers by allowing gas to be brought to market more rapidly than it otherwise would be and at a lower cost. APPEA for instance noted that:[109]

> *"In some circumstances, joint marketing can reduce the high costs and risks associated with oil and gas production investments. In this case, joint marketing can benefit consumers by providing greater availability of gas supply."*

Origin similarly noted that:[110]

> *"Joint marketing by unincorporated JVs is becoming less prevalent in the east coast gas market. However, it is clear there may be circumstances in which such arrangements may still be appropriate in the context of facilitating timely resource development."*

Shell also noted that joint marketing by CSG-LNG projects could benefit the domestic market relative to separate marketing:[111]

> *"…imposing a separate marketing requirement might not be the same for CSG-LNG projects as experienced with GBJV. In particular, it should be noted that some participants in the Queensland LNG projects hold relatively small shares and lack any existing east coast domestic marketing capability. For these entities, the cost to serve the domestic market could be disproportionately high. Some consequences of imposing separate marketing could be:*
>
> *- reduced appetite for further investment by smaller JV participants in sanctioning further upstream developments that would result in additional volumes for domestic marketing. Under these circumstances there would be less volume available for the domestic market;*
>
> *- the potential for smaller participants to be less active in the domestic market (for example looking to discharge their obligations with a few large sales rather than actively trading)."*

Some of the other reasons that producers cited in support of joint marketing are as follows:

- Reduced complexity: Some producers claimed that the balancing arrangements required to separately market gas can be difficult to implement, particularly in areas where the market is illiquid, immature and/or in the case of CSG lacks the infrastructure required to effectively manage the risk of production and demand mismatches.[112]
- Cost savings: Some producers claimed that joint marketing can: [113]
  - reduce the financial and operational burden (particularly for smaller producers and those that do not have a marketing presence in the east coast)

109 APPEA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 7.

110 Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 10.

111 Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, pp. 20-21.

112 See for example, CNOOC, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 5-6 , Arrow, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, p. 5, Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, pp. 19-22.

113 See for example, CNOOC, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 5-6, Tokyo Gas, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 2 and Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, September 2021, pp. 19-22.

    - give rise to operational synergies, reduced administrative burden, transaction cost savings and other cost efficiencies.
- Increased competition from smaller producers: Some producers claimed that joint marketing by smaller suppliers allows them to compete more effectively with other suppliers by allowing their gas to be aggregated into 'marketable sizes'.[114]
- Field development and investment: Some producers claimed that joint marketing assists JVs reach agreement on field development plans and ensures investment decisions can be taken at the same time, which facilitates more timely supply.[115]

In contrast to the views expressed by some producers on the complexities associated with implementing gas balancing arrangements, APLNG noted that:[116]

> *"Most model form joint operating agreements include standard balancing arrangements that can generally be applied on a commercial basis in most circumstances. These model form arrangements reduce barriers to negotiating suitable balancing arrangements."*

Another small producer noted in a confidential submission that:

> *"Gas balancing works when the parties have a reasonably accurate estimate of the ultimate reserves that will be produced. …Joint marketing is probably useful early on in the field's life, when the field(s) are still being developed and there is less certainty on the ultimate volumes to be produced. Later on, with more production history, there will be more confidence in the reserves and balancing will make more sense."*

In contrast to producers, the MEU expressed concerns about joint marketing, noting that while joint marketing may be appropriate where there is a monopsony or large buyers, this is no longer the case in the east coast gas market, with buyer competition having increased significantly over the last two decades.[117] The EUAA also expressed concerns about joint marketing and noted that since the GBJV ceased joint marketing, there has been more competition in the market (see box 5.4):[118]

> *"We consider that the ACCC authorising joint marketing should be the exception rather than the rule. The Issues Paper points to the benefits since the Gippsland Basin JVs started separate marketing. Our members' experience supports this conclusion. We support the ACCC reviewing as a matter of course, current joint marketing arrangements (for both incorporated and unincorporated JVs) that are not authorised."*

Box 5.4: Movement to separate marketing by the GBJV

The GBJV is an unincorporated JV between BHP and Esso for the production of crude oil and natural gas at the offshore fields in the Gippsland Basin in Victoria. The GBJV was established in 1964 and began jointly marketing its gas to customers when it commenced production in 1969.

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[114] Westside, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 4-5 and Vintage Energy, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 6.

[115] APPEA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 7 and Westside, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 4-5.

[116] APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 12.

[117] MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 6.

[118] EUAA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 5.

Concerns about the GBJV's joint marketing arrangements were raised during the ACCC's 2015 inquiry. The report stated that the effect of the lack of diversity of suppliers in the southern states was being exacerbated by the joint marketing arrangements of the GBJV. Further, it referred to the ACCC's preliminary review of the GBJV joint marketing arrangements in 2010 following which the ACCC decided to take no further action at that time, but advised the JV partners that it might revisit the matter if future market developments warranted doing so.

The ACCC's 2015 inquiry found that the GBJV held significant market power as a result of the changed competitive dynamics in the southern states since 2010, particularly for southern gas users. The Inquiry considered that joint marketing by the GBJV may have a more detrimental impact on competition than in the past and that it warranted reconsideration by the ACCC.

As a result, the ACCC stated it would consider the competitive effect of the joint marketing arrangements of the GBJV in light of market dynamics, for the purposes of s. 45 of the CCA.

This matter was referred for further investigation. Following the ACCC's investigation, Esso and BHP provided court enforceable undertakings to separately market their share of gas produced under the GBJV from 1 January 2019.

In the period following the separate marketing of gas by the GBJV, we have seen increased competition between the two parties in terms of their offers and agreed contract terms.[119] AEMO has also observed BHP and Esso increasing the volume of gas offered to the Victorian and Sydney short term markets with offers at different prices.[120]

Some users were also surprised by the fact that incorporated and unincorporated JVs were engaging in joint marketing without ACCC authorisation (see box 5.5).

[119] ACCC analysis of data relating to market offers and GSAs.

[120] AEMO, Quarterly Energy Dynamics, Q2 2019, p. 25.

Box 5.5: Authorisation of joint marketing

Section 88 of the CCA allows the ACCC to authorise conduct that may otherwise breach one or more of the competition provisions in Part IV of the CCA. In assessing an authorisation application, the ACCC will consider the individual circumstances, including the impact that the conduct could have on competition and the public benefits and detriments associated with the conduct.

In the last five years, the ACCC has received the following applications for authorisation to engage in joint marketing:

- Central Petroleum-Macquarie Mereenie JV submitted an application in 2017 to jointly market gas (approximately 15 PJ p.a.) from the Mereenie field in the NT, which was granted.[121] The ACCC re-authorised these joint marketing arrangements in 2022, with a condition,[122] for five years.[123]
- The Vali JV (Vintage, Metgasco and Bridgeport) submitted an application in 2020 to jointly market (approximately 0.3 PJ p.a.) from the Vali field in the Cooper Basin for a five year period. The ACCC granted authorisation in 2021.[124]

The producers in both of these cases were new entrants and the volume of gas to be jointly marketed was relatively small. In both of these cases the ACCC found that the public benefits would likely outweigh any public detriment, with the principal benefit being that joint marketing would allow gas to be brought to market earlier than it may otherwise be.

5.5.2. A number of large JVs are jointly marketing gas in the east coast without authorisation under the CCA

To better understand the prevalence of joint marketing in the east coast, we issued notices to a sample of small and large producers and asked them for information on their marketing arrangements. The information they provided shows that while separate marketing has become more common in the east coast, there are still a number of large incorporated and unincorporated JVs that are in effect engaging in joint marketing,[125] including.

- APLNG, which is an incorporated JV between ConocoPhillips (47.5%), Origin Energy (27.5%) and Sinopec (25%)
- QCLNG, which is a JV between Shell (73.75%), CNOOC (25%) and Tokyo Gas (1.25%)
- GLNG, which is a JV between Santos (30%), Petronas (27.5%), Total (27.5%) and KOGAS (15%)
- Arrow, which is an incorporated JV between Shell (50%) and PetroChina (50%).

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121 ACCC, Determination Application for authorisation lodged by Central Petroleum, 29 March 2018 https://www.accc.gov.au/system/files/public-registers/documents/AA1000398%20-%20Central%20and%20Macquarie%20Mereenie%20-%20Final%20Determination%20-%2029.03.18%20-%20PR.pdf

122 The condition requires the JV participants to notify the ACCC at least 30 days before any business that is not a current JV participant becomes a participant in the Mereenie JV and engages in joint marketing under the authorisation. This will enable the ACCC to consider whether the addition of any new participant might constitute a material change of circumstances and warrant review of the authorisation.

123 ACCC, Determination Application for authorisation lodged by Central Petroleum, 27 January 2022 https://www.accc.gov.au/system/files/public-registers/documents/Final%20Determination%20-%2027.01.22%20-%20PR%20-%20AA1000564%20Macquarie%20Mereenie.pdf

124 ACCC, Determination Application for authorisation lodged by Vintage Energy, 13 May 2021 https://www.accc.gov.au/system/files/public-registers/documents/Final%20Determination%20-%2013.05.21%20-%20PR%20-%20AA1000538%20Vali%20Gas.pdf

125 As noted in the introduction to this section, the term 'joint marketing' is used throughout this report to refer to both joint marketing by parties in an unincorporated JV and marketing by an incorporated JV.

The scale of these four JVs can be seen in table 5.1, with the three LNG exporters and Arrow accounting for 83% of 2P reserves and 73% of production in the east coast gas market in 2021.[126]

These four JVs supplied around 230 PJ of gas into the east coast market in 2021, which represents around 41% of domestic demand. All of this gas was supplied to the domestic market under joint marketing arrangements. The ACCC has not authorised any of these marketing arrangements, nor have any of these JVs sought ACCC authorisation.

If the parties behind each of these JVs were to separately market gas in the east coast, then it would result in the number of producers competing to supply the gas produced by the JVs potentially increasing from 4 to 12.[127]

The term 'potentially' is used because it is possible that some of the JV participants may decide not to supply the domestic market. For example, JV participants with smaller interests in the LNG projects, or with limited gas in excess of their long-term SPA commitments, may choose not to supply the domestic market. JV participants that have a preference to supply international markets rather than the domestic market may also choose not to supply the domestic market. CNOOC (a party to the QCLNG JV), for example, stated in its response to our issues paper that it had "no intention to equity lift and market its own gas". CNOOC also noted that while it "bought into the project with an interest to produce and sell LNG" it had committed to " sell gas to the domestic market in line the HoA",[128] which highlights the importance of the HoA and the ADGSM in ensuring the LNG exporters supply gas into the domestic market.

Even if some of the LNG JV participants decided not to compete to supply gas into the domestic market, there would still be a doubling of producers competing to supply the gas produced by these JVs into the domestic market, which should result in an increase in competition. Further, while some of the LNG JV participants may choose not to supply their share of any excess gas into the domestic market, it does not necessarily follow that less gas would be supplied into the domestic market by the LNG projects relative to what would occur if they continued to jointly market gas. This is because those that choose to supply their excess gas into the domestic market may decide to supply more than would otherwise be the case under joint marketing, because they don't have to reach a compromised position with a party that does not want to supply any gas into the domestic market.

Our review of the material provided by participants in the LNG exporter JVs shows that the marketing arrangements were primarily established for sales of LNG. However, marketing arrangements employed for domestic sales need not mirror those for LNG exports. The purpose of the LNG projects is to produce LNG for international markets. It is difficult to see why jointly marketing gas to the domestic market would be necessary in order to produce and export LNG. The ACCC therefore encourages the LNG exporters to reconsider their marketing arrangements for the domestic market, particularly given the material role they are expected to continue to play in the domestic market over the immediate to longer-term. An extended and strengthened HoA and ADGSM could assist in this regard, by extending obligations to individual participants in the LNG JVs.

126 These figures exclude the shares of Santos and Arrow. The share of 2P reserves and actual production increases to 83% and 78% respectively if the gas of Santos and Arrow is included.

127 We note that changing marketing arrangements may take some time and present some difficulties. This is the case for both incorporated and unincorporated joint ventures. In the case of the GBJV, the ACCC accepted court enforceable undertakings from Esso and BHP which allowed around 12 months for both parties to transition from joint marketing to separate marketing. The undertakings also allowed Esso and BHP to continue to be bound by and give effect to GSAs entered into as a result of their joint marketing.

128 CNOOC, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 3

In addition to these instances of joint marketing, we understand that Beach and OGOG have recently agreed to jointly market gas from the Enterprise field in Victoria's Otway Basin. The Enterprise field has 160 PJ of 2P reserves and given its location in Victoria, is well placed to supply the southern states which are most at risk of supply shortfalls. The ACCC has not authorised these joint marketing arrangements, nor have Beach or OGOG sought ACCC authorisation.

We also understand that some smaller JVs are considering whether to engage in joint or separate marketing from new fields in the east coast.

5.5.3. Separate marketing should be the default; joint marketing without authorisation risks breaching the CCA

Arrangements for the marketing of gas are typically complex. The potential impact on competition and/or supply will be determined by the specific facts and circumstances of a particular arrangement.

The ACCC has a strong preference for gas to be separately marketed. While producers have cited a number of impediments to separate marketing, the fact that a growing number of producers have moved to separately marketing their gas suggests that they have been able to overcome these. This has been aided by the development of a more mature and liquid market in most parts of the east coast than has prevailed historically.

Recent events across the east coast gas and electricity markets have shown the consequences of having insufficient gas supply to meet domestic demand and ineffective upstream competition. With supply conditions expected to deteriorate further in 2023, the need for separate marketing has never been stronger.

The ACCC therefore encourages JVs that are engaging in joint marketing to consider implementing the changes required to enable individual JV participants to separately market gas.

Also, we note that the risk of non-compliance with the CCA rests with producers. Where joint marketing would result or be likely to result in a net public benefit (i.e. the public benefit would outweigh the public detriment that would be likely to result), the CCA provides an avenue for parties to seek authorisation. While two examples of recent authorisations of joint marketing were described in box 5.5, there are some distinguishing factors that underpinned the assessment of public benefits and detriments leading to the ACCC's decision to grant those authorisations. These factors may not be applicable in other instances where producers seek to jointly market gas and applications for authorisation are assessed on a case-by-case basis.

We intend to undertake a closer review of instances of joint marketing that are currently occurring without authorisation and, where appropriate, consider enforcement action.

5.6. Exclusivity provisions can impede competition and timely supply and, depending on their nature, may also raise CCA concerns

Exclusivity provisions[129] in GSAs entered into between producers can operate in a number of ways to reduce the degree of upstream competition and may also affect the timeliness with which gas is brought to market.

[129] The term 'exclusivity provisions' is used in this context to refer to any provisions in a GSA that restrict the way the selling producer may market gas. This includes explicit exclusivity clauses, in which the seller agrees to exclusively supply gas to the buyer, and clauses that provide the buyer with a first or last right of refusal to any additional gas produced by the seller.

These provisions limit the ability of the selling producer to sell gas from a particular area to anyone other than the buying producer. They may also affect the incentive the selling producer has to develop gas if the price in the GSA is set too low (i.e. because the exclusivity provision limits their ability to sell the gas to anybody else).

Depending on the nature of the exclusivity provision it may raise concerns under Part IV of the CCA if it has a purpose, effect or likely effect of substantially lessening competition.

5.6.1. Producers pointed to the potential benefits of exclusivity provisions, while users expressed concerns about their impact on competition

In the issues paper, stakeholders were asked for their views on exclusivity provisions in GSAs between producers. Stakeholders were also asked for their views on how to address any restriction on competition caused by exclusivity provisions, and whether these arrangements should only be entered into if producers have sought authorisation.

Responses to these questions were received from a number of producers and LNG exporters, including those that are party to a GSA with an exclusivity provision. One of those LNG exporters noted in a confidential submission that the exclusivity arrangement it has entered into with smaller producers were agreed on the basis that the selling producer wished to commit gas reserves to the LNG exporter, but did not have the financial capability or risk appetite to make a firm long term commitment. It claimed the exclusivity provision overcame these issues and provided the selling producers flexibility to provide the LNG exporter with gas depending on the gas development achieved.

A similar view was expressed by another LNG exporter in a confidential submission. This LNG exporter claimed that exclusivity provisions can allow selling producers to de-risk their project and allow more capital to be committed to the development of upstream resources.

In its submission, Westside acknowledged that its GSA for supply from a portion of the Greater Meridian field includes an exclusivity provision. It noted that this exclusivity provision, coupled with other factors, such as the credit worthiness of the buyer, the long term nature of the GSA, and the flexibility regarding field development, allowed it to secure debt finance that would otherwise not have been available. It added that the exclusivity provision had allowed the Meridian JV to bring additional gas to market and had increased competition in the market.[130] Cooper Energy made similar observations, noting that these arrangements can facilitate investment in new developments and therefore support new gas supply.[131]

Producers were of the view that no additional regulation of these arrangements is necessary.[132] They did, however, state that if these arrangements are substantially lessening competition, they could be considered under the CCA.[133]

In contrast to producers, the MEU stated that any removal of a potential competitor from the market as a result of an exclusivity provision would reduce competition to the detriment of consumers. It suggested that the ACCC investigate whether the GSAs that contain these provisions breach the CCA. It also suggested that any producers that are considering entering into exclusivity provisions apply to the ACCC for authorisation before doing so.[134]

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130 Westside, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, submission, p. 5.

131 Cooper Energy Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 4.

132 Westside, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 5, Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 12.

133 Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 12.

134 MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 7.

5.6.2. While exclusivity provisions are not common, they have been included in a small number of sizable GSAs with LNG exporters

To better understand the prevalence of exclusivity provisions in GSAs between producers, we issued notices to a sample of small and large producers.

Based on the information we received it appears that while these types of provisions are not common, they have been included in a small number of GSAs involving LNG exporters as the buyers, which provide for the supply of material volumes of gas (with 2P reserves ranging from 430 PJ to 5,800 PJ[135]) over relatively long periods (18 to 27 years).

While each arrangement is bespoke, the exclusivity provisions in each of the GSAs limit the ability of the selling producer to compete to supply gas produced in the defined area to other buyers in the market. Some of the GSAs also allow the parties to agree to add other areas to the defined area over time.

All of the GSAs contain some exceptions to the exclusivity provisions, to accommodate things like:

- the buyer's failure to take nominated gas
- interruptions and force majeure events
- the supply by the selling producer under legacy GSAs
- domestic supply obligations (if imposed on the seller), and/or
- whether the seller has met performance obligations, such as supplying a specified volume of gas.

However, some of these exceptions are subject to a first right of refusal for the buyer or are accompanied by other restrictions. For example, the performance obligation exception in one GSA allows the producer to supply a certain amount to third parties subject to a most favoured nation style provision, which prevents the seller offering gas to third parties at a lower price than that offered to the LNG exporter. Another GSA states that if gas is not taken under the exception, then it must be made available to the LNG exporter, and only if the LNG exporter elects not to take the gas can it be sold to others.

5.6.3. The restrictions imposed by the exclusivity provisions on selling producers competing in the market is concerning

The GSAs with exclusivity clauses that we have identified:

- restrict the selling producer from competing to supply gas into the market for relatively long periods of time
- provide for a significant degree of cooperation between potential competitors.

While the parties to these GSAs have cited a number of potential benefits with the arrangements (e.g. in terms of reducing risk or providing for access to capital), it is not clear:

- why it was necessary to restrict the actions of the selling producer through the inclusion of an exclusivity provision
- why the same benefits could not have been achieved through other means.

Setting this aside, the ACCC is concerned that the inclusion of these exclusivity provisions could result in the removal of the selling producer as a competitor in the market, or could

135 2P reserve figures as at April 2022 for areas currently subject to an exclusivity provision, and are on a life of field basis.

otherwise limit their ability to compete to supply gas in the market. We are also concerned that these arrangements could:

- lead to development decisions being based on the requirements of the LNG exporters, rather than the domestic market
- further weaken competitive constraints on the LNG producers because of the following features of the arrangements:
  - the significant volumes of reserves and resources that are subject to the exclusivity arrangements and the ability that the parties have to extend the arrangements to other areas
  - the long term nature of these GSAs, with the terms ranging from 18 to 31 years
  - the additional visibility provided by annual reserves and resources estimates and other technical information, and in one case, the terms of competing offers by third parties.

These types of provisions may raise concerns under Part IV of the CCA if they have the purpose, effect or likely effect of substantially lessening competition. We intend therefore to undertake a closer review of these GSAs and, where appropriate, consider enforcement action.

In a similar manner to joint marketing, there is a heightened risk in a concentrated and relatively tight market that GSAs containing exclusivity provisions could adversely affect competition. We therefore encourage any producers that are considering entering into these types of arrangements to carefully consider the provisions in Part IV of the CCA, and to apply for authorisation under the CCA if they decide to proceed.

5.7. Mergers and acquisitions by larger producers can impede competition and supply and should be subject to review

Like JVs, mergers between producers, or acquisitions by producers of individual tenements or interests in a JV, can affect the degree of upstream competition and the timeliness with which gas is brought to market.

For example, if a larger producer was to merge with a smaller producer that has just commenced supplying gas to market, or acquires the tenement from which gas is to be supplied, it would result in a reduction in the number of producers competing to supply gas in the market. The merger or acquisition could also slow the progress of the development of gas if the larger producer already has substantial reserves and resources and faces some financial or other resource constraints. If the larger producer was to enter into a JV with the smaller producer, it could also result in a reduction in competition.

5.7.1. Stakeholders had mixed views on mergers, with producers pointing to their benefits, while users were concerned about their impact

In the issues paper, stakeholders were asked for their views on the impact of mergers and acquisitions on the upstream segment of the market. They were also asked about the efficacy of the current merger regime.

APPEA and a number of producers that responded to these questions noted that in their view the current regime is working effectively, and mergers and acquisitions in the industry had allowed gas to be developed in a more timely and efficient manner than would otherwise be the case (i.e. by providing access to capital and other resources). They were therefore opposed to any changes to the current merger regime and notification requirements. [136]

Some producers noted that if a sector specific regime was implemented, or greater ACCC oversight required, it could have a range of unintended consequences and result in greater delays and/or less gas coming to market.[137] Santos, for example, noted that the requirement to obtain ACCC approval, could "prevent assets changing hands to parties with capacity and desire to develop, which could contribute to companies holding acreage that they do not intend to develop or lack capacity to develop".[138]

In contrast to producers, the MEU expressed some concerns about mergers and acquisitions in this part of the market. It noted that the fact that the gas market is still highly concentrated despite the efforts of Queensland and other state governments to increase competition through the permit process, implies that either the upstream segment has "attributes that do not encourage competition and/or that the laws are inadequate".[139]

5.7.2. Producers have entered into a number of mergers and acquisitions over the last five years

To better understand the impact of mergers and acquisitions on upstream competition, we issued notices to a sample of small and large producers seeking information on the mergers and acquisitions that they had been a party to in the last five years.

The information provided by producers in response to the compulsory information notices indicates that they have entered into a number of mergers and acquisitions over the last five years, some of which the ACCC examined through the informal clearance process, while others were not.

Those transactions where the ACCC was not notified included acquisition by:

- larger producers of small producers, individual tenements and/or interests in JVs.
- smaller producers of tenements that larger producers are no longer developing.[140]

These acquisitions may be less likely to raise competition concerns and, in the case of the acquisitions by smaller producers could benefit the market if it results in additional gas being supplied into the market. Denison Gas' acquisition of Santos' Denison Trough assets in 2018, for example, has resulted in production from fields that were previously shut in being brought back into operation and supplied into the east coast market.[141] Comet Ridge's

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136 See, for example, APPEA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 6, APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 9-10, Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 10, Santos, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 11 and Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 18-19.

137 See, for example, APPEA, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 6, APLNG, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 9-10, Origin, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 10, and Shell, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, pp. 18-19,

138 Santos, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 11.

139 MEU, Submission to ACCC review of upstream competition and timeliness of supply issues paper, October 2021, p. 7.

140 For example, in 2018 APLNG and Santos sold their interests in a number of tenements in the Denison Trough to Denison Gas (see https://denisongas.com.au/news-1/). In 2021, APLNG also sold its interest in the Mahalo Project to Comet Ridge (http://www.cometridge.com.au/wp/wp-content/uploads/2021/08/2021.08.03-COI-Funded-Acquisition-of-APLNGs-30-of-Mahalo-Gas-Project.pdf).

141 https://denisongas.com.au/media-release-denison-gas-signs-8-pj-gsa-with-agl/

acquisition of APLNG's interest in the Mahalo Gas Project in 2021 is also expected to result in gas being brought to market more rapidly than it may otherwise have been.[142]

5.7.3. The risks to competition posed by mergers can be heightened in a tight market, so producers should use the merger review process

Effective merger control ensures that markets remain competitive and prevents increases in concentration that could lead to anti-competitive practices. Australia's informal merger regime is one of a few worldwide that does not include a mandatory and suspensory requirement. The ACCC relies on the willing compliance of merger parties to advise us of proposed mergers and provide us with sufficient time and information to conduct our review. The ACCC is increasingly facing practical challenges with merger parties pushing the boundaries of the informal system. Such concerns and challenges have prompted consideration of whether our regime remains fit for purpose.

In August 2021, the ACCC outlined some options for merger law reform and started a discussion as to whether there is a need for reform, including moving away from the voluntary informal merger regime.[143] Importantly, the reform options outlined by the ACCC do not involve a sector specific regime that would only apply to the gas market. They could, however, require merger parties to notify the ACCC of all proposals above a specified threshold and delay completion until the ACCC has considered the likely competitive effects of the proposal. Development of any such options would be subject to broad consultation, drawing on international best practice, including around setting thresholds and ensuring there are streamlined processes to reduce the burden on merger parties. The ACCC will continue to seek and consider feedback on the options, but ultimately it will be a matter for the Commonwealth Government to progress any reforms in this area.

Setting aside the potential reforms in this area, it is clear from the concentration analysis in section 5.3 that the upstream market is already highly concentrated. In such a market, with conditions continuing to tighten, there is a heightened risk that mergers and acquisitions (including by way of the acquisition of an interest in a JV) by larger producers, could result in a substantial lessening of competition. We therefore encourage producers to consider whether their proposals may raise competition issues and, if so, to:

- seek the ACCC's views using the informal merger process, and/or
- seek a merger authorisation from the ACCC, which provides businesses with protection from legal action under the merger provisions in the CCA including where the proposal is likely to result in overall public benefits.[144]

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142 http://www.cometridge.com.au/wp/wp-content/uploads/2021/08/2021.08.03-COI-Funded-Acquisition-of-APLNGs-30-of-Mahalo-Gas-Project.pdf

143 https://www.accc.gov.au/speech/protecting-and-promoting-competition-in-australia

144 CCA, ss 88 and 90.

A. Domestic price outlook in 2022

A.1 Introduction

This appendix presents information on wholesale gas commodity prices in the east coast gas market for supply in 2022.

Specifically, the ACCC reports on:

- prices offered, and bids received, by gas producers and retailers (section A.2.1)
- prices offered in Queensland and the southern states relative to expected LNG netback prices (section A.2.2)
- prices agreed by gas producers and retailers (section A.3.1)
- the level of flexibility agreed by producers and retailers (section A.3.2).

This is the final report in which the ACCC will report on wholesale gas commodity prices for supply in 2022.

The prices reported in this appendix reflect wholesale gas commodity prices in offers, bids and GSAs which have a term of at least 12 months, an ACQ of at least 0.5 PJ, and are made or entered into at arm's length. A complete explanation of the ACCC's approach to reporting on prices is presented in appendix B.

Where the ACCC reports on an average price in this appendix, it is a quantity-weighted average wholesale gas commodity price.

A.2 Offers and bids

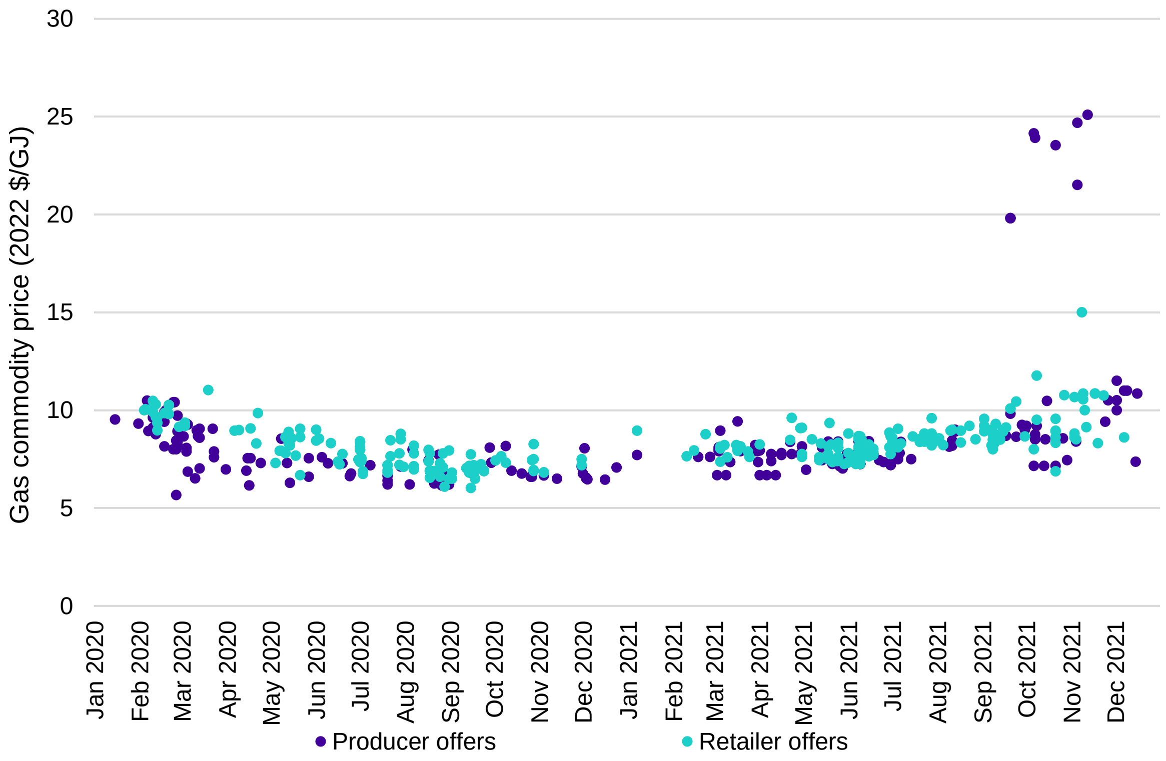
In reporting on offers made and bids received by suppliers, the ACCC included only those offers and bids that contain clear indications of price, quantity, supply start and end dates, and estimated the price for each offer and bid using the approach outlined in appendix B.

The analysis of offer and bid prices in this chapter is intended to provide an indication of price trends over time. As explained in appendix B, the prices of individual offers and bids are not necessarily comparable as they can differ in non-price aspects, such as delivery location, quantity, contract term and contract flexibility. Offer and bid pricing in some instances may also reflect seasonal price fluctuations, linkages to prices of other commodities (such as oil), price expectations over the length of the contract (not only the supply year in discussion) or, in the case of GPG, conditions in the electricity market.

A.2.1 Offers and bids

Chart A.1 shows offers made by producers and retailers for 2022 supply over the period from 1 January 2020 to 31 December 2021.

Chart A.1: Gas commodity prices offered in the east coast gas market for 2022 supply ($2022/GJ)



Source: ACCC analysis of offer information provided by suppliers.

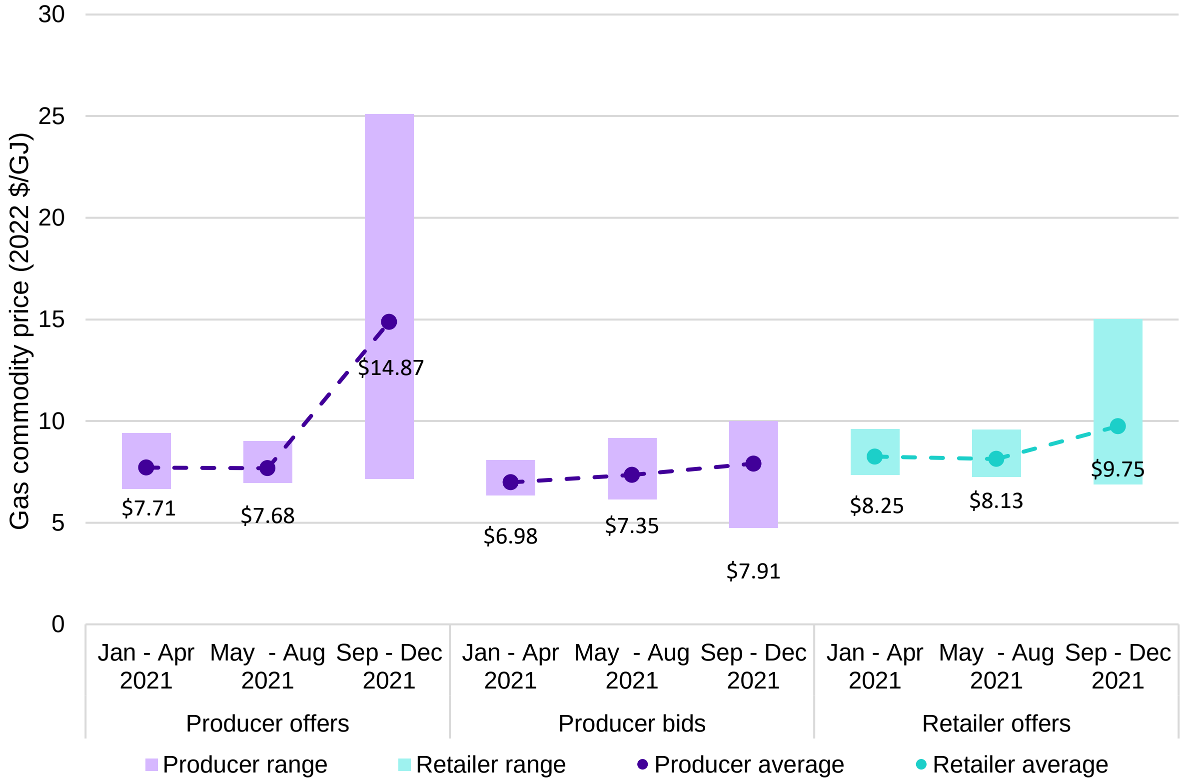
Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA.

In January 2022, we reported on offers made and bids received by suppliers between 1 January 2020 and August 2021, for supply in 2022. For completeness, this report extends the analysis of pricing for supply in 2022 that was offered up to December 2021. Prices offered by gas producers and retailers for supply in 2022 fell from a range of $5– 11/GJ in early-to-mid 2020 to $5–10/GJ in late 2020 to early 2021. From August 2021 to December 2021 prices offered have increased. Prices ranged from around $6.50/GJ to $25/GJ.

Chart A.2 compares quantity-weighted offers made and bids received by producers (to all buyers) and by retailers (to C&I users) for gas supply in 2022 in three periods:

- Period 1 (January 2021 to April 2021),
- Period 2 (May 2021 to August 2021),
- Period 3 (September 2021 to December 2021)

Chart A.2: Gas commodity prices offered and bid in the east coast gas market for 2022 supply ($2022/GJ)



Source: ACCC analysis of offer information provided by suppliers.

Note: Quantity-weighted average prices are displayed below the price range. Bids made to retailers were excluded from the chart because an insufficient number of bids were made to retailers by C&I users.

In January 2022, we reported that quantity-weighted average prices offered for 2022 supply was relatively stable. Prices ranged between $7 to $8 per GJ from January 2020 to August 2021. The analysis of average bids and offers for supply in 2022 has been extended to include the remaining months of 2021 (period 3).

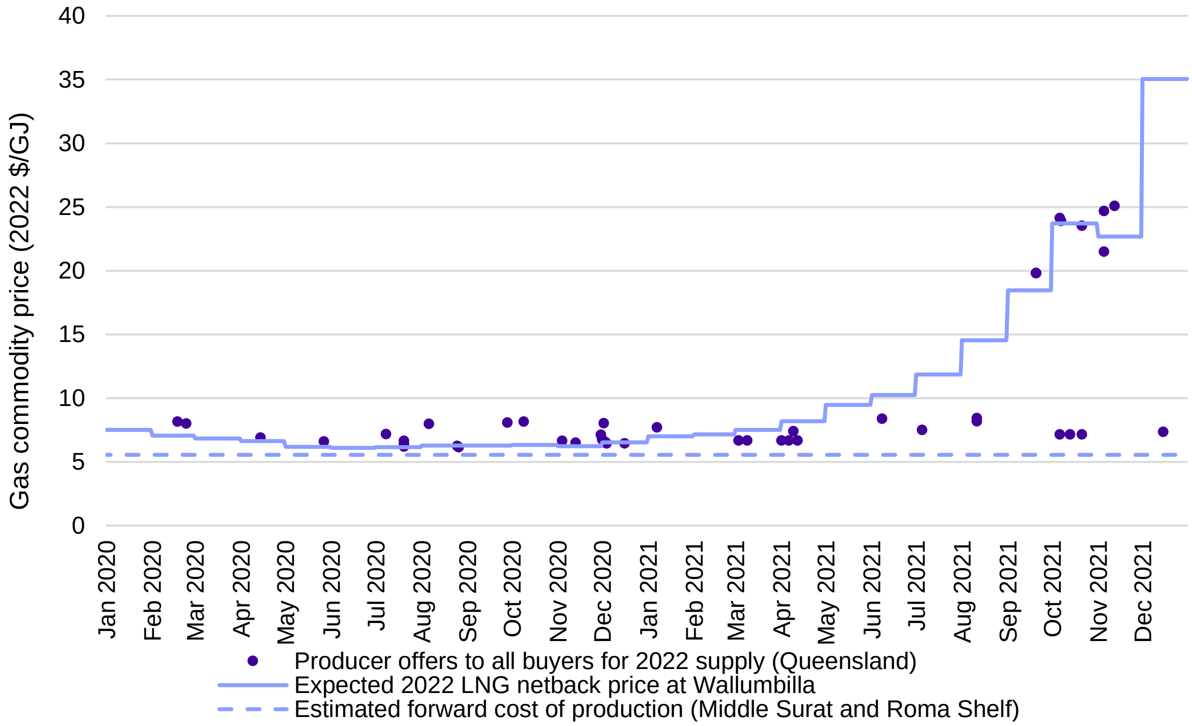
Since August 2021, there has been a significant increase in the average prices offered for supply in 2022. Quantity-weighted average prices offered by producers increased 94% from periods 2 to 3. This was driven by a number of offers from LNG exporters linked to a higher LNG netback. These offers can be seen in chart A1, with a range between $20 and $25.

Average retail prices offered to C&I users also increased over this period, by 20%.

A.2.2 Netback and domestic offers comparison (Queensland)

Chart A.3 charts offers made by producers between 1 January 2020 and 31 December 2021 for supply in Queensland in 2022 against expectations of 2022 LNG netback prices (as at the time the offer was made).

Chart A.3: Gas commodity prices offered by producers to all buyers for 2022 supply in Queensland ($2022/GJ)



Source: ICE, Argus, ACCC analysis of other information provided by suppliers.

Note: The above chart only includes offers that relate to contracts with a term of 1–3 years. Offers that specify pricing mechanisms linked to oil prices have been excluded.

Our January 2022 interim report observed that from March to August 2021 the expected LNG netback price exceeded domestic offers for supply in Queensland. Chart A.3 extends this analysis to include offers made by producers for 2022 supply up to December 2021.

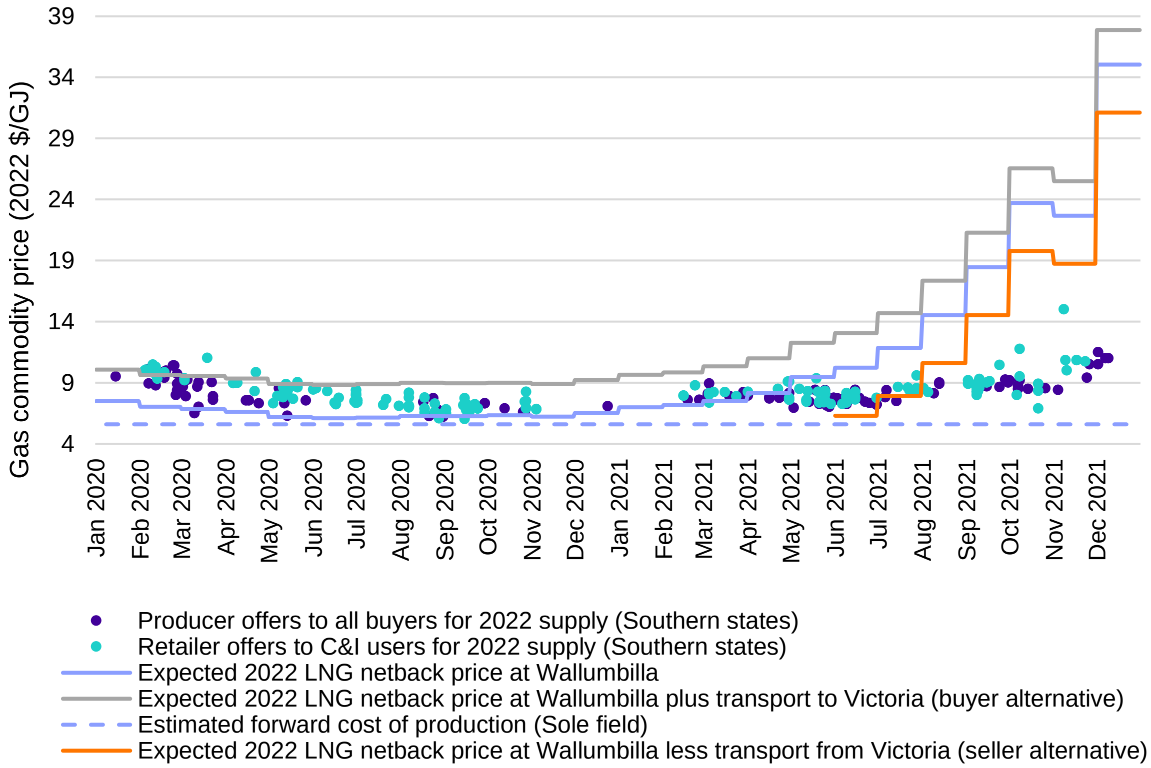
LNG netback price expectations increased further in the later part of 2021. While some prices offered remained significantly below netback, several offers from LNG exporters were priced in line with LNG netback.

A.2.3 Netback and domestic offers comparison (Southern states)

Chart A.4 compares offers by producers and retailers in the southern states for 2021 supply made between 1 January 2030 and 31 December 2021 with:

- expectations of 2022 LNG netback and the buyer alternative price as at the time the offer was made, and
- with the estimated forward costs of production for marginal gas production in the southern states.

Chart A.4: Gas commodity prices offered by producers to all buyers, and retailers to C&I users for 2022 supply in the southern states ($2022/GJ)



Source: ICE, Argus, ACCC analysis of other information provided by suppliers.

Note: The above chart only includes offers that relate to contracts with a term of 1–3 years. Offers that specify pricing mechanisms linked to oil prices have been excluded.

Our January 2022 report noted that in from June to August 2021 prices offered for supply to the southern states clustered around the seller alternative for the first time. From August to December 2021, prices offered increased, though remained below LNG netback and the seller alternative.

A.3 Prices payable for supply in 2022

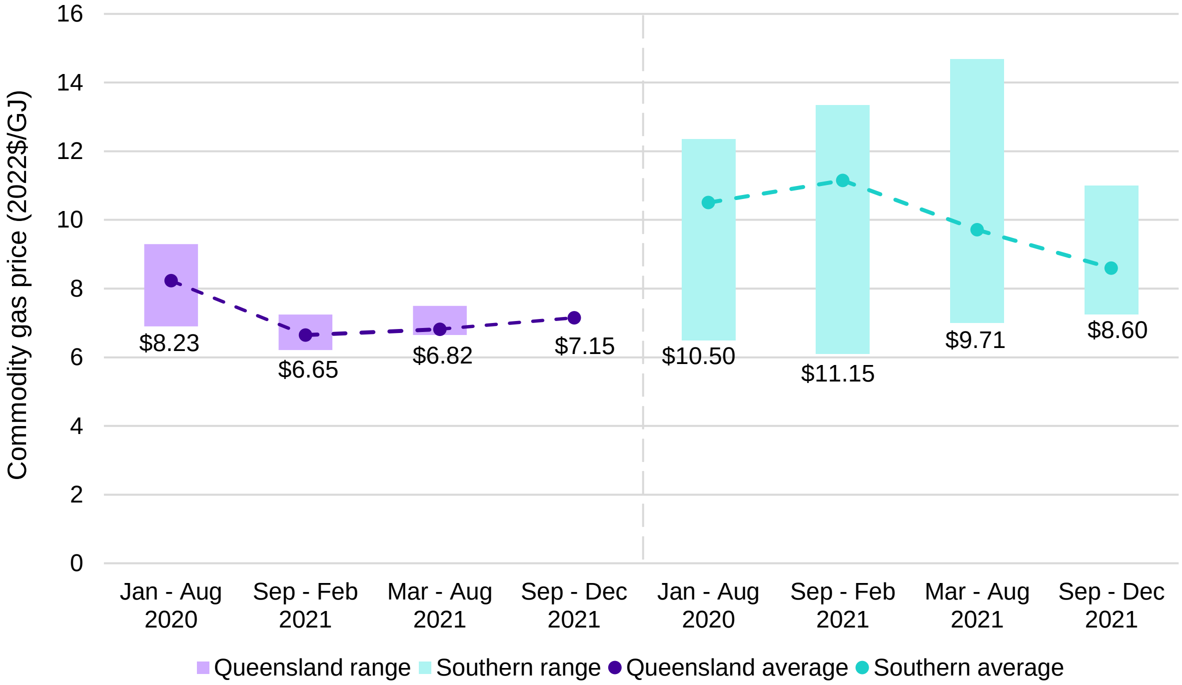
This section presents prices payable and volume flexibility agreed under GSAs for supply in 2022 that were entered into between 1 January 2020 and 31 December 2021.

Our approach to GSA analysis is described in appendix B.

A.3.1 Prices payable under GSAs for supply in 2022

Chart A.5 presents prices payable under producer GSAs for supply in 2022 which were executed between January 2020 and December 2021.

Chart A.5: Expected gas commodity prices (2022 $/GJ) payable under GSAs entered in the east coast gas market for 2022 supply (Producers)

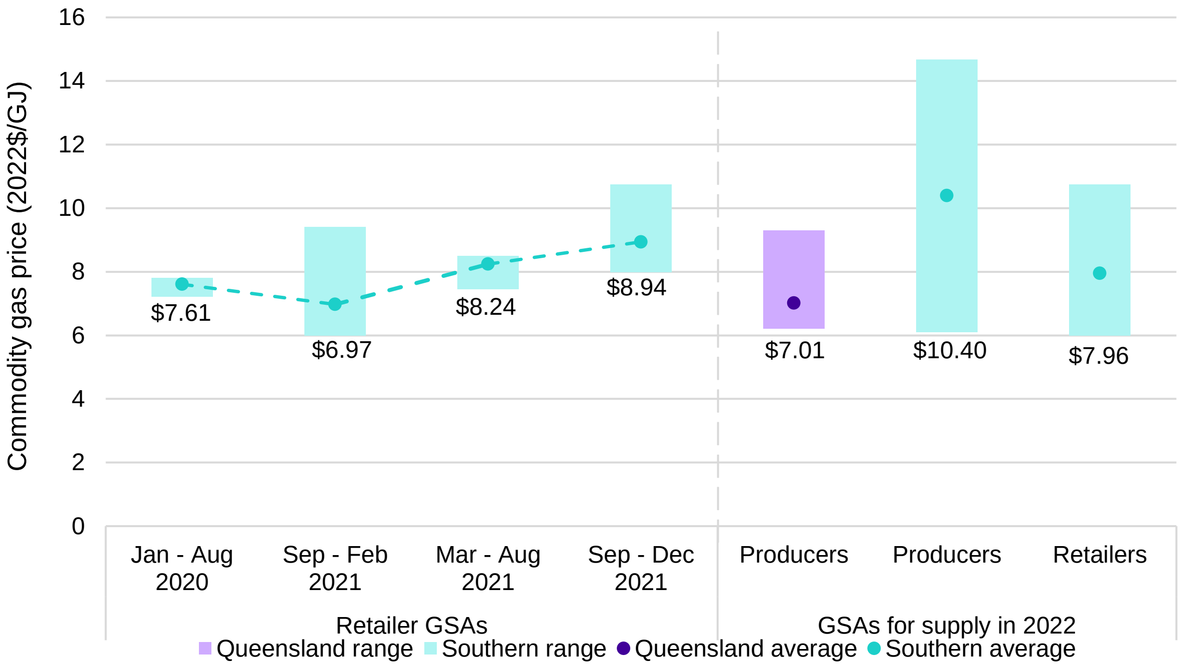


Source: ACCC analysis of information provided by suppliers.

Note: ACCC pricing model last updated on 14 June 2022.

Chart A.6 also presents prices payable for supply in 2021 under GSAs which were executed between January 2020 and December 2021.

Chart A.6: Expected gas commodity prices (2022 $/GJ) payable under GSAs entered in the east coast gas market for 2022 supply (Retailers)



Source: ACCC analysis of information provided by suppliers.

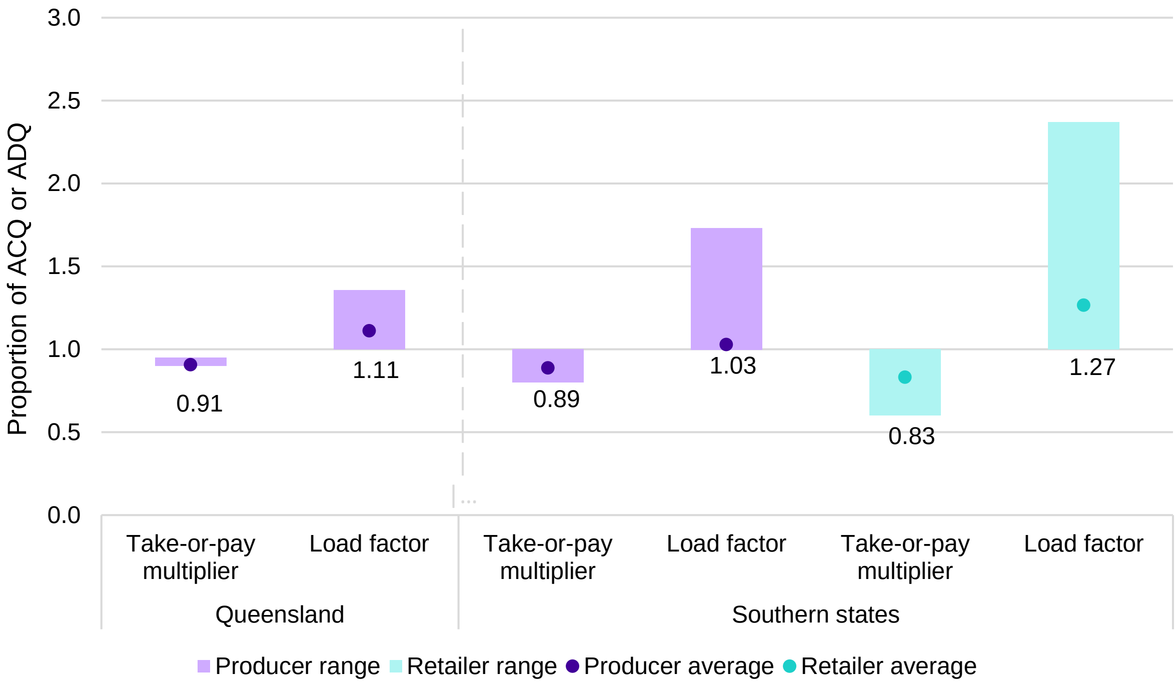
Note: Expected prices payable under GSAs executed by retailers in Queensland were excluded from this chart because an insufficient number of GSAs were executed between retailers and C&I users for supply in Queensland.

Pricing model last updated on 14 June 2022.

A.3.2 Flexibility under GSAs for supply in 2021

Chart A.7 presents quantity-weighted average take-or-pay multipliers and load factors under GSAs for supply in 2022 which were executed between January 2020 and December 2021.

Chart A.7: Average load factor and take-or-pay multiplier under GSAs entered in the east coast gas market for 2022 supply



Source: ACCC analysis of information provided by suppliers.

B. Approach to reporting on gas prices

This appendix sets out the ACCC's approach to reporting on prices offered, bid and agreed to under GSAs, as presented in chapter 2 and appendix A.

B.1 Parameters of reported prices

The following apply to our analysis of prices reported in chapter 2 and appendix A:

- Prices reported are GST exclusive
- Prices reported are wholesale gas commodity prices and do not include separate charges for transporting gas to the user's location or other ancillary charges (although delivery charges may, in some cases, be bundled with commodity gas prices). The prices charged for transportation have been excluded from our analysis to enable a more direct comparison between the prices paid by buyers in different locations and with differing transportation requirements.
- Only arm's length transactions are included. Related party transactions are excluded to ensure that the prices reported are reflective of market conditions.
- Only those transactions with a term of at least one year and an annual contract quantity of at least 0.5 PJ are included.
- Where average prices are reported, these are quantity-weighted average prices. Where average prices are reported for a region, these are based on the location at which the gas is to be delivered rather than the location at which the gas is produced.
- The following entities were classified as 'retailers': Origin Energy, AGL, EnergyAustralia, ENGIE, Alinta Energy, Shell Energy Australia, Macquarie Bank and Weston Energy.

We note that prices of individual transactions are not necessarily directly comparable due to differences in non-price aspects such as flexibility, quantity, contract term and delivery point. These non-price terms and the flexibility they can provide may be valued differently depending on the customer and may influence the gas prices that are ultimately agreed. The ACCC has not sought to adjust for these factors in the analysis presented in chapter 2 and appendix A.

B.2 Reporting on offers and bids

The information in this section describes our approach to reporting on offers and bids, as presented in section 2.3 and should be read in conjunction with information above in section B.1.

The following also applies to our analysis of offers and bids.

- The analysis only includes those offers and bids that contain clear indications of price, quantity, supply start and supply end dates.
- The commodity gas price for each offer and bid has been estimated using the pricing mechanisms specified in each offer or bid along with assumptions relating to key variables (for example, oil and LNG prices, foreign exchange rates and inflation) based on the expectations for those variables at the time of the offer or bid.[145]

[145] In all estimates of offer and bid prices in this report, the following assumptions were made, where relevant:

- The expected AUD/USD exchange rate is equal to the average rate prevailing during the month in which the offer or bid occurred (source: RBA)

- Some producer and retailer offers specify a pricing mechanism linked to Brent crude oil prices. We calculated an indicative price in such offers using the following approach:
  - For each day in the month in which an offer was made, we calculated the expected price of Brent crude oil for the year of supply (for example, 2022) by taking a simple average of Brent crude oil prices expected in each month of that year.
  - We then averaged these daily estimates to derive a monthly estimate for the year of supply.
  - We then applied this monthly estimate to the pricing mechanism specified in the offer to arrive at an indicative price.
- A similar approach is used to calculate an indicative price for offers and bids that specify a pricing mechanism linked to JKM (LNG) prices.

B.3. Comparing domestic price offers with expectations of future LNG netback prices

In sections 2.3.2 and 2.3.3 of this report, we compare prices offered (for those offers with fixed or JKM-linked pricing and a term of 1–3 years):

- for delivery in Queensland to expectations of LNG netback prices in Queensland and the estimated forward costs of production in Queensland in the month the offer or bid occurred
- for delivery in the southern states to the range of prices expected under a bargaining framework, outlined in previous ACCC reports, and the estimated forward costs of production in the southern states in the month the offer or bid occurred.

B.3.1 Approach to comparing offers in Queensland

We calculate LNG netback prices, based on Asian LNG spot prices, to compare against prices offered in Queensland (which is where the east coast gas market's LNG export facilities are located).

Asian LNG spot markets provide an alternative for LNG exporters to selling gas in the domestic market. As such, Asian LNG spot prices are likely to influence domestic gas prices under current market conditions. While LNG netback prices likely play an important role in the east coast gas market, they are not likely to be the sole factor influencing domestic prices.

The gas prices received by producers will also depend on the location of gas fields, the marginal cost of supply, the buyer's maximum willingness to pay and the demand-supply balance, the importance of which will differ over time.

To calculate an LNG netback price to compare against offers for future supply, we have:

- calculated a forward-looking LNG netback price as at the date of the offer – based on market expectations of future LNG spot prices during the period of supply – as this gives

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- The expected Brent Crude oil price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: Bloomberg).
- The expected Japan Korea Marker (JKM) LNG price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: ICE).
- The applicable CPI is based on actual CPI where available at the time the bid or offer occurred (up to the most recent available quarter, source: ABS), and 2.5% thereafter.

the best indication of the likely opportunity cost of supplying gas to the domestic market[146]

- used short-run incremental costs of LNG production and transport, since LNG exporters are making decisions about the sale of excess gas over the short-run.

We have calculated LNG netback prices using the method and assumptions used for the LNG netback price series, which is regularly published on the ACCC's website, and which is described in detail in the ACCC's Guide to the LNG netback price series.[147]

The domestic offers analysed in sections 2.3.2 and 2.3.3 are all for gas supply over the entire calendar year. Therefore, for the purpose of comparison for offers in a given year, 2021 as an example, we calculated an average 2021 LNG netback price that an LNG exporter would expect to receive to be indifferent between selling the gas to the domestic buyer over the entirety of 2021, and selling cargoes on the Asian LNG spot market in 2021.

For example, we calculated the average of LNG netback prices for 2021 that an LNG exporter would have expected in July 2020 as follows:

- We obtained JKM futures prices for each month of 2021 that were quoted by ICE on each day during July 2020.
- We converted the monthly 2021 JKM futures prices into LNG netback prices at Wallumbilla by:
  - converting the prices from USD$/MMBtu into AUD$/GJ using contemporaneous exchange rates and a conversion factor between MMBtu and GJ
  - subtracting the short-run marginal costs of shipping, liquefaction[148] and transportation.[149]
- We averaged these monthly LNG netback prices to arrive at an average of LNG netback prices for 2021 expected on each day during July 2020.
- We then averaged these 2021 expectations for each day of July 2020 to arrive at an average of LNG netback prices for 2021 expected during the month of July 2020.

As has been noted before, our approach to calculating LNG netback prices does not involve deducting the capital costs of building the Queensland LNG export facilities. This is because these costs are sunk and do not influence the decisions of LNG exporters, at the margin, to supply excess gas to the domestic or export markets.

Moreover, LNG spot prices are determined by short-run LNG market dynamics, such as LNG supply into spot markets, the level of competition, as well as demand and the ability for buyers to switch to alternative fuel sources (such as coal). These short-run dynamics are influenced by short-run supply, which in turn is determined by short-run incremental costs for the marginal supplier of LNG to spot markets (which are not influenced by the capital costs of building LNG export facilities).

There may be times, however, where LNG spot prices would be sufficiently high to allow LNG exporters to recover apportioned capital costs (for their relevant LNG facility). There are also likely to be periods in which the opposite would be the case. Historically low spot prices

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146 For this, we have used JKM futures prices (source: ICE).

147 ACCC, Guide to the LNG netback price series, https://www.accc.gov.au/system/files/Guide to the LNG netback price series - October 2018_0.pdf

148 We estimated the incremental costs of liquefaction and fuel used in the operation of the LNG trains based on data obtained from LNG exporters in Queensland.

149 We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from LNG exporters.

in early 2020, which have been well below prices payable for LNG under long-term contracts, may not allow for recovery of capital costs. By some estimates, the long-run costs of the Queensland LNG projects are above USD$10/MMBtu; well above current LNG spot prices.[150]

B.3.2 Approach to comparing offers in the southern states

Due to the cost of transportation between the southern states and Queensland, there is a range of possible pricing outcomes in gas supply negotiations in the southern states, which would usually be expected to fall between:

- the buyer alternative (representing a ceiling in negotiations) – the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location
- the seller alternative (representing a floor in negotiations) – the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the forward cost of production (whichever is higher).

Where a price actually achieved in a negotiation will fall within this range is likely to depend on a number of factors, including the location of the buyer, the expectations of the parties about supply and demand dynamics in the southern states, the relative bargaining strength of the parties and the non-price terms and conditions agreed by the parties.

The supply-demand outlook in the southern states is particularly important to the outcome. If there are limited supply options for gas users in the southern states, such as in the case of an expected gas supply shortfall, users that are unable to reach an agreement for gas supply with a southern supplier will need to transport gas from Queensland. In this scenario, gas suppliers in the southern states would be expected to offer a buyer alternative price in every region in the southern states.

Further, a southern supplier would be expected to seek a higher price the further away a gas user is from Queensland. Since gas users in Victoria are located further away from Queensland than users in NSW and South Australia, they will likely be offered higher prices than users in those other states, all other things equal. If, in a well-functioning market, a southern supplier were to make an offer above this, then regardless of the location of the buyer it would likely be more economic for the buyer to purchase gas from Queensland and transport it to its location. Therefore, the buyer's alternative price in Victoria is indicative of the maximum price that would be likely to prevail in a well-functioning market.

Conversely, if there were sufficient supply and diversity of suppliers in the southern states, this would be likely to alter the relative bargaining positions of gas suppliers and gas buyers. Gas buyers would be able to source gas from another supplier in the southern states rather than having to transport it from Queensland, and increased competition would be likely to lead suppliers to offer prices closer to the 'seller alternative' price. In this scenario, the prices offered by suppliers in the southern states would be lower the further away the source of supply is from Queensland, but not below the forward cost of production. The forward cost of production therefore sets the floor price in any gas supply negotiation.

To meaningfully analyse the level of prices offered in a particular location in the southern states using this bargaining framework, it is necessary to compare those prices to the buyer/seller alternative range in that specific location. In the analysis in chapter 2 and appendix A we present a buyer and seller alternative for Victoria.

We note that the LNG netback price and buyer and seller alternative price do not account for other factors that may influence the prices offered to gas buyers, such as flexible non-price

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150 Ferrier Hodgson, National Resources Insights, 2017

terms and conditions in GSAs, the contract length and, in the case of retailer offers, retailer costs and margins.

B.3.3 Forward costs of production

In 2018, we engaged Core Energy (Core) to develop detailed estimates of the gas production costs facing producers in the east coast gas market. For individual supply regions across the east coast, Core estimated both full lifecycle costs of production and forward costs of production for 2P reserves as at 31 December 2017.[151]

The analysis in sections 2.3.2 and 2.3.3 compares price offers for 2022 and 2021 supply with estimates of forward production costs, since over the short-term producers are likely to continue producing gas as long as they expect to recover their operating costs.

Core Energy's report on gas production costs estimated the costs of production for a range of areas. We have chosen to use the estimated forward costs for the marginal source of supply in Queensland and Victoria, as this would likely set the price floor in negotiations between gas suppliers and buyers in those states.

For Queensland, we chose the Middle Surat and Roma Shelf supply region as it has material uncontracted 2P reserves (9,260 PJ) that Core expected to commence production by 2020 and that Core estimated to have the highest forward cost ($5.55/GJ).

The choice of the marginal supplier in Victoria is more complicated. Based on the bargaining framework set out above, the marginal supplier in Victoria comes into the analysis in the circumstance where substantially more gas is produced in the southern states than there is demand in the southern states (such that the prices start to trend towards the seller alternative). In those circumstances, the production costs of the marginal supplier in the southern states would set the floor in pricing negotiations. It is likely that additional production from new sources would be required for the southern states to reach such a state. In those circumstances, the new source of supply would likely be the marginal supplier.

It is difficult to predict what the new source of supply would be or what the forward production cost of the marginal supplier is likely to be. For the purpose of the analysis in chapter 2 and appendix A, we have chosen the Sole gas field as a proxy for the costs of a new marginal supplier. The Sole field is a new source of production in the south and its costs are therefore indicative of the likely costs of a new supplier. According to Core's estimates, Sole had 249 PJ of 2P reserves with an estimated forward production cost of $5.60/GJ as at 31 December 2017.[152]

B.4 Reporting on GSA pricing and flexibility

The information in this section describes our approach to reporting on GSAs, as presented in section 2.4.1 should be read in conjunction with information above in section B.1

The following also applies to our analysis of GSAs:

- For the purpose of the analysis of producer prices, we have included GSAs executed at arm's length by producers with all counterparties. For the purpose of the analysis of retailer prices, we have only included GSAs between retailers and C&I users. Analysis may also include price amendments.

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[151] Core Energy, Gas Production Cost Estimates: Eastern Australia, 2018, https://www.accc.gov.au/system/files/Core Energy report for ACCC - November 2018.pdf

[152] We intend to update the assumptions and costs estimates for future reports using data published by AEMO on production costs in the east coast gas market.

- We estimated prices payable using recent expectations of key variables, including, where relevant, the AUD/USD foreign exchange rate, inflation, Brent Crude oil and JKM.[153] To estimate the price payable in a given supply year, we have taken the simple average of expected prices in each supply month in that year.

We also report on the average load factor and take or pay multiplier in section 2.4.2. Both the load factor and the take-or-pay multiplier are measures of the level of flexibility allowed under the contract. Specifically:

- The load factor is calculated as the ratio of the annual aggregate of the maximum daily quantities allowed under the GSA and the annual contract quantity. The higher the load factor, the more gas a gas user can take on a given day above their average daily allowance.
- The take-or-pay multiplier is the percentage of the contracted gas that must be paid for by the buyer whether or not the buyer actually takes delivery of the gas. A GSA with a take-or-pay multiplier of 100% implies that the buyer has to pay for all of the gas it has contracted to take, irrespective of whether it uses the gas in the year. A GSA with a take or pay multiplier of 0% is considered an option contract as the buyer does not have any obligation to purchase gas under the contract.

[153] This differs to our approach to reporting on prices offered and bid, in which we estimate prices based on expectations in the month the offer or bid occurred.

Glossary

ACCC's 2015 inquiry: The ACCC's inquiry into the East Coast Gas Market in 2015, as reported on in April 2016.

Annual contract quantity: The quantity of gas specified in the transportation contract between the buyer and the seller, based on the buyer's maximum historical 12-month usage.

Buyer alternative: the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location. It represents a price ceiling in negotiations.

Capacity trading platform: An online platform that shippers can use to trade secondary capacity ahead of the nomination cut-off time. It provides for exchange-based trading of commonly traded products and a listing service for more-bespoke products. The CTP forms part of the Gas Supply Hub exchange.

Congestion: A pipeline is congested when there is insufficient spare capacity to transport the volume of gas to fulfil demand. Physical congestion refers to where demand for actual deliveries exceeds the technical capacity of the pipeline at some point in time, whereas a pipeline is contractually congested when the demand for firm capacity exceeds the technical capacity of the pipeline.

Contracted but un-nominated capacity: A quantity of contracted pipeline capacity that is not nominated to be used by a shipper on a gas day.

Conventional/unconventional gas: Conventional gas is contained in sedimentary rocks such as sandstone and limestone (referred to as reservoir rock). The gas is trapped by an impermeable cap rock and may be associated with liquid hydrocarbons. The reservoir rock has a relatively high porosity (percentage of space between rock grains) and permeability (the rock's pores are well connected and the gas may be able to flow to the gas well without additional interventions). Gas is extracted by drilling a well through the cap rock allowing gas to flow to the surface. Depending on the structure of the rock containing the gas (amount of faulting or compartmentalisation), only a few wells may be required to produce gas over the life of the gas field.

Unconventional gas is a broad term that covers gas found in a range of sedimentary rocks which typically have low permeability and porosity. The International Energy Agency categorises the three major types of unconventional gas as:

- **shale gas:** natural gas contained within shale rock
- **coal seam gas (CSG):** natural gas contained in coalbeds
- **tight gas:** natural gas found in low permeability rock formations.

A range of techniques may be required to promote gas flow including pumping water from the rock to reduce pressure holding the gas in place (in the case of CSG) or hydraulic fracture stimulation (fracking) to open pathways for the gas to enter the well (in the case of shale gas, tight gas and some CSG). An unconventional gas field may require a large number of wells to be drilled (in the thousands for the large CSG liquefied natural gas (LNG) projects in Queensland) over its life to ensure consistent production.

Day-ahead auction: An auction of contracted but un-nominated capacity. It is conducted after nomination cut-off and is subject to a reserve price of zero. Compressor fuel is provided in-kind by shippers.

Domestic demand: The quantity of gas demanded by users located in Australia.

Downward quantity tolerance: The amount a buyer may fall short of its full Annual Contract Quantity in a Take or Pay gas sales contract without incurring penalties.

East coast gas market: The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Export demand: The quantity of Australian gas demanded by overseas buyers.

Gas storage service: A service that allows users to store gas in a facility (either underground depleted gas fields or domestic LNG storage).

Gas supply agreement: A contract between the buyer and seller for the supply of gas

Gas transportation agreement: A contract between the shipper and the pipeline operator for the transport of gas on that pipeline

Heads of Agreement: In the context of this report, this refers to an agreement between LNG exporters and the Australian Government to offer uncontracted gas first to the domestic market on 'competitive market terms' before it is offered to the international market.

Henry Hub: Is the major gas hub for spot and futures trading in the United States and acts as the notional point of delivery for gas futures contracts. Henry Hub is based on the physical interconnection of nine interstate and four intrastate pipelines in Louisiana.

Japan Korea Marker: Is an international benchmark price for LNG spot cargos. It reflects the spot market value of cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan.

Japan Customs Cleared: Represents the average price of crude oil imported to Japan and reported by the Japanese Custom. It is commonly used as an index by LNG traders.

Liquefaction: The process of liquefying natural gas.

Liquefied natural gas (LNG): Natural gas that has been converted to liquid form for ease of storage or transport.

LNG exporter: LNG exporters process and prepare natural gas, using liquefaction, into LNG for transmission and sale to overseas markets. In this report, the term is usually used in reference to one or more of the three LNG exporters in Queensland, being Australia Pacific LNG (APLNG), QGC, and Gladstone LNG (GLNG). There are also LNG exporters in the Northern Territory and in Western Australia.

LNG netback price: A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or 'netting back' costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port.

LNG train: A liquefied natural gas plant's liquefaction and purification facility.

Load factor: measures the extent to which a buyer can take more than the average daily contract quantity throughout the year, subject to the cap imposed by the annual contract quantity.

Looping: Increasing the capacity of a pipeline system, by adding parallel piping along parts or the whole of the route. This does not include adding compression facilities.

Pipeline transportation services

As available transportation service: A service that allows the transportation of gas on an ‘as available’ basis, subject to the availability of capacity. This service has a lower priority than a firm transportation service.

Compression service: A service that increases the pressure of gas to improve the efficiency of transportation. Compression services are provided by compression service facilities.

Firm transportation service: A service that allows the transportation of gas on a ‘firm’ basis up to a maximum daily quantity and maximum hourly quantity. It has the highest priority of any transportation service.

Interruptible transportation service: A service that allows the transportation of gas on an ‘interruptible’ basis. The pipeline operator does not have an obligation to guarantee capacity and has the right to curtail the service if the pipeline becomes capacity constrained or higher priority services are required. This service has a lower priority than firm and as available transportation services.

Loan service: A service that allows users to “borrow” gas from a pipeline, which in practice involves withdrawing more gas from a pipeline than what is injected on a particular day.

Park service: A service that allows users to store gas in a pipeline, which in practice involves injecting more gas into a pipeline than what is taken out on a particular day.

Producer: Gas producers extract gas and process it for transmission and sale.

Reserves and resources

Reserves: Quantities of gas expected to be commercially recoverable from a given date under defined conditions.

Developed reserves: Gas expected to be recovered from existing wells and facilities

Undeveloped reserves: Gas that requires further investments to bring online.

1P (proved) reserves: Commercially recoverable reserves with at least a 90 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

2P (proved and probable) reserves: Commercially recoverable reserves with at least a 50 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

3P (proved and probable and possible) reserves: Commercially recoverable reserves with at least a 10 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

Contingent resources: quantities of gas estimated to be potentially recoverable from known accumulations but are not yet considered able to be developed commercially due to one or more contingencies. Contingent resources may include gas accumulations for which there are currently no viable markets, where commercial recovery is dependent on technology under development or where evaluation of the accumulation is insufficient to assess if it can be produced commercially. 2C resources are classified as a best estimate of the resource (1C is the low estimate and 3C is the high estimate).

Prospective resources: Estimated quantities associated with undiscovered gas. These represent quantities of gas which are estimated, as of a given date, to be potentially recoverable from gas deposits identified on the basis of indirect evidence but which have not yet been drilled. Prospective resources represent a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the gas accumulation must be further evaluated and an estimate made of quantities that would be recoverable under appropriate development projects.

Retailer: For the purpose of this report, this term captures both entities that purchase natural gas in wholesale markets to sell to retail customers and entities that purchase natural gas in wholesale markets to resell to other buyers in those markets. This includes AGL, Alinta Energy, EnergyAustralia, Macquarie Bank, Power and Water Corporation, Origin Energy and Shell Energy Australia.

Sale and purchase agreement: An agreement between the buyer and seller for LNG. In this report

Secondary capacity: Capacity that is on-sold by primary capacity holders on a pipeline.

Seller alternative: the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the forward cost of production (whichever is higher). It represents a price floor in negotiations

Shipper: A user or prospective user of pipeline services.

Southern states: South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Spot market transaction: The sale or purchase of gas using a spot market. In Australia's facilitated markets, these are typically for delivery on a single gas day shortly after the transaction has been finalised. Australia's Gas Supply Hub allows for the trade of gas over longer time frames (i.e. more than one day). Spot market transactions are distinct from transactions under gas supply contracts.

Standing prices: prices or reference tariffs that pipelines subject to Part 23 of the National Gas Rules, light regulation or full regulation are required to publish.

Swap arrangement: An arrangement between two or more gas market participants to swap rights or obligations. For example, two gas producers in different locations may swap gas delivery obligations to minimise transportation.

Take or pay: A contract term specifying the minimum proportion of ACQ the buyer must pay for in each year. Take-or-pay multipliers are expressed as a percentage in GSAs, and provide users with flexibility in how they manage their gas usage.

Tenement: A claim, lease or licence for the purpose of prospecting or mining gas.

Units of Energy

Joule—a unit of energy in the International System of Units

Gigajoule (GJ)—a billion joules

Terajoule (TJ)—a trillion joules

Petajoule (PJ)—a quadrillion joules

Million British Thermal Units (MMBtu)—a unit of heat; 1 MMBtu = approximately 1.055 GJ